# BEFORE THE
# PENNSYLVANIA PUBLIC UTILITY COMMISSION

# PENNSYLVANIA PUBLIC UTILITY COMMISSION
**v.**
# PECO ENERGY COMPANY - ELECTRIC DIVISION

## DOCKET NO. R-2015-2468981

## VOLUME VIII

**Defined Filing Requirements**
**Section 53.53**
**Rate of Return**
**Rate Structure and Cost Allocation /**
**Plant and Depreciation Supporting Data,**
**Including Related Depreciation Study Report /**
**Unadjusted Comparative Balance Sheets**
**and Operating Income Statements**

Q. III-A-1 Provide a schedule showing the major components of claimed capitalization, and the derivation of the weighted costs of capital for the rate case claim. This schedule shall include a descriptive statement concerning the major elements of changes in claimed capitalization, cost rates and overall return from comparable historical data.

A. III-A-1 The components of the Company's proposed weighted average cost of capital can be found in Schedules 1, 5, and 6 of PECO Exhibit PRM-1. The major changes in the Company's capitalization relate to the issuance of new debt and build-up of retained earnings in the future and fully projected future test years. The components in this regard are shown in the footnotes to Schedule 5 of PECO Exhibit PRM-1.

Q. III-A-2 Provide a schedule in the same format as Schedule 1, except for the omission of the descriptive statement, for the most immediate comparable annual historical period prior to the test year and the two calendar years most immediately preceding the rate of return claim period. Irrespective of whether the capitalization claimed on Schedule 1 includes short-term debt, Schedule 2 should reflect capital ratios with and without short-term debt.

A. III-A-2 Refer to the response to III-A-1.

Q. III-B-1 Provide a schedule showing the calculation of embedded cost of long-term debt by issue, supporting the related rate case claim. The schedule shall contain the following information:

a. Date of issue
b. Date of maturity
c. Amount issued
d. Amount outstanding
e. Amount retired
f. Amount reacquired
g. Gain or loss on reacquisition
h. Coupon rate
i. Discount or premium at issuance
j. Issuance expense
k. Net proceeds
l. Sinking fund requirements
m. Effective cost rate
n. Total average weighted effective cost rate

A. III-B-1 Refer to Exhibit PRM-1, Schedule 6.

Q. III-B-2 In the event that a claim made for a true or economic cost of debt exceeds that shown in the preceding nominal cost schedule because of convertible features, sale with warrants or for any other reason, a full statement of the basis for such a claim should be provided.

A. III-B-2 The Company is not making such a claim in this proceeding.

Q. III-B-3

Provide the following information concerning bank notes payable for actual test year:

a. Line of Credit at each bank.
b. Average daily balances of notes payable to each bank, by name of bank.
c. Interest rate charged on each bank note (Prime rate, formula rate or other).
d. Purpose of each bank note (e.g., construction, fuel storage, working capital, debt retirement).
e. Prospective future need for this type of financing

A. III-B-3

a.-e. PECO Energy Company (PECO) has access to unsecured credit facilities with aggregate bank commitments of $600 million and $34 million which terminate in May 2019 and October 2015, respectively.

As of September 30, 2014, PECO had no outstanding borrowings under the $600 million credit facility, which can be used for general corporate purposes, including meeting short-term funding requirements and the issuance of letters of credit. The $600 million credit facility was used primarily to provide back-up credit support for PECO's commercial paper program and to issue letters of credit. PECO had $1M in outstanding letters of credit under this facility at September 30, 2014. If PECO were to draw on this unsecured facility with the aggregate bank commitments of $600M, the interest rate would be LIBOR plus 90 basis points, based on PECO's current credit rating.

The $34 million credit facility with Community and Minority Banks is used primarily to issue letters of credit to provide support for PECO's workmen's compensation and certain benefit claim obligations. PECO had $20.6 million of outstanding letters of credit as of September 30, 2014. If PECO where to draw on the facility, the interest rate would be LIBOR plus 90 basis points based on PECO's current credit rating.

PECO is expected to continue to meet its short-term liquidity requirements through the issuance of commercial paper. PECO may also use its credit facilities for general corporate purposes, including the funding of short-term liquidity requirements and the issuance of letters of credit.

Q. III-B-4 Provide detailed information concerning all other short-term debt outstanding.

A. III-B-4 For the most recent 24 months (FY13 and FY14), PECO did not have a short-term debt balance outstanding at the end of any month.

Q. III-B-5

Describe long-term debt reacquisition by issue by Company and Parent as follows:

a. Reacquisition by issue by year.
b. Total gain or loss on reacquisitions by issue by year.
c. Accounting for gain or loss for income tax and book purposes.
d. Proposed treatment of gain or loss on such reacquisition for ratemaking purposes

A. III-B-5

There have been no debt reacquisitions for PECO Energy Company from 2010-2014. Exelon Corporation debt reacquisitions are not applicable.

Q. III-C-1 Provide a schedule showing the calculation of the embedded cost of preferred stock equity by issue, supporting the related rate case claim. The schedule shall contain the following information:

a. Date of issue
b. Date of maturity
c. Amount issued
d. Amount outstanding
e. Amount retired
f. Amount reacquired
g. Gain or loss on reacquisition
h. Dividend rate
i. Discount or premium at issuance
j. Issuance expenses
k. Net proceeds
l. Sinking fund requirements
m. Effective cost rate
n. Total average weighted effective cost rate

Projected new issues, retirement and other major changes from the comparable historical data should be clearly noted.

A. III-C-1 Currently, PECO has no preferred stock outstanding, and does not project issuing preferred stock.

On May 1, 2013 PECO Energy Company redeemed the various series of preferred stock shown below, which constituted all of PECO's outstanding preferred stock:

- $3.80 Preferred Stock = 300,000 shares @ $106.00 = $31,800,000.00 (Principal = $30,000,000.00)
- $4.30 Preferred Stock = 150,000 shares @ $102.00 = $15,300,000.00 (Principal = $15,000,000.00)
- $4.40 Preferred Stock = 274,720 shares @ $112.50 = $30,906,000.00 (Principal = $27,472,000.00)
- $4.68 Preferred Stock = 150,000 shares @ $104.00 = $15,600,000.00 (Principal = $15,000,000.00)

PECO paid $93,606,000 to redeem preferred stock with a total principal amount outstanding of $87,472,000.

See **Attachments III-C-1(a-f)** for supporting details.

WELLS FARGO

April 30, 2013

Brian Collins
Exelon Corporation
10 S. Dearborn St.
Chicago, IL 60680

Dear Mr. Collins:

This letter is to confirm the funds required for the redemption of PECO Energy Company preferred stock as follows:

$3.80 Preferred Stock = 300,000 shares @ $106.00 = $31,800,000.00
$4.30 Preferred Stock = 150,000 shares @ $102.00 = $15,300,000.00
$4.40 Preferred Stock = 274,720 shares @ $112.50 = $30,906,000.00
$4.68 Preferred Stock = 150,000 shares @ $104.00 = $15,600,000.00

Total Funds required = $93,606,000.00

Please arrange to wire the funds on Wednesday, May 1, 2013, for receipt no later than 10:00 a.m. Central Time using the wire instructions below.

**Wells Fargo Bank, N.A.**
**420 Montgomery Street**
**San Francisco, CA 94104**

**ABA # 121000248**
**Account # 1067899**
**Account Name: Stock Transfer Wire Clearing Account**
**For Further Credit to: PECO Energy (Attn Donna Boehm)**

Feel free to contact me if you need additional information.

Kind Regards,

Becky Paulson

Becky Paulson
Vice President/Relationship Manager
Wells Fargo Shareowner Services
1110 Centre Pointe Curve, Suite 101
Mendota Heights, MN 55120

GRAB

## PREFERRED SECURITY DISPLAY Page 1/ 2

PECO ENERGY (EXC ) $ 3.8000 Series A [EXCH]

| CUMULATIVE | IDENTIFIERS |
|---|---|
| Name PECO ENERGY CO | EXCH SYM PE A |
| Industry Utilities | ISIN US6933042060 |
| Market of Issue Public | CUSIP 693304206 |
| **SECURITY INFORMATION** | **RATINGS** |
| Country US Currency USD | Moody's Baa2 |
| New/Old/Partial N | S&P BB+ |
| Calc Typ( 56)FIXED TYPE PRFD | Fitch BBB |
| Workout PERPETUAL Series A | Composite BBB- |
| PERP/CALL 4/10/13@ 106.00 | **ISSUE SIZE** |
| Div $3.8 Fixed | Amt Issued/Outstanding |
| QUARTLY 30/360 | 300,000.00 SHR/ |
| Announcement Dt 12/ 4/46 | 300,000.00 SHR |
| Ex-Div Date 12/27/12 | Min Piece/Increment |
| 1st Settle Date 12/10/46 | 100.00/ 100.00 |
| Div Pay Date 2/ 1/13 | Par Amount 100.00 |
| Iss Pr 104.1100 | **BOOK RUNNER/EXCHANGE** |
| | W.C. LANGLEY |
| NO PROSPECTUS DTC | NEW YORK |

1) Additional Sec Info
2) Call Schedule
3) Corporate Actions
4) Cds Spreads/RED Info
5) Ratings
6) Custom Notes
7) Identifiers
8) Sec. Specific News
9) Issuer Information
10) Pricing Sources
11) Pfd Dividend Hist.
12) Related Securities
13) Issuer Web Page

66) Send as Attachment

ALSO LISTED ON PHILADELPHIA EXCH. SER 2 PFD. O/S: AR 91

Australia 61 2 9777 8600 Brazil 5511 3048 4500 Europe 44 20 7330 7500 Germany 49 69 9204 1210 Hong Kong 852 2977 6000
Japan 81 3 3201 8900 Singapore 65 6212 1000 U.S. 1 212 318 2000 Copyright 2013 Bloomberg Finance L.P.
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## PREFERRED SECURITY DISPLAY Page 1/ 2

PECO ENERGY CO (EXC ) $ 4.3000 Series B [EXCH]

| CUMULATIVE | IDENTIFIERS | |
|---|---|---|
| Name PECO ENERGY CO | EXCH SYM PE B | 1) Additional Sec Info |
| Industry Utilities | ISIN US6933043050 | 2) Call Schedule |
| Market of Issue Public | CUSIP 693304305 | 3) Corporate Actions |
| **SECURITY INFORMATION** | **RATINGS** | 4) Cds Spreads/RED Info |
| Country US Currency USD | Moody's Baa2 | 5) Ratings |
| New/Old/Partial N | S&P BB+ | 6) Custom Notes |
| Calc Typ( 56)FIXED TYPE PRFD | Fitch BBB | 7) Identifiers |
| Workout PERPETUAL Series B | Composite BBB- | 8) Sec. Specific News |
| PERP/CALL 4/10/13@ 102.00 | **ISSUE SIZE** | 9) Issuer Information |
| Div $4.3 Fixed | Amt Issued/Outstanding | 10) Pricing Sources |
| QUARTLY 30/360 | 150,000.00 SHR/ | 11) Pfd Dividend Hist. |
| Announcement Dt 2/ 5/48 | 150,000.00 SHR | 12) Related Securities |
| Ex-Div Date 12/27/12 | Min Piece/Increment | 13) Issuer Web Page |
| 1st Settle Date 2/17/48 | 100.00/ 100.00 | |
| Div Pay Date 2/ 1/13 | Par Amount 100.00 | |
| Iss Pr 100.0000 | **BOOK RUNNER/EXCHANGE** | |
| | MORGAN STANLEY | |
| NO PROSPECTUS DTC | NEW YORK | 66) Send as Attachment |

ALSO LISTED ON PHILADELPHIA EXCH. SER 3 PFD. O/S: AR 91

Australia 61 2 9777 8600 Brazil 5511 3048 4500 Europe 44 20 7330 7500 Germany 49 69 9204 1210 Hong Kong 852 2977 6000
Japan 81 3 3201 8900 Singapore 65 6212 1000 U.S. 1 212 318 2000 Copyright 2013 Bloomberg Finance L.P.
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**PREFERRED SECURITY DISPLAY** Page 1/ 2

PECO ENERGY CO (EXC ) $ 4.4000 Series C [EXCH]

| CUMULATIVE | IDENTIFIERS | |
|---|---|---|
| Name PECO ENERGY CO | EXCH SYM PE C | 1) Additional Sec Info |
| Industry Utilities | ISIN US6933044041 | 2) Call Schedule |
| Market of Issue Public | CUSIP 693304404 | 3) Corporate Actions |
| **SECURITY INFORMATION** | **RATINGS** | 4) Cds Spreads/RED Info |
| Country US Currency USD | Moody's Baa2 | 5) Ratings |
| New/Old/Partial N | S&P BB+ | 6) Custom Notes |
| Calc Typ( 56)FIXED TYPE PRFD | Fitch BBB | 7) Identifiers |
| Workout PERPETUAL Series C | Composite BBB- | 8) Sec. Specific News |
| PERP/CALL 4/ 8/13@ 112.50 | **ISSUE SIZE** | 9) Issuer Information |
| Div $4.4 Fixed | Amt Issued/Outstanding | 10) Pricing Sources |
| QUARTLY 30/360 | 274,720.00 SHR/ | 11) Pfd Dividend Hist. |
| Announcement Dt | 274,720.00 SHR | 12) Related Securities |
| Ex-Div Date 12/27/12 | Min Piece/Increment | 13) Issuer Web Page |
| 1st Settle Date | 100.00/ 100.00 | |
| Div Pay Date 2/ 1/13 | Par Amount 100.00 | |
| Iss Pr | **BOOK RUNNER/EXCHANGE** | |
| NO PROSPECTUS DTC | NEW YORK | 66) Send as Attachment |

ALSO LISTED ON PHILADELPHIA EXCH. 0/S: AR 91

Australia 61 2 9777 8600 Brazil 5511 3048 4500 Europe 44 20 7330 7500 Germany 49 69 9204 1210 Hong Kong 852 2977 6000
Japan 81 3 3201 8900 Singapore 65 6212 1000 U.S. 1 212 318 2000 Copyright 2013 Bloomberg Finance L.P.
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# PREFERRED SECURITY DISPLAY Page 1/ 2

PECO ENERGY CO (EXC ) $ 4.6800 Series D [EXCH]

| CUMULATIVE | IDENTIFIERS | |
|---|---|---|
| Name PECO ENERGY CO | EXCH SYM PE D | 1) Additional Sec Info |
| Industry Utilities | ISIN US6933045030 | 2) Call Schedule |
| Market of Issue Public | CUSIP 693304503 | 3) Corporate Actions |
| **SECURITY INFORMATION** | **RATINGS** | 4) Cds Spreads/RED Info |
| Country US Currency USD | Moody's Baa2 | 5) Ratings |
| New/Old/Partial N | S&P BB+ | 6) Custom Notes |
| Calc Typ( 56)FIXED TYPE PRFD | Fitch BBB | 7) Identifiers |
| Workout PERPETUAL Series D | Composite BBB- | 8) Sec. Specific News |
| PERP/CALL 4/10/13@ 104.00 | **ISSUE SIZE** | 9) Issuer Information |
| Div $4.68 Fixed | Amt Issued/Outstanding | 10) Pricing Sources |
| QUARTLY 30/360 | 150,000.00 SHR/ | 11) Pfd Dividend Hist. |
| Announcement Dt 5/ 1/53 | 150,000.00 SHR | 12) Related Securities |
| Ex-Div Date 12/27/12 | Min Piece/Increment | 13) Issuer Web Page |
| 1st Settle Date 5/ 1/53 | 100.00/ 100.00 | |
| Div Pay Date 2/ 1/13 | Par Amount 100.00 | |
| Iss Pr 101.7500 | **BOOK RUNNER/EXCHANGE** | |
| | W.C. LANGLEY | |
| NO PROSPECTUS DTC | NEW YORK | 66) Send as Attachment |

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Australia 61 2 9777 8600 Brazil 5511 3048 4500 Europe 44 20 7330 7500 Germany 49 69 9204 1210 Hong Kong 852 2977 6000
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# Wallstreet Suite - Cash Record Details

WALLSTREET SYSTEMS

**Payment Factory** **Banking** **Reporting** **Admin**

Cash Monitor | Release Payments | Cash Reconciliation | Cash Transaction Report

## Cash Record Details

**Principal Cash Record Information**

| | | | |
|---|---|---|---|
| **Customer Ref. ID** | 2890092 | **Transaction Date** | 30/Apr/13 |
| **Transaction Amount** | -93,606,000.00 USD | **Value Date** | 01/May/13 |
| **Comments** | | **Cash Record Status** | Released |
| **Entity** | PECO | **Counterparty** | STOCK TRANSFER WIRE CLEARING ACCOUN |
| **Bank** | BOFA USNY | **Bank** | |

**Related Cash Records**

| Cust. Ref. ID | Entity | P/R | Counterparty | Amount/Currency | Cash Record Status |
|---|---|---|---|---|---|
| 2890092 | PECO | P | STOCK TRANSFER WIRE CLEARING ACCOUN | -93,606,000.00 USD | Released |

**Selected Cash Record Detailed Information**

| | | | |
|---|---|---|---|
| **Customer Ref. ID** | 2890092 | **Transaction Date** | 30/Apr/13 |
| **Transaction Amount** | -93,606,000.00 | **Value Date** | 01/May/13 |
| **Transaction Currency** | USD | | |
| **Amount in Bank Acct Currency** | | **Bank Acct Currency** | USD |
| **Foreign Exchange Rate** | | **Bank Txn Load ID** | |
| **Comments** | | **Cash Record Status** | Released |
| **Entity** | PECO | **Counterparty** | STOCK TRANSFER WIRE CLEARING ACCOUN |
| **Bank** | BOFA USNY | **Bank** | |
| **Bank Account** | $PECO Energy Distribution/5800392150 | **Bank Account** | /1067899 |
| **Cash Flow Type** | COMMP | **Cheque Number** | |
| **Txn Classification** | Third Party,Payment | **Cash Flow Source** | Commercial |
| **Actual or Forecast** | Actual | **Import Batch ID** | None |
| **Payment Method** | WTA | **Release Batch ID** | 111185 |
| **Priority Status** | Non-urgent | **Cash Record ID** | 2890092 |
| **Counterparty Message** | FFC PECO ENERGY ATTN DONNA BOEHM | **Bank Reference Num** | |
| **Bank Instructions** | | **Group ID** | 2890092 |
| **Bank Message Status** | | | |

**Display Additional Information**

**Reconciliation** ☐ **Contact & Banking** ☐ **Additional Attributes** ☐ **Regulatory** ☐ **Remittance** ☐ **Auditing** ☐ **Accounting** ☐

Display Information

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Q. III-D-1 Provide complete support for claimed common equity rate of return.

A. III-D-1 Refer to PECO Statement No. 5, the direct testimony of Paul R. Moul.

Q. III-D-2 Provide a summary statement of all stock dividends, splits or par value changes during the two (2) calendar year periods preceding the rate case filing.

A. III-D-2 The requested information is provided below for PECO Energy Company and its parent, Exelon Corporation for calendar years 2013 and 2014.

**2014**

| | Common Stock Dividends Declared ($ millions) | Preferred Stock Dividends Declared ($ millions) | Stock Splits | Par Value Changes |
|---|---|---|---|---|
| **Exelon Corporation** | $1,071 | $13 | None | None |
| **PECO Energy Company** | $320 | None** | None | None |

**2013**

| | Common Stock Dividends Declared ($ millions) | Preferred Stock Dividends Declared ($ millions) | Stock Splits | Par Value Changes |
|---|---|---|---|---|
| **Exelon Corporation** | $1,254 | $14 | None | None |
| **PECO Energy Company** | $331 | $1 | None | None |

**On May 1, 2013, PECO redeemed all of its outstanding preferred securities; therefore no preferred stock dividends were declared or paid in 2014.

Q. III-D-3

Provide a schedule of all issuances of common stock, whether or not underwriters are used, for the most immediately available annual historical period and the 2 calendar years most immediate preceding the test year.

A. III-D-3

No common stock was issued by PECO during the referenced period.

Q. III-D-4 Submit details on the utility and parent company stock offerings – past 5 years to present – as follows:

a. Date of prospectus
b. Date of offering
c. Record date
d. Offering period – dates and numbers of days
e. Amount and number of shares offered
f. Offering ratio, if rights offering
g. Percent subscribed
h. Offering price
i. Gross proceeds per share
j. Expenses per share
k. Net proceeds per share (i. – j.)
l. Market price per share
   (1) At record date
   (2) At offering date
   (3) One month after close of offerings
m. Average market price during offering
   (1) Price per share
   (2) Rights per share – average value of rights
n. Latest reported earnings per share at time of offering
o. Latest reported dividends at time of offering

A. III-D-4 There have been no common stock offerings in the past 5 years for PECO Energy Company.

There has been one common stock issuance by PECO's parent, Exelon Corporation within the last five years. On June 11, 2014, Exelon issued common stock to finance a portion of its proposed acquisition of Pepco Holdings Inc. and for general corporate purposes. In connection with that common stock offering, Exelon entered into forward sale agreements with an affiliate of Barclays Capital Inc. and Goldman, Sachs & Co. (the "forward counterparties"). Under those agreements, Exelon agreed to issue and sell to the forward counterparties (subject to Exelon's right to a cash or net share settlement of the forward sale agreements) the same number of shares of Exelon's common stock sold by the forward counterparties (or their respective affiliates) in the underwritten public offering. Settlement of the forward sale agreements will occur on dates to be specified by Exelon , but must occur no later than October 29, 2015. Upon settlement of the forward sale agreements, Exelon will issue and deliver to the forward counter parties shares of its common stock in exchange for cash proceeds per share equal to the forward sale price.

Details are below:

**Date of prospectus:** May 23, 2014
**Date of offering:** June 11, 2014
**Record date:** n/a
**Offering period – dates and numbers of days:** June 11, 2014, one day
**Amount and number of shares offered:** 57.5 million shares (initially offered 50 million shares. Underwriters were granted a 30-day option to purchase an additional 7.5 million shares of Exelon Corp common stock upon the same terms).
**Offering ratio, if rights offering:** n/a
**Percent subscribed:** n/a
**Offering price:** Public offering price was $35.00. Forward sale price (public offering price, less underwriting discounts and commissions) was $33.95, subject to certain adjustments as provided in the forward sales agreement.
**Gross proceeds per share:** $35.00
**Expenses per share:** $1.05
**Net proceeds per share (i. – j.):** $33.95
**Market price per share**

1) **At record date:** n/a
2) **At offering date (June 11, 2014):** $35.75
3) **One month after close of offerings (July 11, 2014):** $33.78

**Average market price during offering**

1) **Price per share:** $35.92 (average of opening and closing price on June 11, 2014)
2) **Rights per share – average value of rights:** n/a

**Latest reported earnings per share at time of offering:** $2.50 (2013 reported EPS); $2.25 - $2.55 (2014 full-year EPS guidance at time of offering)
**Latest reported dividends at time of offering:** $0.31 per share, declared on May 14, 2014 (an annualized rate of $1.24 per share)

Q. III-E-1 If a claim of the filing utility is based on utilization of the capital structure or capital costs of the parent company and system—consolidated—the reasons for this claim must be fully stated and supported.

A. III-E-1 The Company has not proposed the use of the capital structure or capital costs of the parent company in this filing.

Q. III-E-2 Regardless of the claim made, provide the capitalization data requested at Item III-A-2 for the parent company and for the system—consolidated.

A. III-E-2 Refer to the response to III-A-1.

Q. III-E-3 Provide the latest available balance sheet and income statement for the parent company and system – consolidated.

A. III-E-3

Parent

12/31/14 Balance Sheet – Refer to Attachment III-E-3(a)

12/31/14 Income Statement – Refer to Attachment III-E-3(b)

System (consolidated)

12/31/14 Balance Sheet – Refer to Attachment III-E-3(c)

12/31/14 Income Statement – Refer to Attachment III-E-3(d)

**Exelon Corporation and Subsidiary Companies**

**Schedule I – Condensed Financial Information of Parent (Exelon Corporate)**

**Condensed Balance Sheets**

| (In millions) | December 31, 2014 | December 31, 2013 |
|---|---|---|
| **ASSETS** | | |
| **Current assets** | | |
| Cash and cash equivalents | $ 879 | $ 3 |
| Accounts receivable, net | | |
| Other accounts receivable | 209 | 72 |
| Accounts receivable from affiliates | 24 | 22 |
| Deferred income taxes | 20 | 27 |
| Notes receivable from affiliates | 818 | 179 |
| Regulatory assets | 254 | 233 |
| Other | 22 | 1 |
| Total current assets | 2,226 | 537 |
| **Property, plant and equipment, net** | 54 | 57 |
| **Deferred debits and other assets** | | |
| Regulatory assets | 3,186 | 3,005 |
| Investments in affiliates | 26,670 | 26,390 |
| Deferred income taxes | 2,187 | 1,890 |
| Notes receivable from affiliates | 943 | 1,522 |
| Other | 172 | 17 |
| Total deferred debits and other assets | 33,158 | 32,824 |
| **Total assets** | $35,438 | $33,418 |

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, 2014 | 2013 |
|---|---|---|
| **LIABILITIES AND SHAREHOLDERS' EQUITY** | | |
| **Current liabilities** | | |
| Long-term debt due within one year | $ 1,409 | $ 10 |
| Accounts payable | 2 | 43 |
| Unamortized energy contract liabilities | — | 12 |
| Accrued expenses | 25 | 106 |
| Deferred income taxes | 60 | 26 |
| Regulatory liabilities | 51 | 2 |
| Other | 75 | 54 |
| Total current liabilities | 1,622 | 253 |
| **Long-term debt** | 2,841 | 3,033 |
| **Long-term debt to affiliate** | 182 | 176 |
| **Deferred credits and other liabilities** | | |
| Regulatory liabilities | 37 | 43 |
| Pension obligations | 7,638 | 6,444 |
| Non-pension postretirement benefit obligations | 16 | 393 |
| Deferred income taxes | 93 | 70 |
| Other | 398 | 271 |
| Total deferred credits and other liabilities | 8,182 | 7,221 |
| Total liabilities | 12,827 | 10,683 |
| **Commitments and contingencies** | | |
| **Shareholders' equity** | | |
| Common stock (No par value, 2,000 shares authorized, 860 and 857 shares outstanding at December 31, 2014 and 2013, respectively) | 16,709 | 16,741 |
| Treasury stock, at cost (35 shares held at December 31, 2014 and 2013, respectively) | (2,327) | (2,327) |
| Retained earnings | 10,910 | 10,358 |
| Accumulated other comprehensive loss, net | (2,684) | (2,040) |
| Total shareholders' equity | 22,608 | 22,732 |
| BGE preference stock not subject to mandatory redemption | 3 | 3 |
| **Total liabilities and shareholders' equity** | $35,438 | $33,418 |

See Notes to Financial Statements

**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, 2014 | 2013 | 2012 |
|---|---|---|---|
| **Operating expenses** | | | |
| Operating and maintenance | $ 9 | $ 9 | $ 201 |
| Operating and maintenance from affiliates | 38 | 34 | 72 |
| Other | 3 | 12 | 6 |
| Total operating expenses | 50 | 55 | 279 |
| **Operating loss** | (50) | (55) | (279) |
| **Other income and (deductions)** | | | |
| Interest expense, net | (237) | (116) | (153) |
| Equity in earnings of investments | 1,779 | 1,903 | 1,278 |
| Interest income from affiliates, net | 53 | 36 | 75 |
| Other, net | (2) | (78) | 7 |
| Total other income | 1,593 | 1,745 | 1,207 |
| **Income before income taxes** | 1,543 | 1,690 | 928 |
| **Income taxes (benefit)** | (80) | (29) | (232) |
| **Net income** | $1,623 | $1,719 | $1,160 |
| **Other comprehensive income (loss)** | | | |
| Pension and non-pension postretirement benefit plans: | | | |
| Prior service cost (benefit) reclassified to periodic costs | $ (30) | $ — | $ 1 |
| Actuarial loss reclassified to periodic cost | 147 | 208 | 168 |
| Transition obligation reclassified to periodic cost | — | — | 2 |
| Pension and non-pension postretirement benefit plan valuation adjustment | (497) | 669 | (371) |
| Unrealized loss on cash flow hedges | (148) | (248) | (120) |
| Unrealized gain on marketable securities | 1 | 2 | 2 |
| Unrealized gain on equity investments | 8 | 106 | 1 |
| Unrealized loss on foreign currency translation | (9) | (10) | — |
| Reversal of CENG equity method AOCI | (116) | — | — |
| **Other comprehensive income (loss)** | (644) | 727 | (317) |
| **Comprehensive income** | $ 979 | $2,446 | $ 843 |

See Notes to Financial Statements

**Exelon Corporation and Subsidiary Companies**

**Consolidated Balance Sheets**

| (In millions) | December 31, 2014 | 2013 |
|---|---|---|
| **ASSETS** | | |
| **Current assets** | | |
| Cash and cash equivalents | $ 1,878 | $ 1,609 |
| Restricted cash and cash equivalents | 271 | 167 |
| Accounts receivable, net | | |
| Customer | 3,482 | 2,981 |
| Other | 1,227 | 1,175 |
| Mark-to-market derivative assets | 1,279 | 727 |
| Unamortized energy contract assets | 254 | 374 |
| Inventories, net | | |
| Fossil fuel | 579 | 276 |
| Materials and supplies | 1,024 | 829 |
| Deferred income taxes | 244 | 573 |
| Regulatory assets | 847 | 760 |
| Assets held for sale | 147 | 14 |
| Other | 865 | 652 |
| Total current assets | 12,097 | 10,137 |
| **Property, plant and equipment, net** | 52,087 | 47,330 |
| **Deferred debits and other assets** | | |
| Regulatory assets | 6,076 | 5,910 |
| Nuclear decommissioning trust funds | 10,537 | 8,071 |
| Investments | 544 | 1,187 |
| Investment in CENG | — | 1,925 |
| Goodwill | 2,672 | 2,625 |
| Mark-to-market derivative assets | 773 | 607 |
| Unamortized energy contract assets | 549 | 710 |
| Pledged assets for Zion Station decommissioning | 319 | 458 |
| Other | 1,160 | 964 |
| Total deferred debits and other assets | 22,630 | 22,457 |
| **Total assets** (a) | $86,814 | $79,924 |

See the Combined Notes to Consolidated Financial Statements

**Exelon Corporation and Subsidiary Companies**

**Consolidated Balance Sheets**

| (In millions) | December 31, 2014 | 2013 |
|---|---|---|
| **LIABILITIES AND SHAREHOLDERS' EQUITY** | | |
| **Current liabilities** | | |
| Short-term borrowings | $ 460 | $ 341 |
| Long-term debt due within one year | 1,802 | 1,509 |
| Accounts payable | 3,048 | 2,484 |
| Accrued expenses | 1,539 | 1,633 |
| Payables to affiliates | 8 | 116 |
| Deferred income taxes | — | 40 |
| Regulatory liabilities | 310 | 327 |
| Mark-to-market derivative liabilities | 234 | 159 |
| Unamortized energy contract liabilities | 238 | 261 |
| Other | 1,123 | 858 |
| Total current liabilities | 8,762 | 7,728 |
| **Long-term debt** | 19,362 | 17,623 |
| **Long-term debt to financing trusts** | 648 | 648 |
| **Deferred credits and other liabilities** | | |
| Deferred income taxes and unamortized investment tax credits | 13,019 | 12,905 |
| Asset retirement obligations | 7,295 | 5,194 |
| Pension obligations | 3,366 | 1,876 |
| Non-pension postretirement benefit obligations | 1,742 | 2,190 |
| Spent nuclear fuel obligation | 1,021 | 1,021 |
| Regulatory liabilities | 4,550 | 4,388 |
| Mark-to-market derivative liabilities | 403 | 300 |
| Unamortized energy contract liabilities | 211 | 266 |
| Payable for Zion Station decommissioning | 155 | 305 |
| Other | 2,147 | 2,540 |
| Total deferred credits and other liabilities | 33,909 | 30,985 |
| Total liabilities [a] | 62,681 | 56,984 |
| **Commitments and contingencies** | | |
| **Shareholders' equity** | | |
| Common stock (No par value, 2,000 shares authorized, 860 and 857 shares outstanding at December 31, 2014 and 2013, respectively) | 16,709 | 16,741 |
| Treasury stock, at cost (35 shares held at December 31, 2014 and 2013) | (2,327) | (2,327) |
| Retained earnings | 10,910 | 10,358 |
| Accumulated other comprehensive loss, net | (2,684) | (2,040) |
| Total shareholders' equity | 22,608 | 22,732 |
| BGE preference stock not subject to mandatory redemption | 193 | 193 |
| Noncontrolling interest | 1,332 | 15 |
| Total equity | 24,133 | 22,940 |
| **Total liabilities and shareholders' equity** | $86,814 | $79,924 |

(a) Exelon's consolidated assets include $8,160 million and $1,755 million at December 31, 2014 and December 31, 2013, respectively, of certain VIEs that can only be used to settle the liabilities of the VIE. Exelon's consolidated liabilities include $2,723 million and $658 million at December 31, 2014 and December 31, 2013, respectively, of certain VIEs for which the VIE creditors do not have recourse to Exelon. See Note 2—Variable Interest Entities.

See the Combined Notes to Consolidated Financial Statements

## Exelon Corporation and Subsidiary Companies

## Consolidated Statements of Operations and Comprehensive Income

| (In millions, except per share data) | For the Years Ended December 31, 2014 | 2013 | 2012 |
|---|---|---|---|
| **Operating revenues** | $27,429 | $24,888 | $23,489 |
| **Operating expenses** | | | |
| Purchased power and fuel | 12,472 | 9,468 | 9,121 |
| Purchased power and fuel from affiliates | 531 | 1,256 | 1,036 |
| Operating and maintenance | 8,568 | 7,270 | 7,961 |
| Depreciation and amortization | 2,314 | 2,153 | 1,881 |
| Taxes other than income | 1,154 | 1,095 | 1,019 |
| Total operating expenses | 25,039 | 21,242 | 21,018 |
| **Equity in (losses) earnings of unconsolidated affiliates** | (20) | 10 | (91) |
| **Gain (loss) on sales of assets** | 437 | 13 | (7) |
| **Gain on consolidation and acquisition of businesses** | 289 | — | — |
| **Operating income** | 3,096 | 3,669 | 2,373 |
| **Other income and (deductions)** | | | |
| Interest expense, net | (1,024) | (1,315) | (891) |
| Interest expense to affiliates, net | (41) | (41) | (37) |
| Other, net | 455 | 460 | 353 |
| Total other income and (deductions) | (610) | (896) | (575) |
| **Income before income taxes** | 2,486 | 2,773 | 1,798 |
| **Income taxes** | 666 | 1,044 | 627 |
| **Net income** | 1,820 | 1,729 | 1,171 |
| **Net income attributable to noncontrolling interest, preferred security dividends and preference stock dividends** | 197 | 10 | 11 |
| **Net income attributable to common shareholders** | 1,623 | 1,719 | 1,160 |
| **Comprehensive income (loss), net of income taxes** | | | |
| Net income | 1,820 | 1,729 | 1,171 |
| **Other comprehensive income (loss), net of income taxes** | | | |
| Pension and non-pension postretirement benefit plans: | | | |
| Prior service (benefit) cost reclassified to periodic benefit cost | (30) | — | 1 |
| Actuarial loss reclassified to periodic cost | 147 | 208 | 168 |
| Transition obligation reclassified to periodic cost | — | — | 2 |
| Pension and non-pension postretirement benefit plan valuation adjustment | (497) | 669 | (371) |
| Unrealized loss on cash flow hedges | (148) | (248) | (120) |
| Unrealized gain on marketable securities | 1 | 2 | 2 |
| Unrealized gain on equity investments | 8 | 106 | 1 |
| Unrealized loss on foreign currency translation | (9) | (10) | — |
| Reversal of CENG equity method AOCI | (116) | — | — |
| Other comprehensive (loss) income | (644) | 727 | (317) |
| **Comprehensive income** | $ 1,176 | $ 2,456 | $ 854 |
| **Average shares of common stock outstanding:** | | | |
| Basic | 860 | 856 | 816 |
| Diluted | 864 | 860 | 819 |
| **Earnings per average common share:** | | | |
| Basic | $ 1.89 | $ 2.01 | $ 1.42 |
| Diluted | $ 1.88 | $ 2.00 | $ 1.42 |
| **Dividends per common share** | $ 1.24 | $ 1.46 | $ 2.10 |

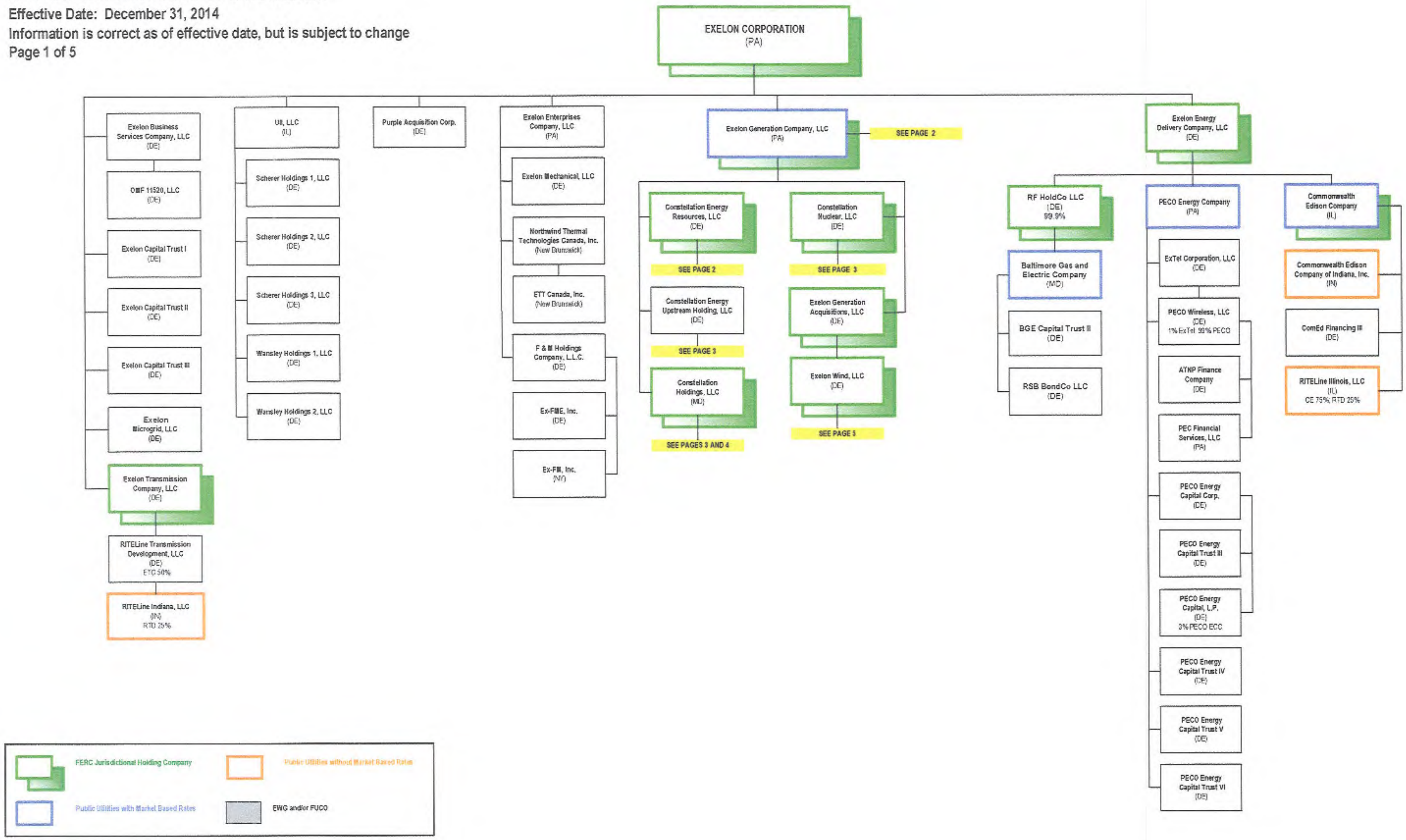
See the Combined Notes to Consolidated Financial Statements

Q. III-E- 4 Provide an organizational chart explaining the filing utility's corporate relationship to its affiliates - system structure.

A. III-E-4 Refer to Attachment III-E-4(a).

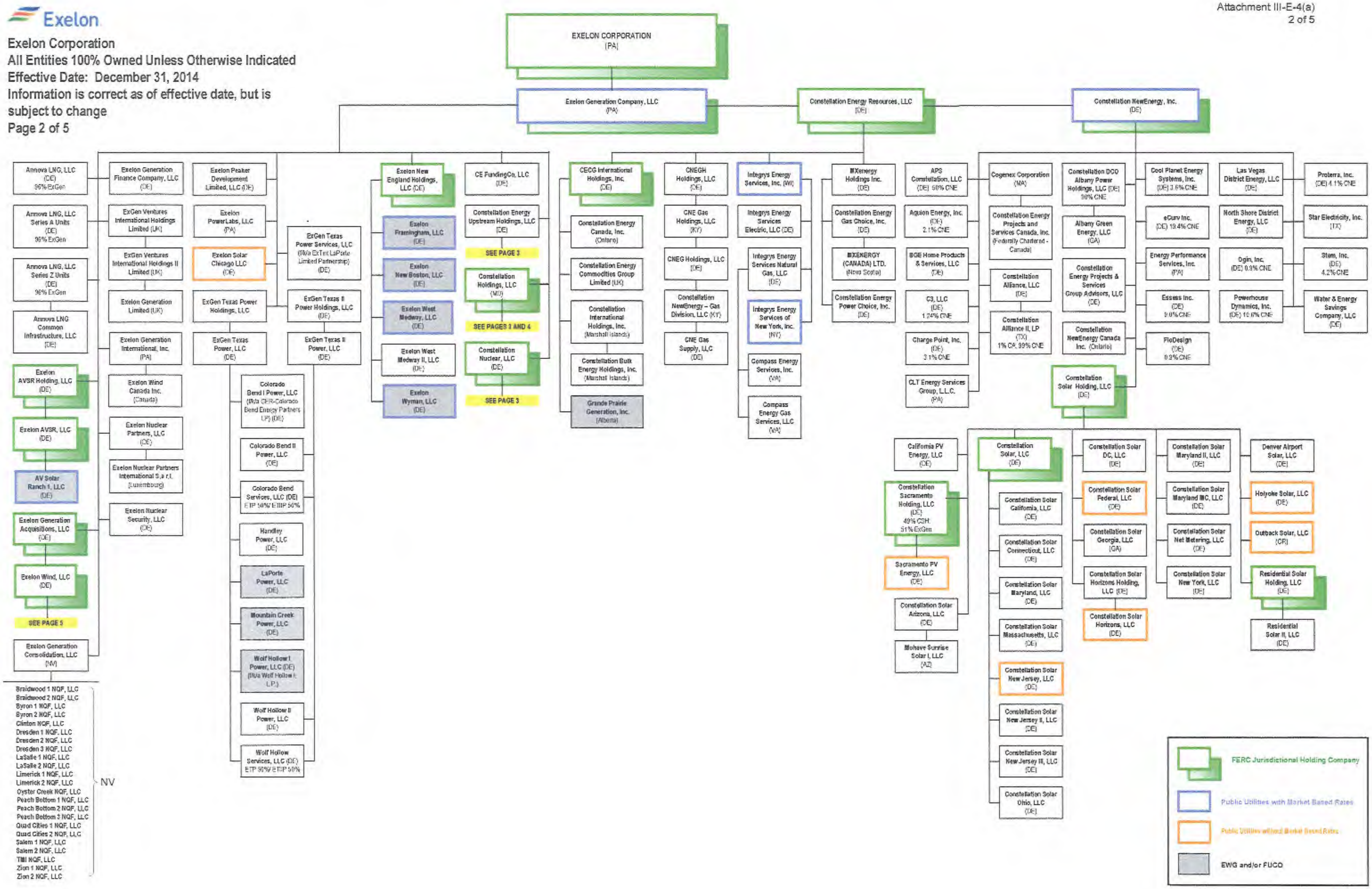
Exelon

Exelon Corporation
All Entities 100% Owned Unless Otherwise Indicated
Effective Date: December 31, 2014
Information is correct as of effective date, but is subject to change
Page 1 of 5



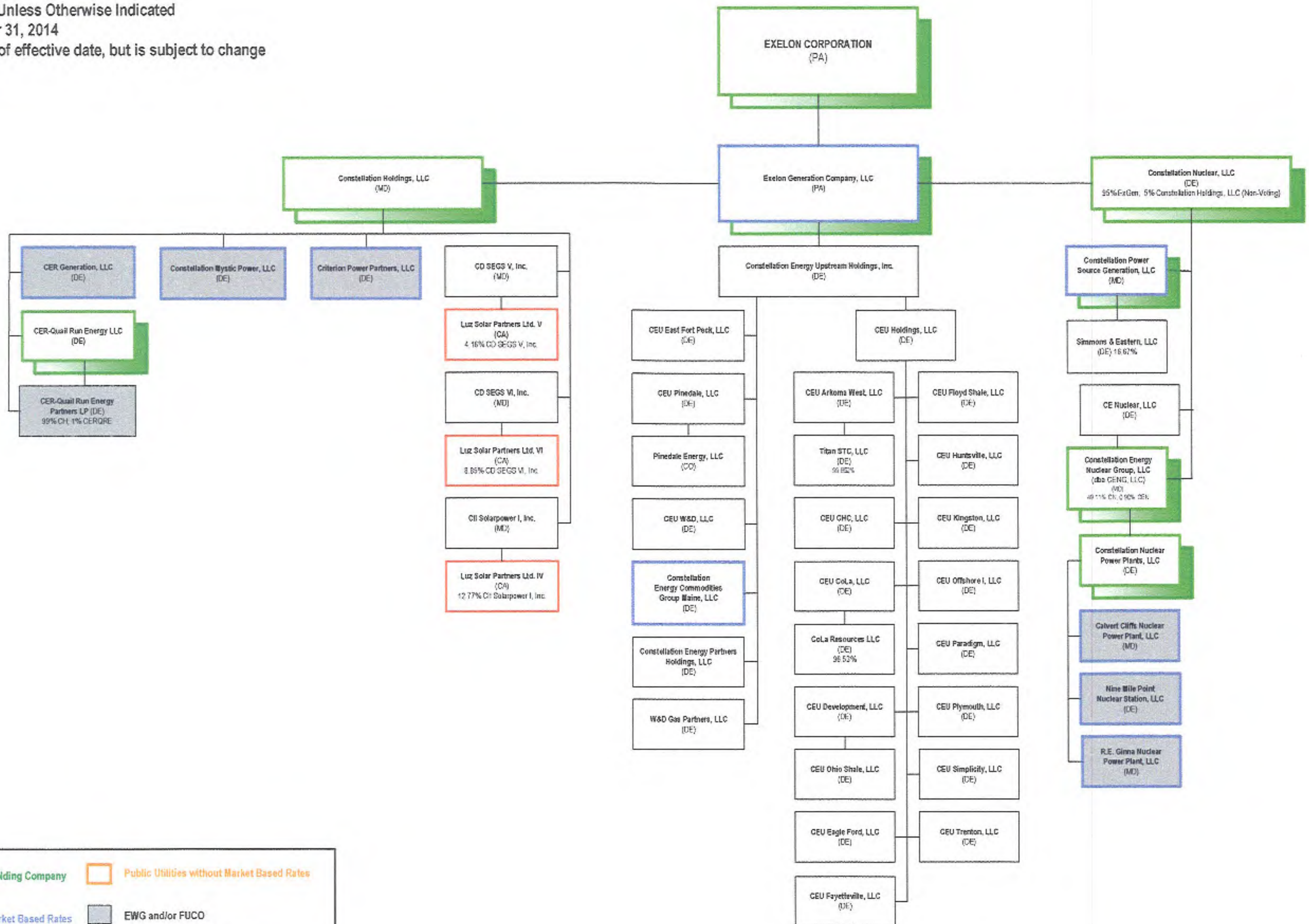
Exelon

**Exelon Corporation**
All Entities 100% Owned Unless Otherwise Indicated
Effective Date: December 31, 2014
Information is correct as of effective date, but is subject to change
Page 2 of 5



Exelon

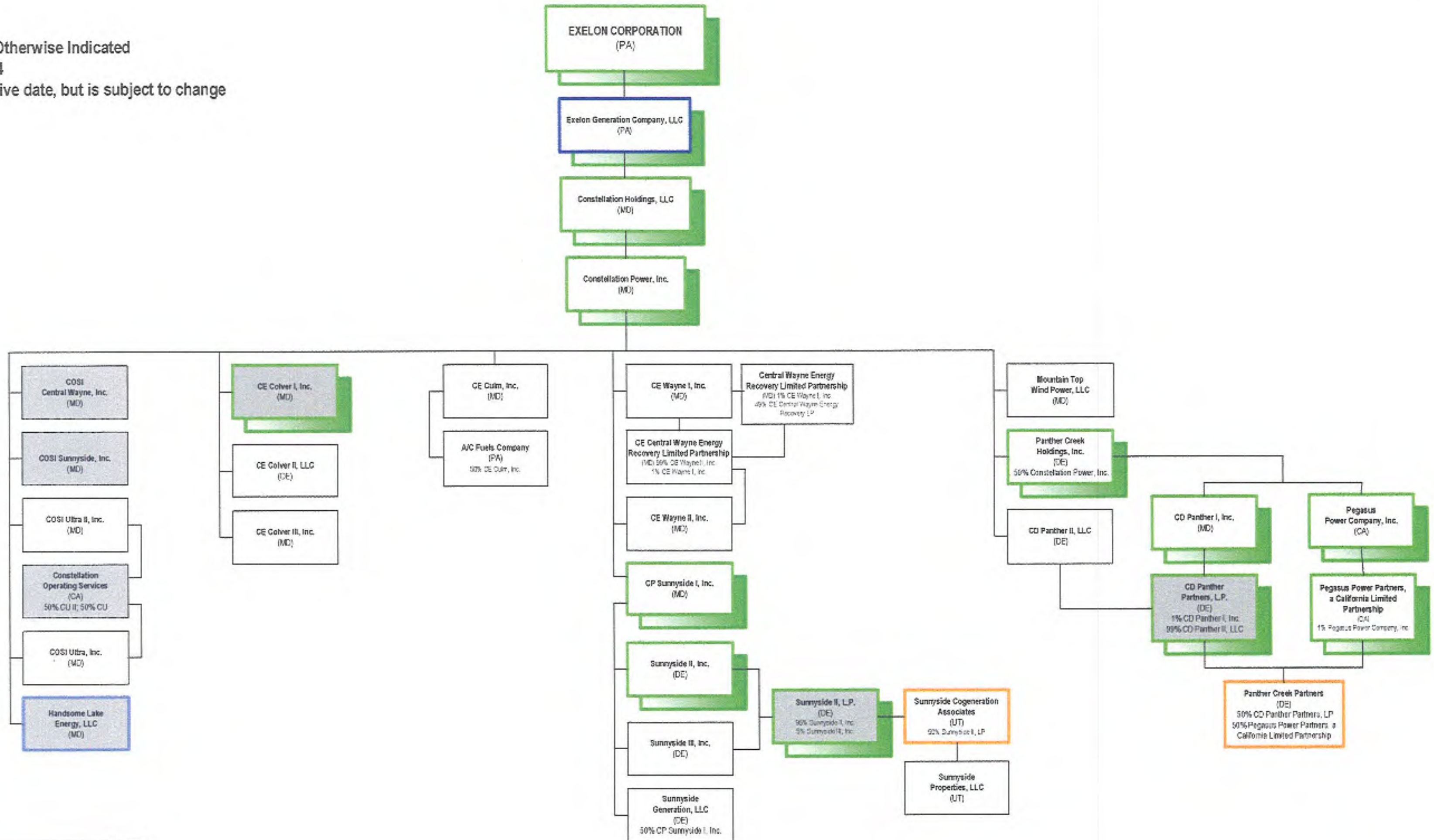
Exelon Corporation
All Entities 100% Owned Unless Otherwise Indicated
Effective date: December 31, 2014
Information is correct as of effective date, but is subject to change
Page 3 of 5




FERC Jurisdictional Holding Company
Public Utilities without Market Based Rates
Public Utilities with Market Based Rates
EWG and/or FUCO

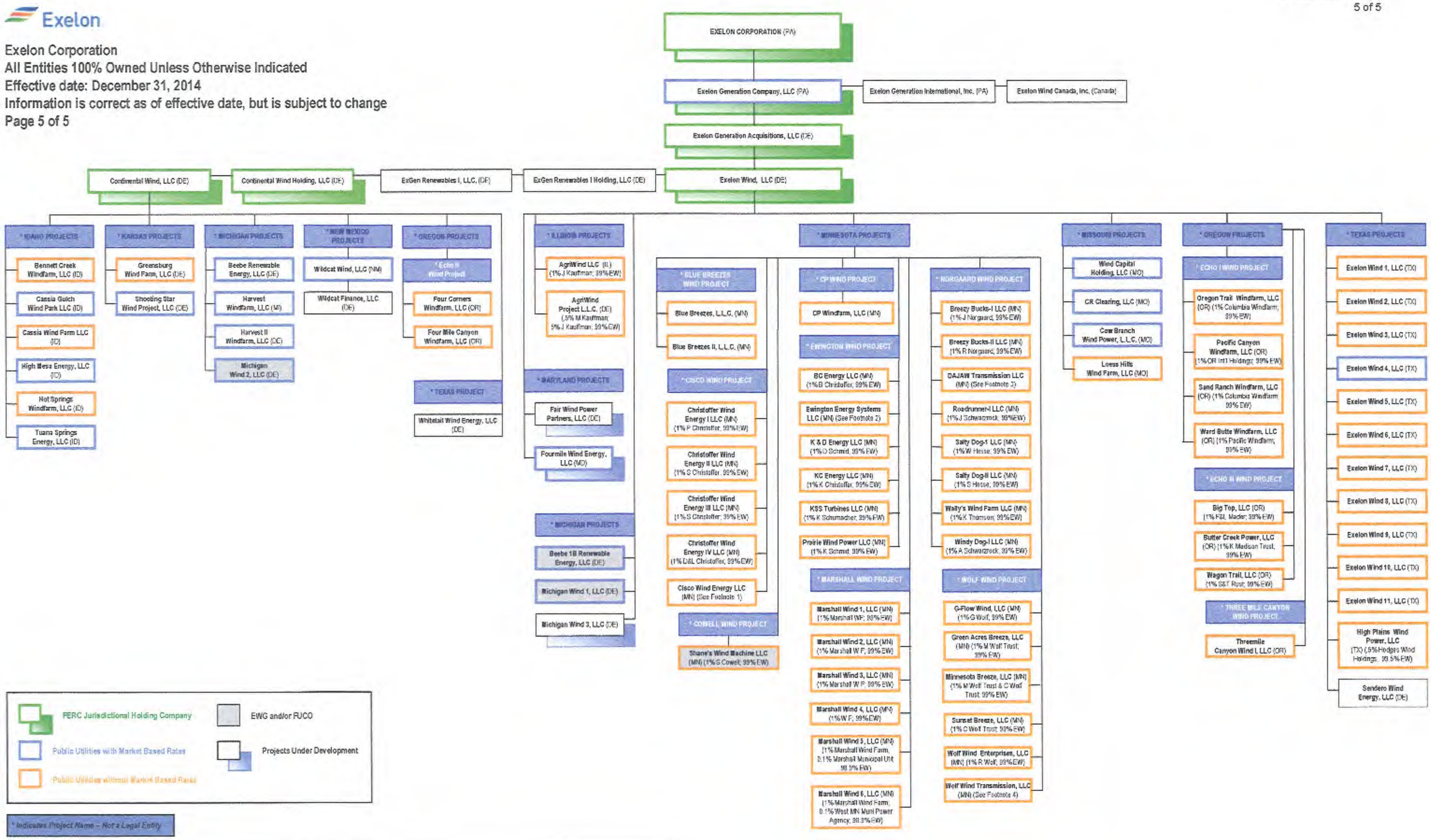
Exelon.

Exelon Corporation
All Entities 100% Owned Unless Otherwise Indicated
Effective date: December 31, 2014
Information is correct as of effective date, but is subject to change
Page 4 of 5




Exelon

Exelon Corporation
All Entities 100% Owned Unless Otherwise Indicated
Effective date: December 31, 2014
Information is correct as of effective date, but is subject to change
Page 5 of 5




* Indicates Project Name – Not a Legal Entity

**Footnotes:**
#1 Cisco Wind Energy, LLC: 25% owned by each of the following entities: Christoffer Wind Energy I LLC; Christoffer Wind Energy II LLC; Christoffer Wind Energy III LLC; and Christoffer Wind Energy IV LLC.
#2 Ewington Energy Systems LLC: 20% owned by each of the following entities: BC Energy LLC; K & D Energy LLC; KC Energy LLC; KSS Turbines LLC; and Prairie Wind Power LLC.
#3 DAJAW Transmission LLC: 14.29% owned by each of the following entities: Breezy Bucks-1 LLC; Breezy Bucks-II LLC; Roadrunner-I LLC; Salty Dog-I LLC; Salty Dog-II LLC; Wally's Wind Farm LLC; and Windy Dog-I LLC.
#4 Wolf Wind Transmission, LLC: 20% owned by each of the following entities: G-Flow Wind, LLC; Green Acres Breeze, LLC; Minnesota Breeze, LLC; Sunset Breeze, LLC; and Wolf Wind Enterprises, LLC.

Q. III-F-1 The latest available quarterly operating and financial report, annual report to the stockholders and prospectus shall be supplied for the utility and for the utility's parent, if the relationship exists.

A. III-F-1 Refer to SDR-ROR-1 attachments for all SEC Form 10-Qs issued within the last year and the most recent SEC Form 10-K. See Attachment III-F-1(a) for Exelon Corporation 2014 Annual Report. See Attachment III-F-1(b) for 2015 Exelon Corporation Proxy Statement.

# Exelon Corporation 2014 Annual Report

**Corporate Profile**

Exelon Corporation is the nation's leading competitive energy provider, with 2014 revenues of approximately $27.4 billion. Headquartered in Chicago, Exelon has operations and business activities in 47 states, the District of Columbia and Canada. Exelon is one of the largest competitive U.S. power generators, with approximately 32,750 megawatts of owned capacity comprising one of the nation's cleanest and lowest-cost power generation fleets. The company's Constellation business unit provides energy products and services to more than 2.5 million residential, public sector, and business customers. Exelon's utilities deliver electricity to more than 6.7 million customers in central Maryland (BGE), northern Illinois (ComEd) and southeastern Pennsylvania (PECO), and natural gas to 1.2 million customers through BGE and PECO. Exelon is headquartered in Chicago and trades on the NYSE under the ticker EXC.

**Corporate Headquarters**
Exelon Corporation
P.O. Box 805379
Chicago, IL 60680-5379

**Transfer Agent**
Wells Fargo Shareowner Services
800.626.8729

**Employee Stock Purchase Plan**
877.582.5113

**Employee Stock Options**
888.609.3534

**Investor Relations Voice Mailbox**
312.394.2345

**Shareholder Services Voice Mailbox**
312.394.8811

**Independent Public Accountants**
PricewaterhouseCoopers LLP

**Website**
www.exeloncorp.com

**Twitter**
@Exelon

**Stock Ticker**
EXC

**Shareholder Inquiries**
Exelon Corporation has appointed Wells Fargo Shareowner Services as its transfer agent, stock registrar, dividend disbursing agent and dividend reinvestment agent. Should you have questions concerning your registered shareholder account or the payment or reinvestment of your dividends, or if you wish to make a stock transaction or stock transfer, you may call shareowner services at Wells Fargo at the toll-free number shown to the left or access its website at www.shareowneronline.com.

Morgan Stanley administers the Employee Stock Purchase Plan (ESPP), employee stock options and other employee equity awards. Should you have any questions concerning your employee plan shares or wish to make a transaction, you may call the toll-free numbers shown to the left or access its website at www.benefitaccess.com.

The company had approximately 124,000 holders of record of its common stock as of Dec. 31, 2014.

The 2014 Form 10-K Annual Report to the Securities and Exchange Commission was filed on Feb. 13, 2015. To obtain a copy without charge, write to Bruce G. Wilson, Senior Vice President, Deputy General Counsel and Corporate Secretary, Exelon Corporation, Post Office Box 805379, Chicago, Illinois 60680-5379.

## TABLE OF CONTENTS

## 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. |
| *Antelope Valley, AVSR* | Antelope Valley Solar Ranch One |
| *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 |
| *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 |

**Other Terms and Abbreviations**

| | |
|---|---|
| *DC Circuit Court* | United States Court of Appeals for the District of Columbia Circuit |
| *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 |
| *EGR* | ExGen Renewables I, LLC |
| *EGS* | Electric Generation Supplier |
| *EGTP* | ExGen Texas Power, LLC |
| *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 |
| *GDP* | Gross Domestic Product |
| *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 |
| *Integrys* | Integrys Energy Services, Inc. |
| *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 |
| *LTIP* | Long-Term Incentive Plan |
| *MATS* | U.S. EPA Mercury and Air Toxics Standard 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. |

**Other Terms and Abbreviations**

| | |
|---|---|
| *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 |
| *NGS* | Natural Gas Supplier |
| *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 including the CENG units (Calvert Cliffs, Nine Mile Point, and R.E. Ginna),Clinton, Oyster Creek, Three Mile Island, Zion (a former ComEd unit), and portions of Peach Bottom (a former PECO unit) |
| *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 |
| *PPL* | PPL Holtwood, LLC |
| *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 including the former ComEd units (Braidwood, Byron, Dresden, LaSalle, Quad Cities) and the former PECO units (Limerick, Peach Bottom, Salem) |
| *RES* | Retail Electric Suppliers |
| *RFP* | Request for Proposal |
| *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 |

**Other Terms and Abbreviations**

| | |
|---|---|
| *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 |
| *SOA* | Society of Actuaries |
| *SOS* | Standard Offer Service |
| *SPP* | Southwest Power Pool |
| *Tax Relief Act of 2010* | Tax Relief, Unemployment Insurance Reauthorization and Job Creation Act of 2010 |
| *Upstream* | Natural gas and oil 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

This Report contains certain 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 Registrants include those factors discussed herein, including those factors discussed with respect to such Registrant discussed in (a) Management's Discussion and Analysis of Financial Condition and Results of Operations and (b) Financial Statements and Supplementary Data: Note 22; and (c) other factors discussed in 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.

## GENERAL DESCRIPTION OF OUR BUSINESS

### General

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 800-483-3220.

### Generation

Generation's integrated business consists of the generation, physical delivery and marketing of power across multiple geographical regions through its customer-facing business, Constellation, which sells electricity and natural gas to both wholesale and retail customers. Generation also sells renewable energy and other energy-related products and services, and engages in natural gas and oil exploration and production activities (Upstream). 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 electricity 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 electricity 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 electricity 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 natural 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—Segment Information of the Combined Notes to Consolidated Financial Statements for additional information on Exelon's operating segments.

**Pending Merger with Pepco Holdings, Inc.**

On April 29, 2014, Exelon and PHI signed an agreement and plan of merger (as subsequently amended and restated as of July 18, 2014) to combine the two companies in an all cash transaction. The resulting company will retain the Exelon name and be headquartered in Chicago. The merger is expected to be completed in the second or third quarter of 2015. See Note 4—Mergers, Acquisitions, and Dispositions of the Combined Notes to Consolidated Financial Statements for additional information on the pending 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. Constellation sells electricity and natural gas to both wholesale and retail customers. The retail sales include commercial, industrial and residential customers. 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. Generation's 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 challenging conditions emanating from competitive energy markets. Generation's customers include distribution utilities, municipalities, cooperatives, financial institutions, and commercial, industrial, governmental, and residential customers in competitive markets. Generation also sells renewable energy and other energy-related products and services, and engages in natural gas and oil exploration and production activities (Upstream).

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 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.

**Merger with Constellation Energy Group, Inc.**

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. Since the merger transaction, Generation includes the former Constellation generation and customer supply operations. See Note 4—Mergers, Acquisitions, and Dispositions of the Combined Notes to Consolidated Financial Statements for additional information on the Constellation merger.

**Constellation Energy Nuclear Group, Inc.**

Generation 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 a total of five nuclear generating facilities on three sites, Calvert Cliffs, R.E. 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.

Prior to April 1, 2014, Exelon and Generation accounted for their investment in CENG under the equity method of accounting. The transfer of the nuclear operating licenses and the execution of the NOSA on April 1, 2014, resulted in the derecognition of the equity method investment in CENG and the recording of all assets, liabilities and EDF's noncontrolling interest in CENG at fair value on Exelon's Consolidated Balance Sheets. Refer to Note 5—Investment in Constellation Energy Nuclear Group, LLC of the Combined Notes to Consolidated Financial Statements for further information regarding the integration transaction.

**Significant Acquisitions**

***Integrys Energy Services, Inc.*** On November 1, 2014, Generation acquired the competitive retail electric and natural gas business activities of Integrys Energy Group, Inc. through the purchase of all of the stock of its wholly owned subsidiary, Integrys Energy Services, Inc. (Integrys) for a purchase price of $332 million, including net working capital. The generation and solar asset businesses of Integrys are excluded from the transaction. See Note 4—Mergers, Acquisitions, and Dispositions of the Combined Notes to Consolidated Financial Statements for additional information on the above acquisition.

***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 242-MW solar project under development in northern Los Angeles County, California, from First Solar, Inc. The facility became fully operational in 2014. 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. Total capitalized costs for the facility incurred as of December 31, 2014 were approximately $1.1 billion.

***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 704 MWs.

**Significant Dispositions**

***Asset Divestitures.*** As of December 31, 2014, Generation sold or entered into agreements to divest certain generating assets with total expected pre-tax proceeds of $1.8 billion (after-tax proceeds of approximately $1.4 billion). The proceeds are expected to be used primarily to finance a portion of the acquisition of PHI.

***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 with Constellation Energy Group, Inc. for net proceeds of approximately $371 million, which resulted in a pre-tax impairment charge of $272 million.

See Note 4—Mergers, Acquisitions, and Dispositions and Note 8—Impairment of Long-Lived Assets of the Combined Notes to Consolidated Financial Statements for additional information.

***Generating Resources***

At December 31, 2014, the generating resources of Generation consisted of the following:

| Type of Capacity | MW |
|---|---|
| Owned generation assets (a)(b) | |
| Nuclear | 19,316 |
| Fossil (c) | 9,515 |
| Renewable (d) | 3,434 |
| Owned generation assets | 32,265 |
| Long-term power purchase contracts | 9,574 |
| Total generating resources | 41,839 |

(a) See "Fuel" for sources of fuels used in electric generation.
(b) Net generation capacity is stated at proportionate ownership share.
(c) Comprised primarily of natural gas generating assets. Excludes Quail Run, which was sold on January 21, 2015.
(d) Includes hydroelectric, wind, and solar generating assets.

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 35% 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 38% of capacity).
- New England represents the operations within ISO-NE covering the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont (approximately 7% 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 11% of capacity).
- Other Regions is an aggregate of regions not considered individually significant (approximately 6% of capacity).

See Note 24—Segment Information of the Combined Notes to Consolidated Financial Statements for additional information on revenues from external customers and revenues net of purchased power and fuel expense for each of Generation's reportable segments.

***Nuclear Facilities***

Generation has ownership interests in fourteen nuclear generating stations currently in service, consisting of 24 units with an aggregate of 19,316 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 and Generation's financial statements relative to its proportionate ownership interest in each unit. In addition, Generation owns a 50.01% interest, collectively, in the CENG generating stations (Calvert Cliff Nuclear Power Plant, Nine Mile Point Nuclear Station [excluding LIPA's 18% ownership interest in Nine Mile Point Unit 2] and R.E. Ginna) which are 100% consolidated on Exelon and Generation's financial statements as of April 1, 2014. See Note 5—Investment in Constellation Energy Nuclear Group, LLC of the Combined Notes to Consolidated Financial Statements for additional information.

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 2014, 2013, and 2012 electric supply (in GWh) generated from the nuclear generating facilities was 67%, 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 MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS for further discussion of Generation's electric supply sources.

***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 2014 and 2013, the nuclear generating facilities operated by Generation achieved capacity factors of 94.3% and 94.1%, respectively. The capacity factors reflect ownership percentage of stations operated by Generation and include CENG as of April 1, 2014. 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, 2014, the NRC categorized Calvert Cliffs unit 2, Clinton, Limerick units 1 and 2, and Oyster Creek 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, 2014, which is the highest performance band. 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 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 Unit 1, Calvert Cliffs Units 1 and 2, Nine Mile Point Units 1 and 2, R.E. Ginna Unit 1, Three Mile Island Unit 1 and Limerick Units 1 and 2. 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 |
| Calvert Cliffs [(c)] | 1 | 1975 | 2034 |
| | 2 | 1977 | 2036 |
| Clinton | 1 | 1987 | 2026 |
| Dresden [(c)] | 2 | 1970 | 2029 |
| | 3 | 1971 | 2031 |
| LaSalle [(d)] | 1 | 1984 | 2022 |
| | 2 | 1984 | 2023 |
| Limerick [(c)] | 1 | 1986 | 2044 |
| | 2 | 1990 | 2049 |
| Nine Mile Point [(c)] | 1 | 1969 | 2029 |
| | 2 | 1988 | 2046 |
| 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 |
| R.E. Ginna [(c)] | 1 | 1970 | 2029 |
| 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) In May 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 renewed operating licenses.
(d) In December 2014, Generation submitted applications to the NRC to extend the operating licenses of LaSalle 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 currently has license renewal applications pending for Braidwood Units 1 and 2, Byron Units 1 and 2, and LaSalle Units 1 and 2. Generation has advised the NRC that any license renewal application for Clinton would not be filed until the first quarter of 2021. 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 operating 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 393 MWs of new nuclear generation at a cost of $1,193 million, which has been capitalized to property, plant and equipment on Exelon's Consolidated Balance Sheets. At December 31, 2014, Generation has capitalized $122 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 139 MWs of new nuclear generation that is in the installation phase at one nuclear station, Peach Bottom in Pennsylvania. The remaining spend associated with this project is expected to be approximately $125 million through the end of 2016. Generation believes that it is probable that this project 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, 2014, Generation had approximately 73,800 SNF assemblies (18,300 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—Asset Retirement Obligations 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 are anticipated to 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 losing full core offload capability in 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—Commitments and Contingencies 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 ships its Class A LLRW, which represents 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 utilizes on-site storage capacity at its Peach Bottom and LaSalle stations to store Class B and Class C LLRW for all stations in Generation's nuclear fleet, as approved by the NRC. Generation has a contract through 2032 to ship Class B and Class C LLRW to a disposal facility in Texas. The agreement provides for disposal of all current Class B and Class C LLRW currently stored at the Peach Bottom and LaSalle stations as well as the Class B and Class C LLRW generated during the term of the agreement. However, because the production of LLRW from Generation's nuclear fleet will exceed the capacity at the Texas site (3.9 million curies for 15 years beginning in 2012), Generation will still be required to utilize on-site storage at its Peach Bottom and LaSalle stations for Class B and Class C LLRW. Generation currently has enough storage capacity to store all Class B and C LLRW for the life of all stations in Generation's nuclear fleet. 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—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for details.

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 MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS—Exelon Corporation, Executive Overview; 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 Note 3—Regulatory Matters, Note 11—Fair Value of Financial Assets and Liabilities and Note 15—Asset Retirement Obligations 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 liabilities to decommission Dresden Unit 1 and Peach Bottom Unit 1 as of December 31, 2014 were $188 million and $111 million, respectively. As of December 31, 2014, NDT funds set aside to pay for these obligations were $459 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—Asset Retirement Obligations of the Combined Notes to Consolidated Financial Statements for additional information regarding Zion Station Decommissioning and see Note 2—Variable Interest Entities 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 12,949 MW of capacity in fossil and renewable generating facilities currently in service (excluding Quail Run, which was sold on January 21, 2015). Generation wholly owns all of its fossil and renewable generating stations, with the exception of: (1) jointly owned facilities that include Wyman; (2) an ownership interest through an equity method investment in Sunnyside; and (3) certain wind project entities with minority interest owners, see Note 2—Variable Interest Entities 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 LaPorte, Sunnyside and Wyman, which are operated by third parties. See Note 4—Mergers, Acquisitions, and Dispositions of the Combined Notes to Consolidated Financial Statements for additional information relating to the sale of the Quail Run generating facility. In 2014 and 2013, electric supply (in GWh) generated from owned fossil and renewable generating facilities was 13% and 15%, 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 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 Conowingo Hydroelectric Project (Conowingo) and the Muddy Run Pumped Storage Facility Project (Muddy Run), respectively. Based on the FERC procedural schedule, the FERC licensing process was not completed prior to the expiration of Muddy Run's license on August 31, 2014, and the expiration of Conowingo's license on September 1, 2014. FERC is required to issue annual licenses for the facilities until the new licenses are issued. On September 10, 2014, FERC issued annual licenses for Conowingo and Muddy Run, effective as of the expiration of the previous licenses. If FERC does not issue new licenses prior to the expiration of annual licenses, the annual licenses will renew automatically. The stations are currently being depreciated over their estimated useful lives, which includes the license renewal period. Refer to Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements 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, unless required by financing agreements. 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.

### *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, 2014:

| Region | Number of Agreements | Expiration Dates | Capacity (MW) |
|---|---|---|---|
| Mid-Atlantic | 19 | 2015 - 2032 | 860 |
| Midwest | 7 | 2015 - 2022 | 1,734 |
| New England | 15 | 2015 - 2020 | 1,401 |
| ERCOT | 5 | 2020 - 2031 | 1,534 |
| Other Regions | 15 | 2015 - 2030 | 4,045 |
| Total | 61 | | 9,574 |

| | 2015 | 2016 | 2017 | 2018 | 2019 |
|---|---|---|---|---|---|
| Capacity Expiring (MW) | 2,726 | 73 | 1,965 | 101 | 631 |

### *Fuel*

The following table shows sources of electric supply in GWh for 2014 and 2013:

| | Source of Electric Supply | |
|---|---|---|
| | 2014 | 2013 |
| Nuclear [(a)] | 166,454 | 142,126 |
| Purchases—non-trading portfolio [(b)] | 48,200 | 69,791 |
| Fossil (primarily natural gas) | 26,324 | 30,785 |
| Renewable [(c)] | 6,429 | 6,420 |
| Total supply | 247,407 | 249,122 |

(a) Includes the proportionate share of output where Generation has an undivided ownership interest in jointly-owned generating plants and includes the total output of plants that are fully consolidated (e.g., CENG). Nuclear generation for 2014 and 2013 includes physical volumes of 25,053 GWh and 0 GWh, respectively, for CENG.
(b) Purchased power for 2014 and 2013 includes physical volumes of 5,346 GWh and 24,232 GWh, respectively, as a result of the PPA with CENG. On April 1, 2014, Generation assumed operational control of CENG's nuclear fleet. As a result, 100% of CENG volumes are included in nuclear generation.
(c) Includes hydroelectric, wind, and solar generating assets.

The fuel costs per MWh 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 2015. All of Generation's enrichment requirements have been contracted through 2020. 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 MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS, Critical Accounting Policies and Estimates and Note 12—Derivative Financial Instruments 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, including tolling agreements, 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 also buy power to meet the energy demand of its customers. 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. Additionally, Generation is involved in the development, exploration, and harvesting of oil, natural gas and natural gas liquids properties (Upstream).

***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 commodity price risk in 2015 and beyond for portions of its electricity portfolio that are unhedged. Generation has been and will continue to be proactive in using hedging strategies to mitigate this risk in subsequent years. This strategy has not changed as a result of recent and pending asset divestitures. As of December 31, 2014, the percentage of expected generation hedged for the major reportable segments was 93%-96%, 61%-64% and 31%-34% for 2015, 2016, and 2017, respectively. The percentage of expected generation hedged is the amount of equivalent sales divided by the expected generation (which reflects the divestiture impact of Quail Run). Expected generation is the volume of energy that best represents our commodity position in energy markets from owned or contracted for capacity based upon a simulated dispatch model that makes assumptions regarding future market conditions, which are calibrated to market quotes for power, fuel, load following products, and options. 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. The corporate risk management group and Exelon's RMC monitor the financial risks of the wholesale and retail power marketing activities. 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 proprietary 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. See QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK for additional information.

At December 31, 2014, 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) | Total |
|---|---|---|---|---|
| 2015 | $ 418 | $152 | $ 20 | $ 590 |
| 2016 | 283 | 228 | 15 | 526 |
| 2017 | 222 | 121 | 15 | 358 |
| 2018 | 112 | 29 | 16 | 157 |
| 2019 | 117 | 5 | 16 | 138 |
| Thereafter | 279 | 1 | 35 | 315 |
| Total | $1,431 | $536 | $117 | $2,084 |

(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, 2014, net of fixed capacity payments expected to be received ("Capacity offsets") by Generation under contracts to resell such acquired capacity to third parties under long-term capacity sale contracts. As of December 31, 2014, capacity offsets were $132 million, $133 million, $136 million, $137 million,$138 million, and $591 million for years 2015, 2016, 2017, 2018, 2019, and thereafter, respectively. 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.

### *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 2015 are as follows:

| (in millions) | |
|---|---|
| Nuclear fuel (a) | $1,250 |
| Production plant | 1,800 |
| Renewable energy projects | 225 |
| Maryland commitments | 225 |
| Other | 125 |
| Total | $3,625 |

(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 electricity 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 2015 to 2066. ComEd anticipates working with the appropriate governmental bodies 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 16,515 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 number of retail customers participating in customer choice programs was 2,426,921, 2,630,185 and 1,627,150 at December 31, 2014, 2013 and 2012, respectively, representing 63.0%, 68% and 43% of total retail customers, respectively. Retail energy purchased from competitive electric generation suppliers represented 80%, 81% and 65% of ComEd's retail kWh sales for the years ended December 31, 2014, 2013 and 2012, respectively.

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 or ComEd's financial position. 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 Note 24—Segment Information of the Combined Notes to Consolidated Financial Statements for additional information on revenues from external customers, net income and total assets.

Under Illinois law, ComEd is required to deliver electricity to all customers within ComEd's service territory. 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.

EIMA is scheduled to sunset, ending ComEd's performance based rate formula and investment commitment, at December 31, 2017, unless approved to continue through 2022 by the Illinois General Assembly. During the fourth quarter of 2014, the Illinois House and Senate each passed House Bill 3975 which extends the date of the EIMA sunset from 2017 to 2019. The bill was presented to the Governor on February 11, 2015. The Governor can either act on the bill or, after 60 days, the bill will automatically become law.

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. ComEd's allowed rate of return on common equity is the annual average rate on 30-year treasury notes plus 580 basis points, subject to a (collar) of plus or minus 50 basis points. The collar, therefore limits favorable and unfavorable impacts of weather and load on distribution revenue. In addition, ComEd's allowed 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—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

*Procurement-Related Proceedings.* ComEd is permitted to recover its electricity procurement costs from retail customers without mark-up. 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. Charges incurred for electric supply procured through contracts with Generation are included in Purchased power from affiliates on ComEd's Statement of operations and Comprehensive Income.

See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on ComEd's procurement plans.

*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***

*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 June 11, 2014, the ICC approved ComEd's request to accelerate the deployment, which allows for the installation of more than four million smart meters throughout ComEd's service territory by 2018, three years in advance of the originally scheduled 2021 completion date. To date, nearly 550,000 smart meters have been installed in the Chicago area by ComEd.

*Energy Efficiency Programs.* 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 January 2014, the ICC approved ComEd's third three-year Energy Efficiency and Demand Response Plan covering the period June 2014 through May 2017. The plans are designed to meet Illinois' energy efficiency and demand response goals through May 2017, 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 through 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 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.

***Construction Budget***

ComEd's business is capital intensive and requires significant investments, primarily in electricity transmission and electricity distribution facilities, to ensure the adequate capacity, reliability and efficiency of its system. Such investments include capital program and modernization pursuant to EIMA, and transmission upgrades and expansion including the Grand Prairie Gateway Transmission Line project, and PJM's RTEP. ComEd's most recent estimate of capital expenditures for electric plant additions and improvements for 2015 is $2,200 million.

See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional details. See 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 electricity 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 4.0 million, including approximately 1.6 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 506,000 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," with all of such 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 7,166 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, 2014, there were 101 competitive electric generation suppliers serving PECO customers. At December 31, 2014, the number of retail customers purchasing energy from a competitive electric generation supplier was 546,900 representing approximately 34% of total retail customers. Retail deliveries purchased from competitive electric generation suppliers represented approximately 70% of PECO's retail kWh sales for the year ended December 31, 2014. 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 PECO's electric revenue net of purchased power expense or 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 revenue or purchased 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.

See Note 24—Segment Information of the Combined Notes to Consolidated Financial Statements for additional information on revenues from external customers, net income and total assets.

*Procurement-Related Proceedings.* PECO's electric supply for its customers is procured through contracts executed in accordance with its PAPUC-approved DSP Programs.

On October 12, 2012, the PAPUC approved PECO's second DSP Program, which was filed with the PAPUC in January 2012. The plan outlined how PECO purchased electric supply for default service customers from June 1, 2013 through May 31, 2015. Pursuant to the second DSP Program, PECO procured 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. PECO entered into contracts with PAPUC approved bidders, including Generation, for its five competitive procurements. 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. By Order entered on January 24, 2014, the PAPUC approved PECO's plan, with modifications, to make CAP shopping available beginning April 15, 2014. On March 20, 2014, low-income advocacy groups filed an appeal and emergency request for a stay with the Pennsylvania Commonwealth Court, claiming that the PAPUC-ordered CAP Shopping plan does not contain sufficient protections for low-income customers. On March 28, 2014, the Commonwealth Court issued the requested stay, pending a full review of the appeal. Pending the Commonwealth Court's review, PECO will not implement CAP Shopping. The Commonwealth Court's decision is expected in 2015.

On March 10, 2014, PECO filed its third DSP Program with the PAPUC. The program has a 24-month term from June 1, 2015 through May 31, 2017, and complies with electric generation procurement guidelines set forth in Act 129. On August 28, 2014, PECO filed a Joint Petition for Partial Settlement, which affirmed PECO's procurement plan for residential and small commercial customers. On December 4, 2014, the PAPUC approved PECO's third DSP Program, as modified by the Joint Petition for Partial Settlement, without modification or limitation. Separate from the Joint Petition for Partial Settlement, the PAPUC also approved other items related to the program. The plan outlines how PECO will purchase electric supply for default service customers. PECO will procure electric supply through four competitive procurements for fixed price full requirements contracts of two years or less for the residential classes and small and medium commercial classes and spot market price full requirement contracts for the large commercial and industrial class load.

See Note 3—Regulatory Matters 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 was awarded $200 million, the maximum grant allowable under the program, for its SGIG project—Smart Future Greater Philadelphia. As of December 31, 2014, PECO has received all of the $200 million, including $4 million for sub-recipients, in reimbursements. The SGIG funds have been used by PECO to offset the total impact to ratepayers of the smart meter deployment required by Act 129. 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. Under PECO's universal deployment plan, PECO will deploy all of the 1.7 million electric smart meters on an accelerated basis by the second quarter of 2015. In total, PECO currently expects to spend up to $583 million and $155 million on its smart meter and smart grid infrastructure, respectively, before considering the $200 million SGIG funds. As of December 31, 2014, PECO has spent $540 million and $119 million on smart meter and smart grid infrastructure, respectively, not including the DOE reimbursements received.

See Note 3—Regulatory Matters 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 set forth how PECO would meet the required reduction targets established by Act 129's EE&C provisions, which included a 3.0% 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. On March 20, 2014, the PAPUC issued its final report stating that PECO was in full compliance with all Phase I targets.

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 with a three-year cumulative consumption reduction target of 1,125,852 MWh.

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. In its February 20, 2014 Final Order, the PAPUC stated that it does not expect to make a decision as to whether it will prescribe additional demand response obligations until 2015. Any decision reached would affect PECO's EE&C Plan subsequent to its Phase II Plan.

On February 28, 2014, 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, 2014 to May 31, 2016. PECO proposed to fund the estimated $10 million annual costs of the program by modifying incentive levels for other Phase II programs. The costs of the DLC program will be recovered through PECO's Energy Efficiency Program Charge along with other Phase II Plan costs. The PAPUC granted PECO's Petition in an Order that became final on May 5, 2014.

*Pennsylvania Retail Electricity Market.* The extreme weather experienced in early 2014 resulted in increased commodity costs causing certain shopping customers to receive unexpectedly high utility bills. In response to a significant number of customer complaints throughout Pennsylvania, on April 3, 2014, the PAPUC unanimously voted to adopt two rulemaking orders to address the issue. The first rulemaking order requires electric generation suppliers to provide more consumer education regarding their contracts. The second rulemaking order requires electric distribution companies to enable customers to switch suppliers within three business days (known as accelerated switching). The improved customer education and accelerated switching were to be in place within 30 days and six months of approval of the orders, respectively. The orders became final on June 14, 2014. On December 4, 2014, the PAPUC approved PECO's implementation plan (known as Bill on Supplier Switch), allowing PECO to implement accelerated switching by the December 15, 2014 deadline.

See Note 3—Regulatory Matters 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, 2014, the number of retail customers purchasing natural gas from a competitive natural gas supplier was 78,400, representing approximately 15% of total retail customers. Retail deliveries purchased from competitive natural gas suppliers represented approximately 22% of PECO's mmcf sales for the year ended December 31, 2014. PECO provides distribution, billing, metering, installation, maintenance and emergency response services at regulated rates to all its customers in its service territory.

*Procurement-Related 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 32 million dekatherms. Peak natural gas is provided by PECO's liquefied natural gas (LNG) facility and propane-air plant which provide 1.2 billion cubic feet and 181,441 dekatherms, respectively, on an annual basis. PECO also has under contract 21 million dekatherms of underground storage through service agreements. Natural gas from underground storage represents approximately 29% of PECO's 2014-2015 heating season planned supplies.

*Gas Main Extension Program.* On November 6, 2014, PECO filed a plan with the PAPUC requesting approval of three initiatives to provide more incentives to customers interested in switching to natural gas service. If approved, local customers would pay significantly less initially to have natural gas installed at their homes and businesses.

See Note 3—Regulatory Matters 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. PECO's most recent estimate of capital expenditures for plant additions and improvements for 2015 is $550 million, which includes RTEP projects and capital expenditures related to the smart meter and smart grid project.

See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional details. See MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS, Liquidity and Capital Resources for further information.

**BGE**

BGE is engaged principally in the purchase and regulated retail sale of electricity and the provision of electricity 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 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 nonexclusive 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 commercial 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 are 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 BGE's electric revenue net of purchased power expense or financial position. At December 31, 2014, there were 59 competitive electric generation suppliers serving BGE customers. At December 31, 2014, the number of retail customers purchasing energy from a competitive electric generation supplier was approximately 364,000, representing 29% of total retail customers. Retail deliveries purchased from competitive electric generation suppliers represented approximately 60% of BGE's retail kWh sales for the year ended December 31, 2014.

See Note 24—Segment Information of the Combined Notes to Consolidated Financial Statements for additional information on revenues from external customers, net income and total assets.

*Procurement Related Proceedings.* 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. Charges incurred for electric supply procured through contracts with Generation are included in Purchased power from affiliates on BGE's Statement of Operations and Comprehensive Income.

See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on BGE's procurement plan.

*Electric Distribution Rate Case.* On July 2, 2014, and as amended on September 15, 2014, BGE filed for an electric base rate increase with the MDPSC, ultimately requesting an increase of $99 million. On October 17, 2014, BGE filed with the MDPSC a unanimous settlement agreement (the Settlement Agreement) reached with all parties to the case under which it would receive an increase of $22 million in electric base rates. The Settlement Agreement establishes new depreciation rates which have the effect of decreasing annual electric depreciation expense by approximately $22 million. On December 4, 2014, the Public Utility Law Judge issued a proposed order approving the Settlement Agreement without modification, which became a final order on December 12, 2014. The approved electric distribution rate became effective for services rendered on or after December 15, 2014.

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

***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 was awarded $200 million, the maximum grant allowable under the program, to support its Smart Grid, Peak Rewards and CC&B initiatives, of which BGE had been fully reimbursed for as of December 31, 2013. The SGIG funding significantly reduced the rate impact of those investments on BGE customers.

See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information regarding BGE's Smart Meter Programs.

*Energy Efficiency Programs.* BGE's energy efficiency programs include a lighting program, retrofit programs, incentives for energy efficient new homes, rebates for heating and cooling systems, energy audits, an energy efficient appliance rebate and trade-in program, customer incentives for non-profit, educational, governmental and business customers, energy management programs and bill credits to help residential customers reduce energy demand during peak periods. The MDPSC initially approved a full portfolio of conservation programs in 2008 as well as a customer surcharge to recover the associated costs in 2009. This customer surcharge is updated annually. In December 2011, the MDPSC approved BGE's conservation programs for implementation in 2012 through 2014. On December 23, 2014, the MDPSC approved BGE's proposal for the 2015-2017 programs with minor modifications.

See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information regarding BGE's Energy Efficiency Programs.

***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. 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.

Customer choice program activity affects revenue collected from customers related to supplied natural gas; however, that activity has minimal impact on BGE's gas revenue net of purchased power expense or financial position. At December 31, 2014, there were 40 competitive natural gas suppliers serving BGE customers. At December 31, 2014, the number of retail customers purchasing fuel from a competitive natural gas supplier was approximately 161,000 representing 25% of total retail customers. Retail deliveries purchased from competitive natural gas suppliers represented approximately 53% of BGE's retail mmcf sales for the year ended December 31, 2014.

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 354 mmcf per day.

BGE's current maximum storage entitlements are 312 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 Case.* On July 2, 2014, and as amended on September 15, 2014, BGE filed for a gas base rate increase with the MDPSC, ultimately requesting an increase of $68 million. On October 17, 2014, BGE filed with the MDPSC the Settlement Agreement reached with all parties to the case under which it would receive an increase of $38 million in gas base rates. The Settlement Agreement establishes new depreciation rates which have the effect of increasing annual gas depreciation expense by approximately $2 million. On December 14, 2014, the Public Utility Law Judge issued a proposed order approving the Settlement Agreement without modification, which became a final order on December 12, 2014. The approved gas distribution rate became effective for services rendered on or after December 15, 2014.

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

***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 BGE's most recent estimate of capital expenditures for plant additions and improvements for 2015 is approximately $700 million.

See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional details. See MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS, Liquidity and Capital Resources for further information.

**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 PECO's 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—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information regarding transmission services.

**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, 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.

See MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS for additional information regarding clean air regulation in the forms of the CSAPR, 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. 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.

***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 October 14, 2014, the U.S. EPA's final Section 316(b) rule became effective. The rule requires that a series of studies and analyses be performed to determine the best technology available, followed by an implementation period. The timing of the various requirements for each facility is related to the status of its current NPDES permit and the subsequent renewal period. There is no fixed compliance schedule, as this is left to the discretion of the state permitting director.

The rule does not require closed-cycle cooling (e.g., cooling towers) as the best technology available to address impingement and entrainment of aquatic life at a facility's cooling water intake structure. The rule provides the state permitting director with significant 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 rule also provides a number of flexible compliance options to reduce impingement (trapping aquatic life on screens) mortality, which likely will be accomplished by the installation of screens or other technology at the intake. A number of concerns raised by the electric generation industry about the proposed rule were resolved favorably in the final rule.

Until the compliance requirements are determined by the applicable state permitting director on a site-specific basis for each plant, Generation cannot estimate the effect that compliance with the rule will have on the operation of its and CENG's generating facilities and its future results of operations, cash flows capital expenditures, and financial position. Should a state permitting director determine that a facility must install cooling towers to comply with the rule, that facility's economic viability would be called into question. However, the likely impact of the rule has been significantly decreased since the final rule does not mandate cooling towers as a national standard, and the state permitting director is required to apply a cost-benefit test and can take into consideration site-specific factors.

***New York Facilities.*** In July 2011, the New York Department of Environmental Conservation (DEC) issued a policy regarding the best available technology for cooling water intake structures. Through its policy, the DEC established closed-cycle cooling or its equivalent as the performance goal for all existing facilities, but also provided that the DEC will select a feasible technology whose costs are not wholly disproportionate to the environmental benefits to be gained and allows for a site-specific determination where the entrainment performance goal cannot be achieved. Each of CENG's New York facilities received renewals of their SPDES permits in 2014.

***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. However, it is unknown at this time whether implementation of the final EPA rule will result in a requirement to install closed cycle cooling at Salem.

***Solid and Hazardous Waste***

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—Commitments and Contingencies 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 2015 at Exelon for compliance with environmental remediation related to contamination at former MGP sites is expected to total $35 million, consisting of $29 million, $6 million and $0 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, 2014, 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—Regulatory Matters and 22—Commitments and Contingencies 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 positions.

***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 issued in 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 (CO2e) 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; CO2, methane and nitrous oxide are all emitted in this process, with CO2 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 2014, 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 (SF6) 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. At COP 20 held in Lima, Peru, in December 2014, participating countries outlined the universal GHG reduction agreement to be finalized in 2015 at COP 21 in Paris. On November 11, 2014, President Obama and President Xi Jinping of China jointly announced their respective "intended nationally determined contributions" for post 2020 greenhouse gas emission reductions. The US announced net greenhouse gas emission reductions of 26-28 percent below 2005 levels by 2025, while China announced targets to peak $CO_2$ emissions around 2030, and to increase the non-fossil fuel share of all energy to around 20 percent by 2030. Together, the U.S. and China account for over one–third of global greenhouse gas emissions.

*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 ($CO_2$) 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 $CO_2$ emissions for new fossil-fuel electric generating units, particularly coal-fired units. Under the President's memorandum, the U.S. EPA was also required to propose a Section 111(d) rule no later than June 1, 2014 to establish $CO_2$ emission regulations for existing stationary sources. The second rulemaking, under Section 111(d) of the Clean Air Act, focuses on modified, reconstructed and existing fossil power plants. The proposed rule was published in the Federal Register on June 18, 2014, and the public comment period closed on December 1, 2014. The Climate Action Plan calls for the rule to be finalized no later than June 1, 2015, and requires that states submit to U.S. EPA their implementation plans no later than June 30, 2016.

*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 the regional RGGI $CO_2$ budget was reduced, starting in 2014, from its previous 165 million ton level to 91 million tons, with a 25 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 $CO_2$ allowances available for purchase at auction. (CCR trigger prices are $4 in 2014, $6 in 2015, $8 in 2016 and $10 in 2017, after 2017 the CCR price increases by 2.5 percent each year). 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 was chartered in 2007 and released a 42 greenhouse gas reduction strategy, climate action plan, on August 27, 2008. The plan's primary policy recommendation to formally 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) which requires Maryland to reduce its GHG emissions by 25 percent below 2006 levels by 2020. It also directed the Maryland Department of Environment to prepare and implement an action plan which was published in October of 2013. Maryland's electricity consumption reduction goals, required under the "Empower Maryland" program, and mandatory State participation in RGGI Program, are listed as the energy sector's contribution in the plan. The plan also advocated raising the renewable portfolio standard requirement from 20% by 2022 to 25% by 2022. The Department of Environment is required to submit a December 2015 report to the Governor and General Assembly on progress towards the 25% mandate; its costs and benefits; the need for target adjustments; and the status of federal programs. In 2016, the Legislature will review the progress report, its economic impacts on manufacturing sector and other information and determine whether to continue, adjust or eliminate the requirement to achieve a 25% reduction by 2020.

*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.

Based on an independent third-party verification of Exelon's GHG performance through year-end 2013, it achieved the Exelon 2020 goal of abating 17.5 million tonnes of GHG emissions annually, seven years ahead of plan. Exelon's approach for addressing the issue of climate change is currently focused on continuing to manage its GHG emissions from internal operations, contributing to reducing overall grid GHG emissions and ensuring the resiliency of its infrastructure in response to the physical impacts of climate change.

***Renewable and Alternative Energy Portfolio Standards***

Thirty-nine states and the District of Columbia have adopted some form of RPS requirement. 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.

Illinois utilities are 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 by Illinois legislation. As of December 31, 2014, ComEd had purchased sufficient renewable energy resources or equivalents, such as RECs, to comply with the Illinois 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 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on ComEd's procurement plans. See Note 22—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for information regarding ComEd's future commitments for the procurement of RECs.

The AEPS Act became effective for PECO on January 1, 2011. During 2014, PECO was required to supply approximately 4.5% 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, 2014 and subsequently 5.0% beginning June 1, 2014 and continuing through May 31, 2015. 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, 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 2014, 10.3% was required from Tier 1 renewable sources, including at least 0.35% derived from solar energy, and 2.5% from Tier 2 renewable sources. 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 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—Regulatory Matters and Note 22—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information.

**Executive Officers of the Registrants as of February 13, 2015**

***Exelon***

| Name | Age | Position | Period |
|---|---|---|---|
| Crane, Christopher M. . . . . . . | 56 | 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. . . . . . . . | 49 | 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. . . . . . . . . . . | 54 | 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 |
| Pramaggiore, Anne R. . . . . . . | 56 | Chief Executive Officer, ComEd | 2012 - Present |
| | | President, ComEd | 2009 - Present |
| | | Chief Operating Officer, ComEd | 2009 - 2012 |
| Adams, Craig L. . . . . . . . . . . . | 62 | President and Chief Executive Officer, PECO | 2012 - Present |
| | | Senior Vice President and Chief Operating Officer, PECO | 2007 - 2012 |
| Butler, Calvin G. . . . . . . . . . . . | 45 | Chief Executive Officer, BGE | 2014 - Present |
| | | Senior Vice President, Regulatory and External Affairs, BGE | 2013 - 2014 |
| | | Senior Vice President, Corporate Affairs, Exelon | 2011 - 2013 |
| | | Senior Vice President, Human Resources, Exelon | 2010 - 2011 |
| | | Senior Vice President, Corporate Affairs, ComEd | 2009 - 2010 |
| Von Hoene Jr., William A. . . . | 61 | Senior Executive Vice President and Chief Strategy Officer, Exelon | 2012 - Present |
| | | Executive Vice President, Finance and Legal, Exelon | 2009 - 2012 |
| Thayer, Jonathan W. . . . . . . . | 43 | Senior Executive Vice President and Chief Financial Officer, Exelon | 2012 - Present [(a)] |
| | | Senior Vice President and Chief Financial Officer, Constellation Energy; Treasurer, Constellation Energy | 2008 - 2012 |
| Aliabadi, Paymon . . . . . . . . . . | 52 | 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 |
| DesParte, Duane M. . . . . . . . . | 51 | Senior Vice President and Corporate Controller, Exelon | 2008 - Present |

***Generation***

| Name | Age | Position | Period |
|---|---|---|---|
| Cornew, Kenneth W. | 49 | 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 |
| Nigro, Joseph | 50 | 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 |
| Pacilio, Michael J. | 54 | Executive Vice President and Chief Operating Officer, Exelon Generation | 2015 - Present |
| | | President, Exelon Nuclear; Senior Vice President and Chief Nuclear Officer, Generation | 2010 - 2015 |
| | | Chief Operating Officer, Exelon Nuclear | 2007 - 2010 |
| Hanson, Bryan C. | 49 | President and Chief Nuclear Officer, Exelon Nuclear; Senior Vice President, Exelon Generation | 2015 - Present |
| | | Chief Operating Officer, Exelon Nuclear | 2014 - 2015 |
| | | Senior Vice President of Operations, Generation | 2010 - 2013 |
| | | Vice President of Operations, Generation | 2009 - 2010 |
| DeGregorio, Ronald | 52 | 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. | 48 | 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 | 48 | 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 |

***ComEd***

| Name | Age | Position | Period |
|---|---|---|---|
| Pramaggiore, Anne R. | 56 | Chief Executive Officer, ComEd | 2012 - Present |
| | | President, ComEd | 2009 - Present |
| | | Chief Operating Officer, ComEd | 2009 - 2012 |
| Donnelly, Terence R. | 54 | Executive Vice President and Chief Operating Officer, ComEd | 2012 - Present |
| | | Executive Vice President, Operations, ComEd | 2009 - 2012 |
| Trpik Jr., Joseph R. | 45 | Senior Vice President, Chief Financial Officer and Treasurer, ComEd | 2009 - Present |
| Jensen, Val | 59 | Senior Vice President, Customer Operations, ComEd | 2012 - Present |
| | | Vice President, Marketing and Environmental Programs, ComEd | 2008 - 2012 |
| O'Neill, Thomas S. | 52 | Senior Vice President, Regulatory and Energy Policy and General Counsel, ComEd | 2010 - Present |
| | | Senior Vice President, Exelon | 2009 - 2010 |
| Marquez Jr., Fidel | 53 | Senior Vice President, Governmental and External Affairs, ComEd | 2012 - Present |
| | | Senior Vice President, Customer Operations, ComEd | 2009 - 2012 |
| Brookins, Kevin B. | 53 | 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 | 50 | Senior Vice President, Distribution Operations, ComEd | 2010 - Present |
| | | Vice President, Transmission and Substations, ComEd | 2007 - 2010 |
| Kozel, Gerald J. | 42 | Vice President, Controller, ComEd | 2013 - Present |
| | | Assistant Corporate Controller, Exelon | 2012 - 2013 |
| | | Director of Financial Reporting and Analysis, Exelon | 2009 - 2012 |

***PECO***

| Name | Age | Position | Period |
|---|---|---|---|
| Adams, Craig L. | 62 | President and Chief Executive Officer, PECO | 2012 - Present |
| | | Senior Vice President and Chief Operating Officer, PECO | 2007 - 2012 |
| Barnett, Phillip S. | 51 | Senior Vice President and Chief Financial Officer, PECO | 2007 - Present |
| | | Treasurer, PECO | 2012 - Present |
| Innocenzo, Michael A. | 49 | 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 |
| Webster Jr., Richard G. | 53 | Vice President, Regulatory Policy and Strategy, PECO | 2012 - Present |
| | | Director of Rates and Regulatory Affairs | 2007 - 2012 |
| Murphy, Elizabeth A. | 55 | Vice President, Governmental and External Affairs, PECO | 2012 - Present |
| | | Director, Governmental & External Affairs, PECO | 2007 - 2012 |
| Jiruska, Frank J. | 54 | Vice President, Customer Operations, PECO | 2013 - Present |
| | | Director of Energy and Marketing Services, PECO | 2010 - 2013 |
| Diaz Jr., Romulo L. | 68 | Vice President and General Counsel, PECO | 2012 - Present |
| | | Vice President, Governmental and External Affairs, PECO | 2009 - 2012 |
| Bailey, Scott A. | 38 | Vice President and Controller, PECO | 2012 - Present |
| | | Assistant Controller, Generation | 2011 - 2012 |
| | | Director of Accounting, Power Team | 2007 - 2011 |

***BGE***

| Name | Age | Position | Period |
|---|---|---|---|
| Butler, Calvin G. | 45 | Chief Executive Officer, BGE | 2014 - Present |
| | | Senior Vice President, Regulatory and External Affairs, BGE | 2013 - 2014 |
| | | Senior Vice President, Corporate Affairs, Exelon | 2011 - 2013 |
| | | Senior Vice President, Human Resources, Exelon | 2010 - 2011 |
| | | Senior Vice President, Corporate Affairs, ComEd | 2009 - 2010 |
| Woerner, Stephen J. | 47 | President, BGE | 2014 - Present |
| | | Chief Operating Officer, BGE | 2012 - Present |
| | | Senior Vice President, BGE | 2009 - 2014 |
| | | 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 |
| Vahos, David M. | 42 | Chief Financial Officer and Treasurer | 2014 - Present |
| | | Vice President and Controller, BGE | 2012 - 2014 |
| | | Executive Director, Audit, Constellation | 2010 - 2012 |
| | | Director, Finance, BGE | 2006 - 2010 |
| Case, Mark D. | 53 | Vice President, Strategy and Regulatory Affairs, BGE | 2012 - Present |
| | | Senior Vice President, Strategy and Regulatory Affairs, BGE | 2007 - 2012 |
| Biagiotti, Robert D. | 45 | Vice President, Customer Operations and Chief Customer Officer, BGE | 2015 - Present |
| | | Vice President, Gas Distribution, BGE | 2011-2015 |
| | | Director, Gas and Electric Field Services, BGE | 2008-2011 |
| Gahagan, Daniel P. | 61 | Vice President and General Counsel, BGE | 2007 - Present |
| Bauer, Matthew N. | 38 | Vice President and Controller, BGE | 2014 - Present |
| | | Vice President of Power Finance, Exelon Power | 2012 - 2014 |
| | | Director, FP&A and Retail, Constellation | 2012 - 2012 |
| | | Executive Director, Corporate Development, Constellation | 2009 - 2012 |

(a) Effective July 1, 2014, Jonathan W. Thayer's title was changed from Executive Vice President and Chief Financial Officer, Exelon to Senior Executive Vice President and Chief Financial Officer, Exelon.

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

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

Exelon's common stock is listed on the New York Stock Exchange. As of January 31, 2015, there were 859,833,343 shares of common stock outstanding and approximately 123,997 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:

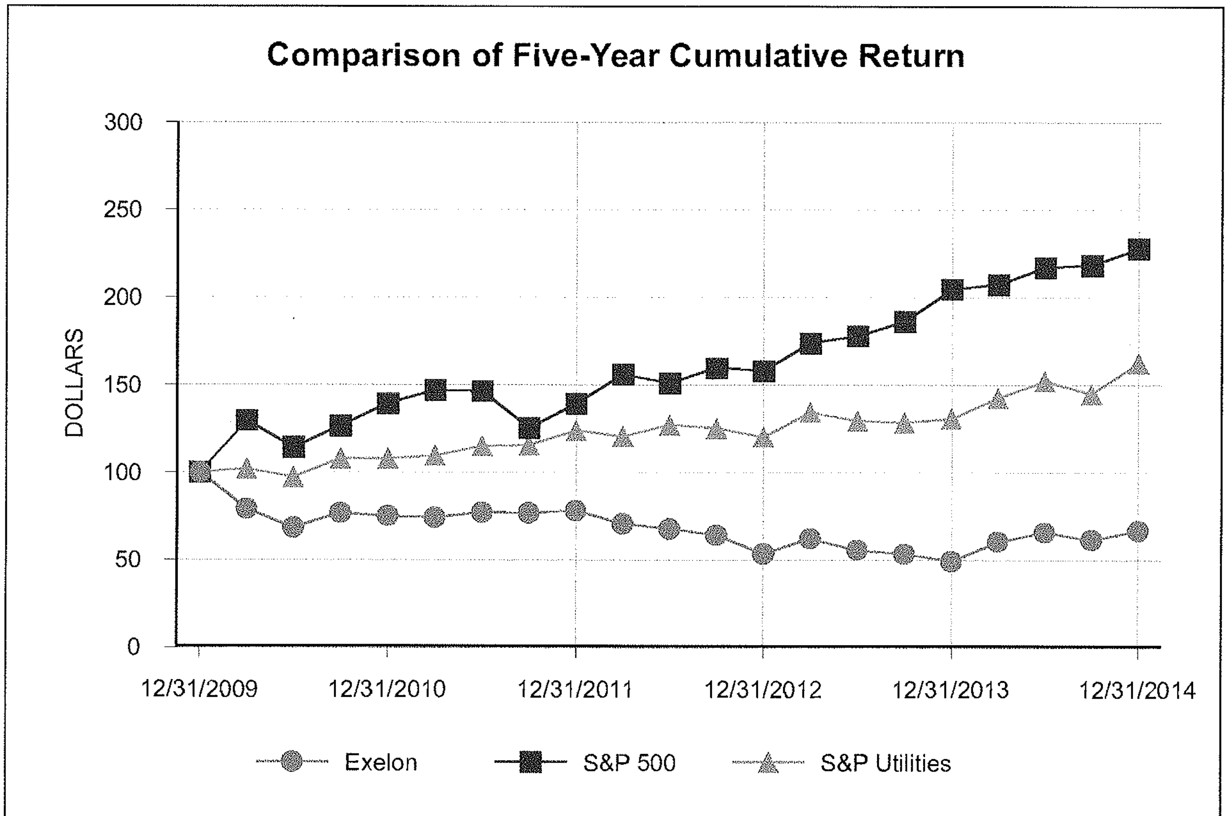
| | 2014 | | | | 2013 | | | |
|---|---|---|---|---|---|---|---|---|
| | Fourth Quarter | Third Quarter | Second Quarter | First Quarter | Fourth Quarter | Third Quarter | Second Quarter | First Quarter |
| High price | $38.93 | $36.26 | $37.73 | $33.94 | $30.59 | $32.42 | $37.80 | $34.56 |
| Low price | 33.07 | 30.66 | 33.11 | 26.45 | 26.64 | 29.42 | 29.84 | 29.10 |
| Close | 37.08 | 34.09 | 36.48 | 33.56 | 27.39 | 29.64 | 30.88 | 34.48 |
| Dividends | 0.310 | 0.310 | 0.310 | 0.310 | 0.310 | 0.310 | 0.310 | 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 2010 through 2014.

This performance chart assumes:

- $100 invested on December 31, 2009 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, | | | | | |
|---|---|---|---|---|---|---|
| | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 |
| Exelon Corporation | $100 | $74.88 | $77.99 | $53.48 | $49.25 | $66.68 |
| S&P 500 | $100 | $139.23 | $139.23 | $157.89 | $204.63 | $227.94 |
| S&P Utilities | $100 | $107.71 | $123.69 | $120.09 | $130.60 | $162.33 |

**Generation**

As of January 31, 2015, Exelon indirectly held the entire membership interest in Generation.

**ComEd**

As of January 31, 2015, there were 127,016,950 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, 2015, in addition to Exelon, there were 297 record holders of ComEd common stock. There is no established market for shares of the common stock of ComEd.

**PECO**

As of January 31, 2015, 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, 2015, there were 1,000 outstanding shares of common stock, without par value, of BGE, all of which were indirectly held by Exelon.

**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, in connection with the Constellation merger, BGE was 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 and notify the MDPSC that BGE's equity ratio is at least 48% within five business days after dividend payment. 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, 2014, Exelon had retained earnings of $10,910 million, including Generation's undistributed earnings of $3,803 million, ComEd's retained earnings of $851 million consisting of retained earnings appropriated for future dividends of $2,490 million, partially offset by $(1,639) million of unappropriated retained deficits, PECO's retained earnings of $681 million, and BGE's retained earnings of $1,203 million.

The following table sets forth Exelon's quarterly cash dividends per share paid during 2014 and 2013:

| | 2014 | | | | 2013 | | | |
|---|---|---|---|---|---|---|---|---|
| (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 | $0.310 | $0.310 | $0.310 | $0.310 | $0.525 |

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

| | 2014 | | | | 2013 | | | |
|---|---|---|---|---|---|---|---|---|
| (in millions) | 4th Quarter | 3rd Quarter | 2nd Quarter | 1st Quarter | 4th Quarter | 3rd Quarter | 2nd Quarter | 1st Quarter |
| Generation | $205 | $205 | $205 | $30 | $75 | $76 | $263 | $211 |
| ComEd | 77 | 77 | 77 | 76 | 55 | 55 | 55 | 55 |
| PECO | 80 | 80 | 80 | 80 | 83 | 83 | 83 | 83 |

***First Quarter 2015 Dividend.*** On January 27, 2015, the Exelon Board of Directors declared a first quarter 2015 regular quarterly dividend of $0.31 per share on Exelon's common stock payable on March 10, 2015, to shareholders of record of Exelon at the end of the day on February 13, 2015.

## SELECTED FINANCIAL DATA

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

| | For the Years Ended December 31, | | | | |
|---|---|---|---|---|---|
| (In millions, except per share data) | 2014 [(a)] | 2013 | 2012 [(b)] | 2011 | 2010 |
| **Statement of Operations data:** | | | | | |
| Operating revenues | $27,429 | $24,888 | $23,489 | $19,063 | $18,644 |
| Operating income | 3,096 | 3,669 | 2,373 | 4,479 | 4,726 |
| Income from continuing operations | 1,820 | 1,729 | 1,171 | 2,499 | 2,563 |
| Net income | 1,820 | 1,729 | 1,171 | 2,499 | 2,563 |
| Net income attributable to common shareholders | 1,623 | 1,719 | 1,160 | 2,495 | 2,563 |
| Earnings per average common share (diluted): | | | | | |
| Income from continuing operations | $ 1.88 | $ 2.00 | $ 1.42 | $ 3.75 | $ 3.87 |
| Net income | $ 1.88 | $ 2.00 | $ 1.42 | $ 3.75 | $ 3.87 |
| Dividends per common share | $ 1.24 | $ 1.46 | $ 2.10 | $ 2.10 | $ 2.10 |
| Average shares of common stock outstanding—diluted | 864 | 860 | 819 | 665 | 663 |

(a) On April 1, 2014, Generation assumed operational control of CENG's nuclear fleet. As a result, the 2014 financial results include CENG's results of operations on a fully consolidated basis.
(b) 2012 financial results include the activity of Constellation from the merger effective date of March 12, 2012 through December 31, 2012.

| (In millions) | December 31, 2014 | 2013 | 2012 | 2011 | 2010 |
|---|---|---|---|---|---|
| **Balance Sheet data:** | | | | | |
| Current assets | $12,097 | $10,137 | $10,140 | $ 5,713 | $ 6,398 |
| Property, plant and equipment, net | 52,087 | 47,330 | 45,186 | 32,570 | 29,941 |
| Noncurrent regulatory assets | 6,076 | 5,910 | 6,497 | 4,518 | 4,140 |
| Goodwill | 2,672 | 2,625 | 2,625 | 2,625 | 2,625 |
| Other deferred debits and other assets | 13,882 | 13,922 | 14,113 | 9,569 | 9,136 |
| Total assets | $86,814 | $79,924 | $78,561 | $54,995 | $52,240 |
| Current liabilities | $ 8,762 | $ 7,728 | $ 7,791 | $ 5,134 | $ 4,240 |
| Long-term debt, including long-term debt to financing trusts | 20,010 | 18,271 | 18,346 | 12,189 | 12,004 |
| Noncurrent regulatory liabilities | 4,550 | 4,388 | 3,981 | 3,627 | 3,555 |
| Other deferred credits and other liabilities | 29,359 | 26,597 | 26,626 | 19,570 | 18,791 |
| Preferred securities of subsidiary | — | — | 87 | 87 | 87 |
| Noncontrolling interest | 1,332 | 15 | 106 | 3 | 3 |
| BGE preference stock not subject to mandatory redemption | 193 | 193 | 193 | — | — |
| Shareholders' equity | 22,608 | 22,732 | 21,431 | 14,385 | 13,560 |
| Total liabilities and shareholders' equity | $86,814 | $79,924 | $78,561 | $54,995 | $52,240 |

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

### Executive Overview

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

- *Generation,* whose integrated business consists of the generation, physical delivery and marketing of power across multiple geographical regions through its customer-facing business, Constellation, which sells electricity and natural gas to both wholesale and retail customers. Generation also sells renewable energy and other energy-related products and services, and engages in natural gas and oil exploration and production activities (Upstream).
  - As a result of the Constellation merger, Generation owns a 50.01% interest in CENG. During 2014, Generation assumed the operating licenses and corresponding operational control of CENG's nuclear fleet. As a result, Exelon and Generation fully consolidated CENG's financial position and results of operations into their businesses beginning on April 1, 2014.
- *ComEd,* whose business consists of the purchase and regulated retail sale of electricity and the provision of electricity transmission and distribution services to retail customers 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 electricity 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 natural gas and the provision of electricity distribution and transmission and gas 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—Segment Information 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 the year ended December 31, 2014 compared to the same period in 2013. The 2014 financial results only include the operations of CENG on a fully consolidated basis from the date Generation assumed operational control, April 1, 2014, through December 31, 2014. All amounts presented below are before the impact of income taxes, except as noted.

| | The Years Ended December 31, | | | | | | | Favorable (Unfavorable) Variance |
|---|---|---|---|---|---|---|---|---|
| | 2014 | | | | | | 2013 | |
| | Generation (a) | ComEd | PECO | BGE | Other | Exelon | Exelon | |
| **Operating revenues** | $17,393 | $4,564 | $3,094 | $3,165 | $(787) | $27,429 | $24,888 | $ 2,541 |
| **Purchased power and fuel expense** | 9,925 | 1,177 | 1,261 | 1,417 | (777) | 13,003 | 10,724 | (2,279) |
| **Revenue net of purchased power and fuel expense** (b) | 7,468 | 3,387 | 1,833 | 1,748 | (10) | 14,426 | 14,164 | 262 |
| **Other operating expenses** | | | | | | | | |
| Operating and maintenance | 5,566 | 1,429 | 866 | 717 | (10) | 8,568 | 7,270 | (1,298) |
| Depreciation and amortization | 967 | 687 | 236 | 371 | 53 | 2,314 | 2,153 | (161) |
| Taxes other than income | 465 | 293 | 159 | 221 | 16 | 1,154 | 1,095 | (59) |
| Total other operating expenses | 6,998 | 2,409 | 1,261 | 1,309 | 59 | 12,036 | 10,518 | (1,518) |
| **Equity in (losses) earnings of unconsolidated affiliates** | (20) | — | — | — | — | (20) | 10 | (30) |
| **Gain (loss) on sales of assets** | 437 | 2 | — | — | (2) | 437 | 13 | 424 |
| **Gain on consolidation and acquisition of businesses** | 289 | — | — | — | — | 289 | — | 289 |
| **Operating income (loss)** | 1,176 | 980 | 572 | 439 | (71) | 3,096 | 3,669 | (573) |
| **Other income and (deductions)** | | | | | | | | |
| Interest expense, net | (356) | (321) | (113) | (106) | (169) | (1,065) | (1,356) | 291 |
| Other, net | 406 | 17 | 7 | 18 | 7 | 455 | 460 | (5) |
| Total other income and (deductions) | 50 | (304) | (106) | (88) | (162) | (610) | (896) | 286 |
| **Income (loss) before income taxes** | 1,226 | 676 | 466 | 351 | (233) | 2,486 | 2,773 | (287) |
| **Income taxes** | 207 | 268 | 114 | 140 | (63) | 666 | 1,044 | 378 |
| **Net income (loss)** | 1,019 | 408 | 352 | 211 | (170) | 1,820 | 1,729 | 91 |
| Net income attributable to noncontrolling interests, preferred security dividends and preference stock dividends | 184 | — | — | 13 | — | 197 | 10 | (187) |
| **Net income (loss) attributable to common shareholders** | $ 835 | $ 408 | $ 352 | $ 198 | $(170) | $ 1,623 | $ 1,719 | $ (96) |

(a) On April 1, 2014, Generation assumed operational control of CENG's nuclear fleet. As a result, the 2014 financial results include CENG's results of operations on a fully consolidated basis from April 1, 2014 through December 31, 2014.

(b) 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 attributable to common shareholders was $1,623 million for the year ended December 31, 2014 as compared to $1,719 million for the year ended December 31, 2013, and diluted earnings per average common share were $1.88 for the year ended December 31, 2014 as compared to $2.00 for the year ended December 31, 2013.

Operating revenue net of purchased power and fuel expense, which is a non-GAAP measure discussed below, increased by $262 million as compared to 2013. The year-over-year increase reflects the inclusion of CENG's results beginning April 1, 2014 and was primarily due to the following favorable factors:

- Increase of $815 million at Generation primarily due to the inclusion of CENG's results beginning April 1, 2014 through December 31, 2014, a decrease in fuel costs related to the cancellation of DOE spent nuclear fuel disposal fees, increased capacity prices related to the Reliability Pricing Model (RPM) for the PJM Interconnection, LLC (PJM) market, and favorable portfolio management activities in the New England and South regions; partially offset by higher procurement costs for replacement power related to the extreme cold weather in the first quarter of 2014 and lower realized energy prices related to executing Generation's ratable hedging strategy;

- Increase of $365 million at Generation related to the reduction in amortization of in-the-money energy contracts recorded at fair value at the Constellation merger date and an increase related to the amortization of out-of-the money energy contracts recorded at fair value upon the consolidation of CENG;
- Increase of $30 million at ComEd primarily reflecting higher transmission revenue due to increased capital investment and an increase of $93 million as a result of increased cost recovery associated with energy efficiency programs and uncollectible accounts expense (both offset below in operating and maintenance expense);
- Increase of $33 million at PECO primarily due to increased recovery from regulatory programs (offset below primarily in operating and maintenance expense); and
- Increase of $104 million at BGE primarily due to increased distribution revenue as a result of the 2013 and 2014 electric and natural gas distribution rate case orders issued by the Maryland PSC, increased cost recovery for energy efficiency and demand response programs (offset below in depreciation and amortization expense), and increased transmission revenue pursuant to increased rates effective June 2014.

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

- Decrease of $1,095 million at Generation due to mark-to-market losses of $591 million in 2014 from economic hedging activities compared to $504 million in mark-to-market gains in 2013.
- Decrease of $16 million at ComEd due to unfavorable weather in the ComEd service territory.

Operating and maintenance expense increased by $1,298 million as compared to 2013 primarily due to the following unfavorable factors:

- Increase in Generation's labor, contracting and materials costs of $361 million primarily due to the inclusion of CENG's results from April 1, 2014 through December 31, 2014, an increase of $44 million resulting from expenses recorded for a Constellation merger commitment, an increase of $54 million as a result of an increase in the number of planned nuclear refueling outage days at Generation, primarily related to the inclusion of CENG's plants beginning April 1, 2014, and an increase of $16 million in the reserve for future asbestos-related bodily injury claims;
- Increase in labor, contracting and materials costs of $56 million at ComEd associated with EIMA smart meter projects and $22 million at BGE due to increased maintenance activities;
- Increase in Generation's accretion expense of $78 million primarily due to the inclusion of CENG's results from April 1, 2014 through December 31, 2014;
- Long-lived asset impairments at Generation of $663 million in 2014 compared to $157 million in 2013.
- Increased storm costs at PECO and BGE of $100 million and $21 million, respectively;
- Increased spending on energy and efficiency programs and increased uncollectible accounts expense at ComEd of $93 million; and
- Increased uncollectible accounts expense at BGE of $17 million.

The year-over-year increase in operating and maintenance expense was partially offset by the following favorable factor:

- A reduction in pension and non-pension postretirement benefits expense of $178 million primarily at Exelon, Generation, and ComEd, resulting from plan design changes for certain OPEB plans and the favorable impact of higher actuarially assumed pension and OPEB discount rates for 2014, partially offset by the inclusion of CENG's pension and non-pension postretirement benefits expense from April 1, 2014 through December 31, 2014.

Depreciation and amortization expense increased by $161 million primarily as a result of the inclusion of CENG's results from April 1, 2014 through December 31, 2014, increased depreciation expense across the operating companies for ongoing capital expenditures, and higher regulatory asset amortization related to energy efficiency and demand response expenditures.

Exelon recorded $437 million at Generation as a result of gains recorded on the sales of ownership interest in certain generating stations in 2014.

Exelon recorded a $261 million gain upon consolidation of CENG resulting from the difference in fair value of CENG's net assets as of April 1, 2014, and the equity method investment previously recorded on Generation's and Exelon's books and the settlement of pre-existing transactions between Generation and CENG. Additionally, Exelon recorded a $28 million bargain-purchase gain related to the Integrys acquisition.

Interest expense decreased by $291 million primarily as a result of a decrease in 2014 given ComEd's 2013 remeasurement of Exelon's like-kind exchange tax positions, offset at Exelon by an increase in 2014 related to financing activities associated with the pending PHI merger.

Other, net increased by $5 million primarily at Generation as a result of favorable settlements in 2014 of certain income tax positions on Constellation's pre-acquisition 2009-2012 tax returns and the change in realized and unrealized gains and losses on NDT funds.

Exelon's effective income tax rates for the years ended December 31, 2014 and 2013 were 26.8% and 37.6%, 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.

For further detail regarding the financial results for the years ended December 31, 2014 and 2013, 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, 2014 were $2,068 million, or $2.39 per diluted share, compared with adjusted (non-GAAP) operating earnings of $2,149 million, or $2.50 per diluted share, for the same period in 2013. 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 attributable to common shareholders as determined in accordance with GAAP and adjusted (non-GAAP) operating earnings for the year ended December 31, 2014 as compared to 2013:

| (All amounts after tax; in millions, except per share amounts) | For the years ended December 31, 2014 | 2014 Earnings per Diluted Share | 2013 | 2013 Earnings per Diluted Share |
|---|---|---|---|---|
| **Net Income Attributable to Common Shareholders** | $1,623 | $ 1.88 | $1,719 | $ 2.00 |
| Mark-to-Market Impact of Economic Hedging Activities (a) | 363 | 0.42 | (310) | (0.35) |
| Unrealized Gains Related to NDT Fund Investments (b) | (86) | (0.10) | (78) | (0.09) |
| Plant Retirements and Divestitures (c) | (245) | (0.28) | (13) | (0.02) |
| Asset Retirement Obligation (d) | (13) | (0.02) | 7 | 0.01 |
| Merger and Integration Costs (e) | 185 | 0.21 | 87 | 0.08 |
| Amortization of Commodity Contract Intangibles (f) | 64 | 0.07 | 347 | 0.41 |
| Reassessment of State Deferred Income Taxes (g) | (27) | (0.03) | 4 | — |
| Long-Lived Asset Impairments (h) | 435 | 0.50 | 110 | 0.14 |
| Bargain-Purchase Gain on Integrys acquisition (i) | (28) | (0.03) | — | — |
| Gain on CENG Integration (j) | (159) | (0.18) | — | — |
| Tax Settlements (k) | (106) | (0.12) | — | — |
| CENG Non-Controlling Interest (l) | 62 | 0.07 | — | — |
| Remeasurement of Like-Kind Exchange Tax Position (m) | — | — | 267 | 0.31 |
| Midwest Generation Bankruptcy Charges (n) | — | — | 16 | 0.02 |
| Amortization of the Fair Value of Certain Debt (o) | — | — | (7) | (0.01) |
| **Adjusted (non-GAAP) Operating Earnings** | $2,068 | $ 2.39 | $2,149 | $ 2.50 |

(a) Reflects the impact of losses (gains) for the years ended December 31, 2014 and December 31, 2013 (net of taxes of $232 million and ($201) million, respectively) on Generation's economic hedging activities. 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, 2014 and December 31, 2013 (net of taxes of $(77) million and $(144) million, respectively) on Generation's NDT fund investments for Non-Regulatory Agreement Units. See Note 15—Asset Retirement Obligations 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 sales of Generation's ownership interests in generating stations for the years ended December 31, 2014 and December 31, 2013 (net of taxes of $(163) million and ($4) million, respectively).

(d) Reflects the impacts of a decrease in Generation's decommissioning obligation for the year ended December 31, 2014 (net of taxes of $(4) million). Reflects the impacts 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).

(e) Reflects certain costs incurred for the years ended December 31, 2014 and December 31, 2013 (net of taxes of $84 million and $33 million, respectively) including professional fees, employee-related expenses, integration activities, upfront credit facilities, merger commitments, and certain pre-acquisition contingencies, if and when applicable to the Constellation merger in 2013 and the Constellation merger, CENG integration, acquisition of Integrys Energy Services, Inc. (Integrys) and pending PHI acquisition in 2014.

(f) Reflects the non-cash impact for the years ended December 31, 2014 and December 31, 2013 (net of taxes of $68 million and $219 million, respectively) of the amortization of intangibles assets, net, related to commodity contracts recorded at fair value at the 2012 Constellation merger date, the 2014 CENG integration date, and the 2014 Integrys acquisition date.

(g) Reflects the non-cash impacts of the remeasurement of state deferred income taxes, primarily as a result of changes in forecasted apportionment.

(h) In 2014, reflects charges to earnings related to the impairments of certain generating assets held for sale, Upstream assets, and wind generating assets (net of taxes of $250 million). In 2013, reflects a charge to earnings primarily related to the cancellation of previously capitalized nuclear uprate projects and the impairment of certain wind generating assets (net of taxes of $69 million).

(i) Reflects the excess of the fair value of assets and liabilities acquired over the purchase price for the Integrys acquisition (net of taxes of $(16) million) on November 1, 2014.

(j) Reflects the non-cash gain recorded upon consolidation of CENG in accordance with the execution of the NOSA on April 1, 2014 (net of taxes of $(102) million).

(k) Reflects a benefit related to the favorable settlement in 2014 of certain income tax positions on Constellation's pre-acquisition 2009-2012 tax returns.

(l) Pursuant to the April 1, 2014 consolidation, represents adjustments to account for the CENG interest not owned by Generation, where applicable.

(m) For 2013, reflects a non-cash charge to earnings (net of taxes of $102 million) resulting from the remeasurement of a like-kind exchange tax position taken on ComEd's 1999 sale of fossil generating assets. See Note 14—Income Taxes of the Combined Notes to the Consolidated Financial Statements for additional information.

(n) Reflects costs incurred in 2013 to establish estimated liabilities (net of taxes of $10 million) 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.

(o) Reflects the 2013 non-cash amortization of certain debt (net of taxes of ($5) million) recorded at fair value at the Constellation merger date which was retired in the second quarter of 2013. See Note 4—Mergers, Acquisitions, and Dispositions of the Combined Notes to the Consolidated Financial Statements for additional information.

***Merger and Acquisition Costs***

As discussed above, Exelon has incurred and will continue to incur costs associated with the Integrys and PHI acquisitions including employee-related expenses (e.g. severance, retirement, relocation and retention bonuses), financing costs, integration initiatives, and certain pre-acquisition contingencies.

For the year ended December 31, 2014, expense has been recognized for costs incurred to achieve the Constellation merger, CENG integration, Integrys acquisition and proposed PHI acquisition as follows:

| | Pre-tax Expense Twelve Months Ended December 31, 2014 | | | | |
|---|---|---|---|---|---|
| **Merger Integration and Acquisition Costs:** | **Generation** | **ComEd** | **PECO** | **BGE** | **Exelon** |
| Financing [(a)] | $— | $— | $— | $— | $131 |
| Regulatory Commitments [(b)] | 44 | — | — | — | 44 |
| Transaction [(c)] | — | — | — | — | 26 |
| Employee-Related [(d)] | 5 | — | — | — | 5 |
| Other [(e)] | 56 | 4 | 2 | 2 | 65 |
| Total | $105 | $ 4 | $ 2 | $ 2 | $271 |

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

(a) Reflects costs incurred at Exelon related to the financing of the PHI merger, including upfront credit facility fees.
(b) Reflects costs incurred at Generation for a Constellation merger commitment.
(c) 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 transactions.
(d) Costs primarily for employee severance, pension and OPEB expense and retention bonuses. ComEd established regulatory assets of $2 million for the year ended December 31, 2013. The majority of these costs are expected to be recovered over a five-year period. These costs are not included in the table above.
(e) Costs to integrate CENG and Constellation processes and systems into Exelon and to terminate certain Constellation debt agreements. For the year ended December 31, 2014, also includes professional fees primarily related to integration for the proposed PHI acquisition. ComEd and BGE established regulatory assets of $9 million and $12 million, respectively, for the year ended December 31, 2013, for certain other merger and integration costs, which are not included in the table above.

As of December 31, 2014, Exelon projects incurring total additional PHI acquisition and integration related expenses of $650 million, of which approximately $100 million is expected to be capitalized to property, plant and equipment excluding the direct investment Exelon and PHI have proposed to the PHI utilities respective customers.

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 estimate 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 was contingent upon the developer obtaining all required approvals, permits and financing for the construction of a building in Baltimore, Maryland. The operating lease became effective during the second quarter of 2014 when these outstanding contingencies were met by the developer. The building is expected to be ready for occupancy in approximately 2 years. See Note 22—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for further information related to the lease commitments.

**Exelon's Strategy and Outlook for 2015 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. Exelon's strategy is to leverage its integrated business model to create value and diversify its business. Exelon's competitive and regulated businesses feature a mix of attributes that, when combined, offer shareholders and customers a unique value proposition:

- Generation's competitive businesses provide commodity exposure and a platform to diversify into adjacent markets, while providing residual dividend support.
- Exelon's utilities provide a foundation for stable earnings and dividend support, which translates to a stable currency in our stock.

Exelon believes its strategy provides a platform for optimal success in an energy industry experiencing fundamental and sweeping change. While enhancing Exelon's core value, it enables it to take advantage of a myriad of opportunities, rather than focusing on any one segment of the energy industry value chain.

Generation's competitive businesses create value for customers by providing innovative solutions and reliable, clean and affordable energy. 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 Generation 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. The Exelon utilities only invest in rate base where it provides a net benefit to customers and the community by increasing reliability and the service experience or otherwise meeting customer needs. The Exelon utilities make these investments prudently and at the lowest reasonable cost to customers. 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 $16 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.

Various market, financial, and other factors could affect the Registrants' success in pursuing their strategies. Exelon continues to assess infrastructure, operational, commercial, policy, and legal solutions to these issues.

***Proposed Merger with Pepco Holdings, Inc.***

On April 29, 2014, Exelon and Pepco Holdings, Inc. (PHI) signed an agreement and plan of merger (as subsequently amended and restated as of July 18, 2014, the Merger Agreement) to combine the two companies in an all cash transaction. The resulting company will retain the Exelon name and be headquartered in Chicago. Under the Merger Agreement, PHI's shareholders will receive $27.25 of cash in exchange for each share of PHI common stock. Exelon intends to fund the all-cash transaction using a combination of approximately $3.5 billion of debt, up to $1 billion cash from asset sales primarily at Generation, and the remainder through issuance of equity (including mandatory convertible securities). In addition, Exelon entered into a 364-day $7.2 billion senior unsecured bridge credit facility to support the contemplated transaction and provide flexibility for timing of permanent financing, which has subsequently been reduced to $3.2 billion as a result of execution of the debt and equity security issuances and the net after-tax cash proceeds from generating asset divestitures during the second half of 2014. See Note 4—Mergers, Acquisitions, and Divestitures, Note 13—Debt and Credit Agreements, and Note 19—Common Stock of the Combined Notes to Consolidated Financial Statements for further information related to these transactions. In connection with the Merger Agreement, Exelon entered into a subscription agreement under which it has purchased $126 million of a new class of nonvoting, nonconvertible and nontransferable preferred securities in PHI as of December 31, 2014, with additional investments of $18 million to be made quarterly up to a maximum aggregate investment of $180 million. As part of the applications for approval of the merger, Exelon and PHI proposed a package of benefits to the PHI utilities' respective customers, providing for direct investment of more than $100 million with the actual amount and timing of any related payments dependent upon settlement discussions in merger regulatory approval proceedings and the terms of regulatory orders approving the merger.

To date, the PHI stockholders, the Virginia State Corporation Commission, the New Jersey Board of Public Utilities (NJBPU) and the FERC have approved the merger of PHI and Exelon. The Federal Communications Commission has also approved the transfer of certain PHI communications licenses. On February 11, 2015, the NJBPU approved the proposed merger and the previously filed settlement signed and filed by Exelon, PHI, Atlantic City Electric (ACE), NJBPU staff, and the Independent Energy Coalition. The settlement provides a package of benefits to ACE customers and the state of New Jersey. This package of benefits includes the establishment of customer rate credit programs, with an aggregate value of $62 million for ACE customers and energy efficiency programs that will provide savings for ACE customers of $15 million.

Completion of the transaction also remains conditioned upon approval by the Public Services Commissions of the District of Columbia, Delaware and Maryland. Procedural schedules have been set in these commission proceedings and final approval decisions are expected in the first half of 2015.

On October 9, 2014, PHI and Exelon each received a request for additional information from the DOJ. The request had the effect of extending the DOJ review period until 30 days after PHI and Exelon each has certified that it has substantially complied with the request. On November 21, 2014, Exelon and PHI each certified that it had substantially complied with the request. Accordingly, the HSR Act waiting period expired on December 22, 2014, and the HSR Act no longer precludes completion of the merger. Although the DOJ allowed the waiting period under the HSR Act to expire without taking any action with respect to the merger, the DOJ has not advised Exelon or PHI that it has concluded its investigation. Exelon and PHI will continue to work cooperatively with the DOJ regarding the proposed merger.

Exelon and PHI continue to expect to complete the merger in the second or third quarter of 2015.

Through December 31, 2014, Exelon has incurred approximately $179 million of expense associated with the proposed merger, including $48 million related to acquisition and integration costs and $131 million of costs incurred to finance the transaction. The Merger Agreement also provides for termination rights for both parties. Under certain circumstances, if the Merger Agreement is terminated, PHI may be required to pay Exelon a termination fee ranging from $259 million to $293 million plus certain expenses. If the transaction does not close due to a regulatory failure, Exelon may be required to pay PHI a termination fee equal to the amount of purchased nonvoting preferred securities of PHI described above, as a result of PHI redeeming the outstanding nonvoting preferred securities for no consideration other than the nominal par value of the stock.

Exelon has listed various potential risks relating to the pending merger with PHI including difficulties that may be encountered in satisfying the conditions to completion of the merger and the potential for developments that might have an adverse effect on Exelon and the ability to realize the expected benefits of the merger. Exelon is taking steps to manage these risks and expects that the merger can be completed on a basis favorable to the company's shareholders and customers. Accordingly, Exelon anticipates closing the transaction in the second or third quarter of 2015. Refer to Note 4—Mergers, Acquisitions, and Dispositions of the Combined Notes to Consolidated Financial Statements for additional information on the merger transaction.

***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. Forward natural gas prices have declined significantly over the last several years; in part reflecting an increase in supply due to strong natural gas production (due to shale gas development).

***Capacity Market Changes in PJM***. In the wake of the January 2014 Polar Vortex that blanketed much of the Eastern and Midwestern United States, it became clear that while a major outage event was narrowly avoided, resources in PJM were not providing the level of reliability expected by customers. To address this disconnect, on December 12, 2014, PJM filed at FERC a proposal to make significant changes to its current capacity market construct, the Reliability Pricing Model (RPM). PJM's proposed changes generally seek to improve resource performance and reliability largely by limiting the excuses for non-performance and by increasing the penalties for performance failures. To cover capital and other costs and risks that suppliers would incur to meet these higher reliability standards, suppliers would be allowed to include adders for such costs as well as risk premiums in their capacity market offers. While offers are expected to put upward pressure on capacity clearing prices, operational improvements made as a result of PJM's proposal are expected to improve reliability, to reduce energy production costs as a result of more efficient operations and to reduce the need for out of market energy payments to suppliers. Exelon participated actively in PJM's stakeholder process through which PJM developed the proposal and is also actively participating in the FERC proceeding including filing comments. PJM asked for a FERC order approving the proposal by April 1, 2015 so PJM can implement the proposal prior to its next capacity auction in May 2015. However, it is not clear when or how the FERC will respond to PJM's proposal or, if it responds within PJM's timeframe, whether FERC will require changes.

***Subsidized Generation***. The rate of expansion of subsidized generation, including 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 attempted to implement or propose 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 in to law in January 2011, the Long Term Capacity Pilot Program Act (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 the price eligible 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 mandated 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 have challenged the constitutionality and other aspects of the New Jersey legislation and the actions taken by the MDPCS in state and federal courts. Ultimately, the Exelon parties prevailed in obtaining orders from the U.S. Court of Appeals for the Third Circuit and the U.S. Court of Appeals for the Fourth Circuit effectively undoing the actions taken by the New Jersey legislature and the MDPSC respectively. The matter has been appealed to the U.S. Supreme Court, and while the Court of Appeals decisions are helpful, there remains risk the Supreme Court will overrule the lower Courts.

As required under their contracts, generator developers who were selected in the New Jersey and Maryland programs (including CPV) offered and cleared in PJM's capacity market auctions held in May 2012, 2013, and 2014. In addition, CPV has announced its intention to move forward with construction of its New Jersey and Maryland plants, 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 court decisions in New Jersey and Maryland are positive developments, continuation of these state efforts, if successful and unabated by an effective minimum offer price rule (MOPR) for future capacity auctions, 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. Exelon continues to monitor developments and participate in stakeholder and other processes to ensure that similar state subsidies are not developed. In addition, Exelon remains active in advocating for competitive markets, while opposing policies that require taxpayers and/ 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.

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

***Energy Demand***. Modest economic growth partially offset by energy efficiency initiatives is resulting in positive growth for electricity for ComEd and PECO, and no projected growth for electricity for BGE. ComEd, PECO and BGE are projecting load volumes to increase by 0.4%, 0.8% and (0.2)%, respectively, in 2015 compared 2014.

***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. The market experienced high price volatility in the first quarter of 2014 which contributed to bankruptcies and consolidations within the industry during the year. However, forward natural gas and power prices are expected to remain low and thus we expect retail competitors to stay aggressive in their pursuit of market share, and that wholesale generators (including Generation) will continue to use their retail operations to hedge generation output.

***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 second quarter 2014 dividend of $0.31 per share on Exelon's common stock. The second quarter dividend was paid on June 10, 2014 to shareholders of record on May 16, 2014. All future quarterly dividends require approval by Exelon's board of directors.

Exelon's board of directors declared the third quarter 2014 dividend of $0.31 per share on Exelon's common stock. The third quarter dividend was paid on September 10, 2014 to shareholders of record on August 15, 2014.

Exelon's board of directors declared the fourth quarter 2014 dividend of $0.31 per share on Exelon's common stock. The fourth quarter dividend was paid on December 10, 2014 to shareholders of record on November 14, 2014.

Exelon's board of directors declared the first quarter 2015 dividend of $0.31 per share on Exelon's common stock. The first quarter dividend will be paid on March 10, 2015, to shareholders of record on February 13, 2015.

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. This strategy has not changed as a result of recent and pending asset divestitures. 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, 2014, the percentage of expected generation hedged for the major reportable segments was 93%-96%, 61%-64% and 31%-34% for 2015, 2016, and 2017 respectively. The percentage of expected generation hedged is the amount of equivalent sales divided by the expected generation (which reflects the divestiture impact of Quail Run). Expected generation is the volume of energy that best represents our commodity position in energy markets from owned or contracted for capacity based upon a simulated dispatch model that makes assumptions regarding future market conditions, which are calibrated to market quotes for power, fuel, load following products, and options. Equivalent sales represent all hedging products, such as wholesale and retail sales of power, options and swaps. Generation has been and will continue to be proactive in using hedging strategies to mitigate commodity price risk in subsequent years as well. See Note 4—Mergers, Acquisition and Dispositions for more detail regarding the divestitures.

Generation procures 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 50% of Generation's uranium concentrate requirements from 2015 through 2019 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 commodity price risk through regulatory mechanisms that allow them to recover procurement costs from retail customers.

### *Growth Opportunities*

With an emphasis on innovation and entrepreneurship, Exelon is currently pursuing growth in both the utility and competitive energy businesses. Identifying and capitalizing on emerging trends and technologies, Exelon plans to invest in new innovative technologies to compete with a new breed of energy players, leverage new technologies to create new or expand existing businesses, and improve productivity and efficiencies within our existing businesses. Management continually evaluates growth opportunities aligned with Exelon's businesses, assets and markets, leveraging Exelon's expertise in those areas.

#### Competitive Energy Businesses

Generation continues to pursue growth in its existing businesses and markets and further diversification across the competitive energy value chain.

- *Leveraging its competencies,*
  - Generation's 2014 acquisition of Integrys allows Generation to expand its retail footprint further in an industry sector that continues to mature and consolidate and provides hedging and diversification benefits to its existing portfolio.
  - Generation continues to pursue investment opportunities in renewables, in its nuclear uprate program and in the development of natural gas generation plants that is supported by the trend of increasing natural gas supply.
- *Investing in business diversification to position the company for the future,*
  - Generation has launched a business in competitive distributed generation that capitalizes on the push toward a decentralized system.
  - Generation is also making investments across the natural gas value chain throughout North America, focusing initially on expansion of the existing Upstream and wholesale gas businesses, as well as entry into liquefied natural gas.

#### Regulated Energy Businesses

The proposed acquisition of PHI provides an opportunity to accelerate Exelon's regulated growth and provide stable cash flows, earnings accretion, and dividend stability. Additionally, ComEd, PECO and BGE anticipate making significant future investments in infrastructure modernization, including smart meter and smart grid initiatives, storm hardening, and advanced reliability technologies. Upon obtaining various approvals, ComEd also plans to invest approximately $280 million to construct the Grand Prairie Gateway Transmission Line in Illinois alleviating identified congestion and enhancing reliability. ComEd, PECO and BGE invest in rate base where it provides a net benefit to customers and the community by increasing reliability and the service experience or otherwise meeting customer needs. These investments are made prudently and at the lowest reasonable cost to customers.

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

### *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 OPEB obligations and invest in new and existing ventures. A broad spectrum of financing alternatives beyond the core financing options can be used to meet its needs and fund growth including monetizing assets in the portfolio via project financing, asset sales, and the use of other financing structures (e.g., joint ventures, minority partners, etc.). 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 $0.5 billion. See Liquidity and Capital Resources—Credit Matters—Exelon Credit Facilities below.

***Exposure to Worldwide Financial Markets.*** Exelon has exposure to worldwide financial markets including European banks. 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, 2014, approximately 29%, or $2.5 billion, of the Registrants' aggregate total commitments were with European banks, excluding the unsecured bridge facility to provide financing for the proposed PHI acquisition. The credit facilities include $8.5 billion in aggregate total commitments of which $7.3 billion was available as of December 31, 2014, due to outstanding letters of credit. There were no borrowings under the Registrants' credit facilities as of December 31, 2014. See Note 13—Debt and Credit Agreements of the Combined Notes to the Consolidated Financial Statements for additional information on the credit facilities.

***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., NOx, SO2 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 tightened ozone NAAQS, to be finalized in late 2015, proposed for public comment in December 2014. These recently finalized or proposed 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. Numerous entities challenged the CSAPR in the D.C. Circuit Court. On August 21, 2012, the D.C. Circuit Court of Appeals 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. On April 29, 2014, the U.S. Supreme Court reversed the D.C. Circuit Court decision and upheld CSAPR, and remanded the case to the D.C. Circuit Court to resolve the remaining implementation issues On November 21, 2014, the U.S. EPA issued an Interim Final Rule in which the Agency announced that it was tolling the effective dates for the CSAPR. The first phase of the CSAPR program started on January 1, 2015, with the second phase starting January 1, 2017. Also released on November 21, 2014, was a Notice of Data Availability under which the Agency proposed CSAPR allowance allocations to generating units for the first five years of the program, 2015-2020; these were identical to those previously identified in prior final rules related to the CSAPR.

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. 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 challenged MATS in the D.C. Circuit Court, and Exelon intervened in support of the rule. On April 15, 2014, the D.C. Circuit Court issued an opinion upholding MATS in its entirety.

In November 2014, the U.S. Supreme Court granted a petition for review of the MATS Rule filed by 20 states and a coalition of coal-fired electric generators. The U.S. Supreme Court announced that it will review a single, yet critical, aspect of the MATS Rule—whether the U.S. EPA properly considered compliance costs (e.g., pollution control capital expenditures and on-going operations and maintenance expense) in determining whether it is appropriate to regulate hazardous air pollutants emitted by electric utilities. If the Court finds that the U.S. EPA acted unreasonably, then implementation of the rule would be delayed until the U.S. EPA corrects any deficiencies. It is likely that the U.S. Supreme Court will issue a decision sometime in 2015. Exelon has been participating in the case as an intervenor in support of the rule.

The U.S. EPA continued its regular, periodic review of the NAAQS standards. On November 25, 2014, the Agency proposed, for public comment, the establishment of a revised primary ozone standard in the range of 65-70 parts per billion (ppb) 8-hour average, a reduction from the 2008 ozone standard level of 75 ppb 8-hour average standard. The Agency is also requesting public comment on levels as low as 60 ppb 8-hour average. In its proposal, the Agency is also proposing to extend the "ozone season" on a state-by-state basis from its current May-September five-month period to include months before, and after, the traditional ozone season, depending on air quality monitoring data. Most CSAPR states are proposed to be subjected to a March to October "ozone season." In its proposed rule, the Agency also elected to set the secondary standard at the same level and form as the primary standard. The Agency is expected to issue its final ozone NAAQS revision in October 2015. 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.

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 SO2 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 March 25, 2015. With regard to Texas and Maryland, no nonattainment areas were identified in EPA's final designation rule. With regard to Illinois and Pennsylvania, several counties, or portions of counties, in each state were identified as nonattainment. Since the 2010 one-hour SO2 standard was finalized, EPA has issued a series of guidance documents, and proposed a Data Requirement Rule that will be finalized in the summer of 2015 related to requirements for states related to the application of air quality monitoring and modeling in state implementation plans. Nonattainment county compliance with the one-hour SO2 standard is required by March 25, 2018. While significant SO2 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 SO2 emissions in support of attainment of the one hour SO2 standard.

The cumulative impact of these air regulations could be to require fossil fuel-fired power plant operators to expend significant capital to install pollution control technologies, including wet flue gas desulfurization technology for SO2 and acid gases, and selective catalytic reduction technology for NOx.

In addition, as of December 31, 2014, Exelon had a $361 million net investment in coal-fired plants in Georgia subject to long-term leases extending through 2028 and 2030. 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 impairments recorded in the second quarter of 2013 and 2014, 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.

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. 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 U.S. EPA 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. The Climate Action Plan also required the U.S. EPA 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. That proposed rule was published in the Federal Register on June 16, 2014. The proposed rule establishes emission reduction targets for each state and provides flexibility for each state to determine how to achieve its required reductions, including heat rate improvements at coal-fired power plants, fuel switching from coal to gas, renewable generation and new nuclear facilities, demand side energy efficiency, and the use of market-based instruments. 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 October 14, 2014, the U.S. EPA's final Section 316(b) rule became effective. The rule requires that a series of studies and analyses be performed at each facility to determine the best technology available, followed by an implementation period. The timing of the various requirements for each facility is related to the status of its current NPDES permit and the subsequent renewal period. There is no fixed compliance schedule, as this is left to the discretion of the state permitting director.

Until the compliance requirements are determined by the applicable state permitting director on a site-specific basis for each plant, the impact of compliance with the final rule is unknown. Should a state permitting director determine that a facility is required to install cooling towers to comply with the rule, that facility's economic viability would be called into question. However, the likely impact of the rule has been significantly decreased since the final rule does not mandate cooling towers as a national standard, and the state permitting director is required to apply a cost-benefit test and take into consideration site-specific factors.

*Hazardous and Solid Waste.* On December 19, 2014, the U.S. EPA issued the first federal regulation for the disposal of coal combustion residuals (CCR) from power plants, including the classification of CCR as non-hazardous waste under RCRA. The EPA ruling is effective 180 days after publication in the Federal Register, which is anticipated in early 2015. Under the regulation, CCR will continue to be regulated by most states subject to coordination with the federal regulations. Generation has previously recorded reserves consistent with state regulation for its owned coal ash sites, and as such, the regulation is not expected to impact Exelon's and Generation's financial results. Generation is evaluating what, if any, incremental costs will be incurred for coal ash disposal sites formerly owned by Generation that have not yet been closed by their current owners. At this time, however, Generation does not have sufficient information to reasonably assess the potential likelihood or magnitude of any remediation requirements that may be asserted for these former sites under the new federal regulations. For these reasons, Generation is unable to predict whether and to what extent they may ultimately be held responsible for remediation and other costs relating to formerly owned coal ash disposal sites under the new regulations, and as a result no new liability has been recorded as of December 31, 2014.

See Note 22—Commitments and Contingencies 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*

***NRC Task Force Insights from the Fukushima Daiichi Accident.*** In July 2011, an NRC Task Force formed in the aftermath of the March 11, 2011, 9.0 magnitude earthquake and ensuing tsunami, that seriously damaged the nuclear units at the Fukushima Daiichi Nuclear Power Station, issued a report of its review of the accident, including tiered 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. 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 Generation, net of expected co-owner reimbursements, for the period from 2015 through 2019 is expected to be between approximately $325 million and $350 million of capital (including approximately $75 million for the CENG plants) and $75 million of operating expense (including approximately $25 million for the CENG plants). 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 thirteen Mark 1 and II units (including two CENG units) for the installation of filters on 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 Management's Discussion and Analysis of Financial Condition and Results of Operations—Executive Overview of the Exelon 2014 Form 10-K, for additional information.

***Financial Reform Legislation.*** The Dodd-Frank Wall Street Reform and Consumer Protection Act (the Act) was enacted in July 2010. The part of the Act that applies to Exelon is Title VII, which is known as the Dodd-Frank Wall Street Transparency and Accountability Act (Dodd-Frank). Dodd-Frank requires the creation of a new regulatory regime for over-the-counter swaps (Swaps), including mandatory clearing for certain categories of Swaps, incentives to shift Swap activity to exchange trading, margin and capital requirements, and other obligations designed to promote transparency. For non security-based Swaps including commodity Swaps, Dodd-Frank empowers the Commodity Futures Trading Commission (CFTC) to promulgate regulations implementing the law's objectives. The primary aim of Dodd-Frank is to regulate the key intermediaries in the Swaps market, which entities are either swap dealers (SDs), major swap participants (MSPs), and certain other financial entities, but the law also applies to a lesser degree to end-users of Swaps. On January 12, 2015, President Obama signed into law a bill that exempts from margin requirements Swaps used by end-users to hedge or mitigate commercial risk. Moreover, the CFTC's Dodd-Frank regulations preserve the ability of end users in the energy industry to hedge their risks using Swaps without being subject to mandatory clearing, and excepts or exempts end-users from many of the other substantive regulations. Accordingly, as an end-user, Generation is conducting its commercial business in a manner that does not require registration with the CFTC as an SD or MSP. Generation does not anticipate transacting in the future in a manner in which it would become a SD or MSP.

There are, however, some rulemakings that have not yet been finalized, including the capital and margin rules for (non-cleared) Swaps. Generation does not expect these rules to directly impact its collateral requirements. However, depending on the substance of these final rules in addition to certain international regulatory requirements still under development and that are similar to Dodd-Frank, Generation's Swap counterparties could be subject to additional and potentially significant capitalization requirements. These regulations could motivate the SDs and MSPs to increase collateral requirements or cash postings from their counterparties, including Generation.

Generation continues to monitor the rulemaking proceedings with respect to the capital and margin rules, but cannot predict to what extent, if any, further refinements to Dodd-Frank requirements may impact its cash flows or financial position, but such impacts could be material.

ComEd, PECO and BGE could also be subject to some Dodd-Frank requirements to the extent they were to enter into Swaps. However, at this time, management of ComEd, PECO and BGE continue to expect that their companies will not be materially affected by Dodd-Frank.

***Energy Infrastructure Modernization Act***. Since 2011, ComEd's distribution rates are established through a performance-based rate formula, pursuant to EIMA. 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. In addition, ComEd's earned rate of return on common equity is required to be within plus or minus 50 basis points ("the collar") of the target rate of return determined as the annual average rate on 30-year treasury notes plus 580 basis points. Therefore, the collar limits favorable and unfavorable impacts of weather and load on distribution revenue. 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 and Annual Reconciliation. On April 16, 2014, ComEd filed its annual distribution formula rate to request a total increase to the revenue requirement of $269 million. On December 11, 2014, the ICC issued its final order which increased the revenue requirement by $232 million, reflecting an increase of $160 million for the initial revenue requirement for 2014 and an increase of $72 million related to the annual reconciliation for 2013. Approximately $23 million of the total $37 million revenue requirement disallowance is recoverable through other rider-based mechanisms. The rate increase was set using an allowed return on capital of 7.06% (inclusive of an allowed return on common equity of 9.25% for 2014 less a performance metrics penalty of 5 basis points for the 2013 reconciliation). The rates took effect in January 2015. ComEd and intervenors requested a rehearing on specific issues, which was denied by the ICC on January 28, 2015.

***Grand Prairie Gateway Transmission Line.*** On December 2, 2013, ComEd filed a request to obtain the ICC's approval to construct a 60-mile overhead 345kV transmission line that traverses Ogle, DeKalb, Kane and DuPage Counties in Northern Illinois. On May 28, 2014, in a separate proceeding, FERC issued an order granting ComEd's request to include 100% of the capital costs recorded to construction work in progress during construction of the line in ComEd's transmission rate base. If the project is cancelled or abandoned for reasons beyond ComEd's control, FERC approved the ability for ComEd to recover 100% of its prudent costs incurred after May 21, 2014 and 50% of its costs incurred prior to May 21, 2014 in ComEd's transmission rate base. On October 22, 2014, the ICC issued an order approving ComEd's Grand Prairie Gateway Project over the objection of numerous landowners and the City of Elgin. Four parties filed timely applications for rehearing before the ICC. On November 25, 2014, the ICC denied the rehearing application filed by the Forest Preserve District of Kane County, but granted rehearing on the application of certain landowners who requested that the ICC consider an alternate route for a three-mile segment of the line in Kane County. The rehearing proceeding is currently pending and , the ICC must enter a final order on rehearing by April 24, 2015. On December 10, 2014, the ICC denied the remaining two applications for rehearing. On January 15, 2015, those two parties, the City of Elgin and the SKP landowner group and Utility Risk Management Corporation (collectively, the SKP/URMC party), each filed a Notice of Appeal with the Second District Appellate Court. On February 3, 2015, the ICC filed motions with the Second District Appellate Court seeking to extend the time for the ICC to file the record on appeal until after the ICC issues its Order on rehearing. The ICC also filed a motion to consolidate those appeals. ComEd expects to begin construction of the line in the second quarter of 2015 with an in-service date expected in the second quarter of 2017.

***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 filed for rehearing of the July 2012 order, which was denied in June 2014. FERC and Ameren are in the process of determining the amount of any potential refund. 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.*** 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 of 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 those PJM Transmission Owners that changes to 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. PJM's compliance filing was made on July 22, 2013. On May 15, 2014, FERC denied the rehearing requests except with respect to one issue on when PJM could consider state and local laws in evaluating projects. FERC generally accepted the July 22, 2013, Compliance Filing but required several minor additional changes. FirstEnergy and at least one other party filed an appeal of the May 15, 2014, Order upholding PJM's right of first refusal language in the DC Circuit. Exelon has intervened in the FirstEnergy appeal. Several parties have filed requests for rehearing or clarification concerning the changes set forth in the May 15, 2014, Order. On December 18, 2014, FERC issued an order conditionally accepting part of the PJM-MISO interregional Order No. 1000 compliance filing, rejecting a MISO proposal concerning cost allocation for cross-border reliability projects and directing a further compliance filing by PJM and MISO.

***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. BGE's formula rate includes a 10.8% base rate of return on common equity (ROE) and a 50 basis point incentive for participating in PJM (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 revenues subject to refund are limited to a fifteen month period, the earliest date from which the base ROE 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.

On August 21, 2014, FERC issued an order in the BGE and PHI companies' proceeding, which established hearing and settlement judge procedures for the complaint, and set a refund effective date of February 27, 2013. BGE, the PHI companies and the parties began settlement discussions under the guidance of a FERC administrative law judge on September 23, 2014. On November 24, 2014, the Settlement Judge informed FERC and the Chief Judge that the parties had reached an impasse and determined that a settlement was not possible. The Settlement Judge recommended termination of settlement proceedings. On November 26, 2014, the Chief Judge issued an order terminating the settlement proceeding, designating a presiding judge at the hearings and directing that an initial decision be issued by November 25, 2015.

On December 8, 2014, various state agencies in Delaware, Maryland, New Jersey, and D.C. filed a second complaint against BGE regarding the base ROE of the transmission business seeking a reduction from 10.8% to 8.8%. The filing of the second complaint creates a second refund window. By order issued on February 9, 2015, FERC established a hearing on the second complaint with the complainants' requested refund effective date of December 8, 2014.

Based on the current status of the complaint filings, BGE believes it is probable that BGE's base ROE rate will be adjusted, and that a refund to customers of transmission revenue for the two maximum fifteen month periods will be required. However, BGE is unable to estimate the most likely refund amount for either complaint at this time, and has therefore established a reserve, which is not material, representing the low end of a reasonably possible estimated range of loss. Additionally, management is unable to estimate the maximum exposure of a potential refund at this time, which may have a material impact on BGE's results of operations and cash flows. The estimated annual ongoing reduction in revenues if FERC approved the ROEs requested by the parties in their filings is approximately $11 million. If FERC were to order a reduction of BGE's base ROE to 8.7% as sought in the first complaint (while retaining the 50 basis points of any incentives that were credited to the base return on equity for certain new transmission investment), the result of the first fifteen month refund window would be a refund to customers of approximately $13 million. If FERC were to order a reduction in BGE's base ROE to 8.8% as sought in the second complaint (while retaining 50 basis points of any incentives that were credited to the base return on equity for certain new transmission investment) and the refund period extended for a full fifteen months, the result would be a refund to customers of approximately $14 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. 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. On January 29, 2014, the MDPSC issued a decision conditionally approving the first five years of BGE's plan and surcharge. On March 26, 2014, the MDPSC approved as filed BGE's proposed 2014 project list, tariff and associated surcharge amounts, with a surcharge that became effective April 1, 2014. On November 17, 2014, BGE filed a surcharge update including a true-up of costs estimates included in the 2014 surcharge, along with its 2015 project list and cost estimates to be included in the 2015 surcharge. The filing was approved with a revised surcharge effective January 1, 2015. At its December 17, 2014 weekly Administrative Meeting, the MDPSC approved BGE's 2015 project list and the proposed surcharge for 2015. BGE will defer the difference between the surcharge revenues and program costs as a regulated asset or liability, which was immaterial to Exelon and BGE as of December 31, 2014.

In February 2014, the residential consumer advocate in Maryland filed an appeal with the Baltimore City Circuit Court to the decision issued by the MDPSC on BGE's infrastructure replacement plan. On September 5, 2014, the Baltimore City Circuit Court affirmed the MDPSC decision on BGE's infrastructure replacement plan and associated surcharge. On October 10, 2014, the residential consumer advocate noticed its appeal to the Maryland Court of Special Appeals from the judgment entered by the Baltimore City Circuit Court, however, a procedural schedule for the matter has not yet been set.

**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**

Generation's ARO associated with decommissioning its nuclear units was $7.0 billion at December 31, 2014. 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. Generation assumes DOE will begin accepting SNF in 2025. The SNF acceptance date was based on management's estimates of the amount of time required for 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—Commitments and Contingencies 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 seventeen 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 has been denied. For its remaining seven operating units, Generation is in various stages of the process of pursuing similar extensions and has filed license renewal applications for six operating nuclear units and has until 2021 to seek license renewal for one operating nuclear unit. 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 seventeen 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 $300 million per unit as of December 31, 2014. 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 $7.0 billion to approximately $8.6 billion. The ultimate decommissioning obligation will be funded by the NDTs. The NDTs are recorded on Exelon's Consolidated Balance Sheets at December 31, 2014 at fair value of approximately $10.5 billion and have an estimated targeted annual pre-tax return of 6.0% to 6.3%.

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 2013 CARFRs rather than the 2014 CARFRs in performing its third quarter 2014 ARO update, Generation would have reduced the ARO by approximately $190 million as compared to the actual decrease to the ARO of $125 million; and ii) if the CARFR used in performing the third quarter 2014 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 $230 million and increased $40 million, respectively, as compared to the actual decrease of $125 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.

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, 2014 |
|---|---|
| **Cost escalation studies** | |
| Uniform increase in escalation rates of 25 basis points | $ 810 |
| **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 | $ 290 |
| Increase the likelihood of the DECON scenario by 10 percentage points and decrease the likelihood of the SAFSTOR scenario by 10 percentage points | $ 420 |
| 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 | $ 630 |
| Extend the estimated date for DOE acceptance of SNF to 2030 | $ 230 |
| Extend the estimated date for DOE acceptance of SNF to 2030 coupled with an increase in discount rates of 100 basis points | $ (270) |
| Extend the estimated date for DOE acceptance of SNF to 2030 coupled with a decrease in discount rates of 100 basis points | $1,100 |

For more information regarding accounting for nuclear decommissioning obligations, see Note 1—Significant Accounting Policies and Note 15—Asset Retirement Obligations of the Combined Notes to Consolidated Financial Statements.

### Goodwill

As of December 31, 2014, Exelon's and ComEd's carrying amount of goodwill was approximately $2.7 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 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 its operating results are 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 operating results are 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 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. 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**

In accordance with the authoritative accounting guidance, the assets acquired and liabilities assumed in an acquired business are recorded at their estimated fair values on the date of acquisition. The difference between the purchase price amount and the net fair value of assets acquired and liabilities assumed 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—Mergers, Acquisitions, and Dispositions of the Combined Notes to Consolidated Financial Statements for additional information.

**Unamortized Energy Assets and Liabilities**

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, Acquisitions, and Dispositions and Note 10—Intangible Assets of the Combined Notes to Consolidated Financial Statements for further discussion.

**Impairment of Long-lived Assets**

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. Indicators for impairment may include a 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 as well as the associated intangible contract assets recorded on the balance sheet. The cash flows from the generating units are generally evaluated at a regional portfolio level with cash flows generated from the 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 generating 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 generating assets (typically contracted renewables).

On a quarterly basis, Generation assesses its asset groups for indicators of impairment. If indicators are present, a recoverability test is performed. Impairment may occur if 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 often 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 judgment, 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 the value of either the long-lived asset or asset group, including any associated intangible contract assets and liabilities, as well as current period earnings by the amount of the impairment.

Generation evaluates natural gas and oil Upstream properties at least annually to determine if they are impaired. Impairment for natural gas and oil Upstream properties occurs if there are no firm plans to continue drilling, lease expiration is at risk, historical experience indicates a decline in carrying value below fair value or the price of the underlying commodity significantly declines.

Exelon holds investments in coal-fired plants in Georgia 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 under the income approach, which uses a discounted cash flow analysis, that 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 contracts associated with the plants given that a market participant would take into consideration all of the terms and conditions contained in the lease agreements.

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 recognizes an impairment, Generation would record its proportionate share of that impairment loss through its equity earnings (losses) of unconsolidated affiliates.

See Note 8—Impairment of Long-Lived Assets 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**

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 Registrants complete depreciation studies every five years, or more frequently in an event, regulation action, or change in retirement patterns indicate an update is necessary. 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—Significant Accounting Policies 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 and filed the updated depreciation rates with both FERC and the ICC in January 2014. This resulted 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. PECO expects to complete an updated depreciation study in 2015 and expects this to result in new depreciation rates effective in the first quarter of 2015 for electric transmission assets and first quarter 2016 for electric distribution and gas assets.

The MDPSC does not mandate the frequency or timing of BGE's depreciation studies. In July 2014, 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 and effective December 15, 2014.

**Defined Benefit Pension and Other Postretirement Benefits**

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 EROA assumption used in calculating pension costs was 7.00%, 7.50% and 7.50% for 2014, 2013 and 2012, respectively. The weighted average EROA assumption used in calculating other postretirement benefit costs was 6.59%, 6.45% and 6.68% in 2014, 2013 and 2012, 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. Over time, Exelon has decreased its equity investments and increased its investments in fixed income securities and alternative investments within the pension asset portfolio 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 6.46% to estimate its 2015 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, 2014 were 10.93% and 5.01%, respectively, compared to an expected long-term return assumption of 7.00% and 6.59%, respectively.

***Discount Rate***. The discount rates used to determine the majority pension and other postretirement benefit obligations were 3.94% and 3.92%, respectively, at December 31, 2014. The discount rates at December 31, 2014 represent weighted-average rates for the majority of pension and other postretirement benefit plans. At December 31, 2014 and 2013, 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 used discount rates ranging from 3.94% and 3.92% to estimate the majority its 2015 pension and other postretirement benefit costs, respectively.

***Health Care Reform Legislation***. In March 2010, the Health Care Reform Acts (the Acts) were signed into law. The 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. Although Exelon has capped the rate of claims growth for certain legacy Exelon plan participants over age 65, exposure to the excise tax remains. 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 under what circumstances pre- and post-65 retiree benefits 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 impact the costs reported for Exelon's other postretirement benefit plans for participant populations with plan designs that do not have a cap on cost growth. 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. Exelon assumed an initial health care cost trend rate of 6.00% for 2014, decreasing to an ultimate health care cost trend rate of 5.00% in 2017.

***Mortality.*** The mortality assumption is composed of a base table that represents the current expectation of life expectancy of the population adjusted by an improvement scale that attempts to anticipate future improvements in life expectancy. Exelon historically used a mortality base table for its accounting valuation that is consistent with the IRS required table for funding (referred to as RP-2000) and its corresponding improvement scale. During 2014, the Society of Actuaries (SOA) issued an updated mortality table (referred to as RP-2014) and improvement scale that suggests significant mortality improvement over the prior table. Exelon has a substantial employee population that provides a credible basis for mortality evaluation. Exelon engaged its actuaries to conduct a mortality study of Exelon's actual experience over a five year period as compared to the RP-2000 and RP-2014 tables, which resulted in a determination that the RP-2000 more closely aligns with Exelon's actual mortality experience. The study also considered available improvement scales. Management concluded that the RP-2000 and a more recent improvement scale issued by the SOA with certain adjustments to long-term improvement rates represent its best estimate of mortality. Exelon is utilizing the Scale BB 2-Dimensional improvement scale with long-term improvements of 0.75% (as compared to the 1% incorporated in the issued table) for its mortality improvement assumption. The change in assumption resulted in increases of $361 million and $117 million in the pension and other postretirement benefits obligations, respectively and an increase in 2015 cost of $45 million and $20 million for pension and other postretirement benefits, respectively.

***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 2014 cost: | | | | |
| Discount rate [a] | 0.5% | $ (71) | $ (34) | $ (105) |
| | (0.5)% | 69 | 31 | 100 |
| EROA | 0.5% | (71) | (12) | (83) |
| | (0.5)% | 71 | 12 | 83 |
| Health care cost trend rate [b] | 1.00% | N/A | 35 | 35 |
| | (1.00)% | N/A | (24) | (24) |
| Change in benefit obligation at December 31, 2014: | | | | |
| Discount rate [a] | 0.5% | (1,053) | (245) | (1,298) |
| | (0.5)% | 1,156 | 271 | 1,427 |
| Health care cost trend rate [b] | 1.00% | N/A | 162 | 162 |
| | (1.00)% | N/A | (113) | (113) |

(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.

(b) Changes in the plan design of certain other postretirement benefit plans have resulted in reduced sensitivity to the health care cost trend rate.

***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, 11.8 years and 11.9 years for the years ended December 31, 2014, 2013 and 2012, 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 9.1 years, 8.7 years and 8.9 years for the years ended December 31, 2014, 2013 and 2012, respectively. The average remaining service period of postretirement benefit plan participants related to expected retirement was 10.1 years, 9.8 years and 10.1 years for the years ended December 31, 2014, 2013 and 2012, respectively.

**Regulatory Accounting**

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, 2014, 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—Regulatory Matters 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**

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—Derivative Financial Instruments 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 the Constellation merger, 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 Constellation 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 Constellation 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 QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK and Note 11—Fair Value of Financial Assets and Liabilities and Note 12—Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information regarding the Registrants' derivative instruments.

**Taxation**

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, 2014 and 2013 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—Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding taxes.

**Accounting for Loss Contingencies**

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—Commitments and Contingencies 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**

***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 and expenses 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 and expenses 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—Accounts Receivable 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**

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 customer risk segment. At December 31, 2013, BGE estimated the allowance for uncollectible accounts on customer receivables by assigning a reserve factor for each aging bucket. These percentages were derived from a study of billing progression which determined the reserve factors by aging bucket. At December 31, 2014, BGE changed to a methodology for estimating the allowance for uncollectible accounts, which was consistent with ComEd and PECO, as described above. 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. 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—Accounts Receivable 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, 2014, 2013 and 2012 set forth below include intercompany transactions, which are eliminated in Exelon's consolidated financial statements.

***Net Income Attributable to Common Shareholders by Registrant***

| | 2014 (b) | 2013 | Favorable (unfavorable) 2014 vs. 2013 variance | 2012 (a) | Favorable (unfavorable) 2013 vs. 2012 variance |
|---|---|---|---|---|---|
| Exelon | $1,623 | $1,719 | $ (96) | $1,160 | $ 559 |
| Generation | 835 | 1,070 | (235) | 562 | 508 |
| ComEd | 408 | 249 | 159 | 379 | (130) |
| PECO | 352 | 388 | (36) | 377 | 11 |
| BGE | 198 | 197 | 1 | (9) | 206 |

(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.

(b) On April 1, 2014, Generation assumed operational control of CENG's nuclear fleet. As a result, the 2014 financial results include CENG's results of operations on a fully consolidated basis from April 1, 2014, through December 31, 2014.

**Results of Operations—Generation**

| | 2014 (c) | 2013 | Favorable (unfavorable) 2014 vs. 2013 variance | 2012 (b) | Favorable (unfavorable) 2013 vs. 2012 variance |
|---|---|---|---|---|---|
| **Operating revenues** | $17,393 | $15,630 | $ 1,763 | $14,437 | $ 1,193 |
| **Purchased power and fuel expense** | 9,925 | 8,197 | (1,728) | 7,061 | (1,136) |
| **Revenue net of purchased power and fuel expense** (a) | 7,468 | 7,433 | 35 | 7,376 | 57 |
| **Other operating expenses** | | | | | |
| Operating and maintenance | 5,566 | 4,534 | (1,032) | 5,028 | 494 |
| Depreciation and amortization | 967 | 856 | (111) | 768 | (88) |
| Taxes other than income | 465 | 389 | (76) | 369 | (20) |
| Total other operating expenses | 6,998 | 5,779 | (1,219) | 6,165 | 386 |
| **Equity in (losses) earnings of unconsolidated affiliates** | (20) | 10 | (30) | (91) | 101 |
| **Gain (loss) on sales of assets** | 437 | 13 | 424 | (7) | 20 |
| **Gain on consolidation and acquisition of businesses** | 289 | — | 289 | — | — |
| **Operating income** | 1,176 | 1,677 | (501) | 1,113 | 564 |
| **Other income and (deductions)** | | | | | |
| Interest expense | (356) | (357) | 1 | (301) | (56) |
| Other, net | 406 | 355 | 51 | 246 | 109 |
| Total other income and (deductions) | 50 | (2) | 52 | (55) | 53 |
| **Income before income taxes** | 1,226 | 1,675 | (449) | 1,058 | 617 |
| **Income taxes** | 207 | 615 | 408 | 500 | (115) |
| **Net income** | 1,019 | 1,060 | (41) | 558 | 502 |
| Net income (loss) attributable to noncontrolling interest | 184 | (10) | 194 | (4) | (6) |
| **Net income attributable to membership interest** | $ 835 | $ 1,070 | $ (235) | $ 562 | $ 508 |

(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.

(c) On April 1, 2014, Generation assumed operational control of CENG's nuclear fleet. As a result, the 2014 financial results include CENG's results of operations on a fully consolidated basis from April 1, 2014 through December 31, 2014.

### *Net Income Attributable to Membership Interest*

*Year Ended December 31, 2014 Compared to Year Ended December 31, 2013.* Generation's net income attributable to membership interest decreased compared to the same period in 2013 primarily due to higher operating and maintenance expense and higher depreciation expense; partially offset by higher revenue, net of purchase power and fuel expense, higher other income, the gains recorded on the sale of Generation's ownership interest in generating stations, the bargain-purchase gain recorded related to the Integrys acquisition, and the gain recorded upon consolidation of CENG. The increase in operating and maintenance expense was largely due to increased labor contracting and materials expense due to the inclusion of CENG's results beginning April 1, 2014 and impairment charges related to 1) generating assets held-for-sale, 2) certain Upstream assets, and 3) wind generating assets. The increase in revenue, net of purchased power and fuel expense was primarily due to the inclusion of CENG's results beginning April 1, 2014, a decrease in fuel costs related to the cancellation of DOE spent nuclear fuel disposal fees, an increase in capacity prices, and favorable portfolio management activities in the New England an South regions, partially offset by lower realized energy prices related to executing Exelon's ratable hedging strategy, higher procurement costs for replacement power due to extreme cold weather in the first quarter of 2014, and unrealized mark-to-market losses in 2014. The increase in other income is primarily the result of increased realized and unrealized gain on NDT funds.

*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 revenue, 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 revenue, net of 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.

***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 gas and oil exploration and production activities, proprietary trading, distributed generation, 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. 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 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 years ended December 31, 2014 compared to 2013 and December 31, 2013 compared to 2012, Generation's revenue net of purchased power and fuel expense by region were as follows:

| | 2014 | 2013 | 2014 vs. 2013 Variance | 2014 vs. 2013 % Change | 2012 (a) | 2013 vs. 2012 Variance | 2013 vs. 2012 % Change |
|---|---|---|---|---|---|---|---|
| Mid-Atlantic (b)(c)(g) | $3,417 | $3,270 | $ 147 | 4.5% | $3,433 | $(163) | (4.7)% |
| Midwest (d) | 2,594 | 2,586 | 8 | 0.3% | 2,998 | (412) | (13.7)% |
| New England | 351 | 185 | 166 | 89.7% | 196 | (11) | (5.6)% |
| New York (b)(g) | 483 | (4) | 487 | n.m. | 76 | (80) | (105.3)% |
| ERCOT | 317 | 436 | (119) | (27.3)% | 405 | 31 | 7.7% |
| Other Regions (e) | 327 | 201 | 126 | 62.7% | 131 | 70 | 53.4% |
| Total electric revenue net of purchased power and fuel expense | 7,489 | 6,674 | 815 | 12.2% | 7,239 | (565) | (7.8)% |
| Proprietary Trading | 42 | (8) | 50 | n.m. | (14) | 6 | 42.9% |
| Mark-to-market gains (losses) | (591) | 504 | (1,095) | n.m. | 515 | (11) | (2.1)% |
| Other (f) | 528 | 263 | 265 | 100.8% | (364) | 627 | n.m. |
| Total revenue net of purchased power and fuel expense | $7,468 | $7,433 | $ 35 | 0.5% | $7,376 | $ 57 | 0.8% |

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

(b) On April 1, 2014, Generation assumed operational control of CENG's nuclear fleet. As a result, the 2014 financial results include CENG's results of operations on a fully consolidated basis from April 1, 2014 through December 31, 2014.

(c) Results of transactions with PECO and BGE are included in the Mid-Atlantic region.

(d) Results of transactions with ComEd are included in the Midwest region.

(e) Other Regions includes South, West and Canada, which are not considered individually significant.

(f) 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 $124 million, $488 million, and $1,098 million pre-tax for the twelve months ended December 31, 2014, December 31, 2013, and December 31, 2012, respectively.

(g) Includes $113 million and $169 million of purchased power from CENG prior to its consolidation on April 1, 2014 in the Mid-Atlantic and New York regions, respectively, for the year ended December 31, 2014. 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—Related Party Transactions of the Combined Notes to Consolidated Financial Statements for additional information.

Generation's supply sources by region are summarized below:

| Supply source (GWh) | 2014 | 2013 | 2014 vs. 2013 Variance | 2014 vs. 2013 % Change | 2012 (a) | 2013 vs. 2012 Variance | 2013 vs. 2012 % Change |
|---|---|---|---|---|---|---|---|
| Nuclear generation (b) | | | | | | | |
| Mid-Atlantic | 58,809 | 48,881 | 9,928 | 20.3% | 47,337 | 1,544 | 3.3% |
| Midwest | 94,000 | 93,245 | 755 | 0.8% | 92,525 | 720 | 0.8% |
| New York | 13,645 | — | 13,645 | n.m. | — | — | — % |
| | 166,454 | 142,126 | 24,328 | 17.1% | 139,862 | 2,264 | 1.6% |
| Fossil and renewables (b) | | | | | | | |
| Mid-Atlantic (b)(d) | 11,025 | 11,714 | (689) | (5.9)% | 8,808 | 2,906 | 33.0% |
| Midwest | 1,372 | 1,478 | (106) | (7.2)% | 971 | 507 | 52.2% |
| New England | 5,233 | 10,896 | (5,663) | (52.0)% | 9,965 | 931 | 9.3% |
| New York | 4 | — | 4 | n.m. | — | — | n.m. |
| ERCOT | 7,164 | 6,453 | 711 | 11.0% | 6,182 | 271 | 4.4% |
| Other Regions (e) | 7,955 | 6,664 | 1,291 | 19.4% | 5,913 | 751 | 12.7% |
| | 32,753 | 37,205 | (4,452) | (12.0)% | 31,839 | 5,366 | 16.9% |
| Purchased power | | | | | | | |
| Mid-Atlantic (c) | 6,082 | 14,092 | (8,010) | (56.8)% | 20,830 | (6,738) | (32.3)% |
| Midwest | 2,004 | 4,408 | (2,404) | (54.5)% | 9,805 | (5,397) | (55.0)% |
| New England | 12,354 | 7,655 | 4,699 | 61.4% | 9,273 | (1,618) | (17.4)% |
| New York (c) | 2,857 | 13,642 | (10,785) | (79.1)% | 11,457 | 2,185 | 19.1% |
| ERCOT | 10,108 | 15,063 | (4,955) | (32.9)% | 23,302 | (8,239) | (35.4)% |
| Other Regions (e) | 14,795 | 14,931 | (136) | (0.9)% | 17,327 | (2,396) | (13.8)% |
| | 48,200 | 69,791 | (21,591) | (30.9)% | 91,994 | (22,203) | (24.1)% |
| Total supply by region (f) | | | | | | | |
| Mid-Atlantic (g) | 75,916 | 74,687 | 1,229 | 1.6% | 76,975 | (2,288) | (3.0)% |
| Midwest (h) | 97,376 | 99,131 | (1,755) | (1.8)% | 103,301 | (4,170) | (4.0)% |
| New England | 17,587 | 18,551 | (964) | (5.2)% | 19,238 | (687) | (3.6)% |
| New York | 16,506 | 13,642 | 2,864 | 21.0% | 11,457 | 2,185 | 19.1% |
| ERCOT | 17,272 | 21,516 | (4,244) | (19.7)% | 29,484 | (7,968) | (27.0)% |
| Other Regions (e) | 22,750 | 21,595 | 1,155 | 5.3% | 23,240 | (1,645) | (7.1)% |
| Total supply | 247,407 | 249,122 | (1,715) | (0.7)% | 263,695 | (14,573) | (5.5)% |

(a) Includes results for Constellation 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 includes the total output of plants that are fully consolidated (e.g. CENG). Nuclear generation for the year ended December 31, 2014 includes physical volumes of 11,408 GWh in Mid-Atlantic and 13,645 GWh in New York for CENG.
(c) Purchased power includes physical volumes of 2,489 GWh, 12,067 GWh, and 9,925 GWh in the Mid-Atlantic and 2,857 GWh, 12,165 GWh, and 9,350 GWh in New York as a result of the PPA with CENG for the years ended December 31, 2014, 2013, and 2012, respectively. On April 1, 2014, Generation assumed operational control of CENG's nuclear fleet. As a result, 100% of CENG volumes are included in nuclear generation.
(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 10,571 GWh, 8,762 GWh, and 12,958 GWh for the years ended December 31, 2014, 2013, and 2012, respectively.
(g) Includes sales to PECO through the competitive procurement process of 2,520 GWh, 5,070 GWh, and 7,762 GWh for the years ended December 31, 2014, 2013, and 2012, respectively. Sales to BGE of 5,093 GWh, 5,595 GWh, and 3,766 GWh were included for the years ended December 31, 2014, 2013, and 2012, respectively.
(h) Includes sales to ComEd under the RFP procurement of 5,259 GWh, 7,491 GWh and 4,152 GWh for the years ended December 31, 2014, 2013, and 2012, respectively.

*Mid-Atlantic*

*Year Ended December 31, 2014 Compared to Year Ended December 31, 2013.* The increase in revenue net of purchased power and fuel expense in the Mid-Atlantic of $147 million was primarily due to the consolidation of CENG, the cancellation of the DOE spent nuclear fuel disposal fees, and favorable portfolio management optimization activities, partially offset by higher procurement costs for replacement power, lower nuclear volumes (excluding CENG), lower capacity revenues, and lower realized energy prices related to executing Generation's ratable hedging strategy.

*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 energy prices and increased nuclear fuel costs, partially offset by the addition of Constellation in 2012, higher capacity revenues, and higher nuclear revenues.

*Midwest*

*Year Ended December 31, 2014 Compared to Year Ended December 31, 2013.* The increase in revenue net of purchased power and fuel expense in the Midwest of $8 million was primarily due to higher capacity prices, higher nuclear volumes, and the cancellation of the DOE spent nuclear fuel disposal fee, partially offset by lower realized energy prices related to executing Generation's ratable hedging strategy.

*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 energy prices, increased nuclear fuel costs, and lower capacity revenues, partially offset by higher nuclear revenues.

*New England*

*Year Ended December 31, 2014 Compared to Year Ended December 31, 2013.* The $166 million increase in revenue net of purchased power and fuel expense in New England is primarily due to higher realized energy prices and favorable impacts from the restructuring of a fuel supply contract, partially offset by lower generation volume.

*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.

*New York*

*Year Ended December 31, 2014 Compared to Year Ended December 31, 2013.* The $487 million increase in revenue net of purchased power and fuel expense in New York was primarily due to the consolidation of CENG.

*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.

*ERCOT*

*Year Ended December 31, 2014 Compared to Year Ended December 31, 2013.* The $119 million decrease in revenue net of purchased power and fuel expense in ERCOT was primarily due to higher procurement costs for replacement power in the second quarter of 2014 and 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. The decreases were partially offset by higher generation volume in the first quarter of 2014.

*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.

*Other Regions*

*Year Ended December 31, 2014 Compared to Year Ended December 31, 2013.* The $126 million increase in revenue net of purchased power and fuel expense in Other Regions was primarily due to higher generation volumes and higher realized energy prices.

*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.

*Mark-to-market*

*Year Ended December 31, 2014 Compared to Year Ended December 31, 2013.* 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 losses on economic hedging activities were $591 million in 2014 compared to gains of $504 million in 2013. See Note 11—Fair Value of Financial Assets and Liabilities and Note 12—Derivative Financial Instruments 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, 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 Note 11—Fair Value of Financial Assets and Liabilities and Note 12—Derivative Financial Instruments 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, 2014 Compared to Year Ended December 31, 2013.* The $265 million increase in other revenue net of purchased power and fuel was primarily due to a reduction in amortization of in-the-money energy contracts recorded at fair value at the Constellation merger date and an increase related to the amortization of out-of-the money energy contracts recorded at fair value upon the consolidation of CENG partially offset by a loss on gas inventory from lower of cost or market adjustments in 2014. See Note 10—Intangible Assets of the Combined Notes to Consolidated Financial Statements for information regarding contract intangibles.

*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 10—Intangible Assets 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 2014, as compared to 2013 and 2012, 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, required capital investment, benefits costs associated with labor, insurance, property taxes, unit contingent costs, suspended DOE nuclear waste storage fee (as discussed further in Note 22—Commitments and Contingencies), 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.

| | 2014 | 2013 | 2012 |
|---|---|---|---|
| Nuclear fleet capacity factor [(a)] | 94.3% | 94.1% | 92.7% |
| Nuclear fleet production cost per MWh [(a)] | $19.33 | $19.83 | $19.50 |

(a) Excludes Salem, which is operated by PSEG Nuclear, LLC. Reflects ownership percentage of stations operated by Exelon. As of April 1, 2014, CENG is included at ownership.

*Year Ended December 31, 2014 Compared to Year Ended December 31, 2013.* The nuclear fleet capacity factor, which excludes Salem, increased in 2014 compared to 2013. While total days offline are greater in 2014 as compared to 2013, the larger capacity units were online for more days in 2014. Additionally, with the addition of the CENG nuclear facilities there were more days offline in 2014 associated with units where Exelon's ownership percentage diminishes the impact on capacity factor. For 2014 and 2013, planned refueling outage days totaled 275 and 233, respectively, and non-refueling outage days totaled 92 and 75, respectively. Production cost per MWh was lower in 2014 compared to 2013 due to elimination of the SNF disposal fee in 2014, partially offset by inclusion of the ownership share of CENG.

*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.

***Operating and Maintenance Expense***

The changes in operating and maintenance expense for 2014 compared to 2013, consisted of the following:

| | Increase (Decrease) [(a)] |
|---|---|
| Impairment and related charges of certain generating assets [(b)] | $ 506 |
| Labor, other benefits, contracting and materials [(c)] | 361 |
| Accretion expense | 78 |
| Corporate allocations [(d)] | 69 |
| Regulatory fees and assessments | 51 |
| Maryland merger commitments | 44 |
| Nuclear refueling outage costs, including the co-owned Salem plant [(e)] | 54 |
| Increase in asbestos bodily injury reserve | 16 |
| Midwest Generation bankruptcy charges | (26) |
| ARO update | (29) |
| Merger and integration costs | (29) |
| Pension and non-pension postretirement benefits expense | (81) |
| Other | 18 |
| Increase in operating and maintenance expense | $1,032 |

(a) On April 1, 2014, Generation assumed operational control of CENG's nuclear fleet. As a result, the 2014 operating results include CENG's results of operations on a fully consolidated basis from April 1, 2014 through December 31, 2014.
(b) Reflects the operating and maintenance expense associated with the impairment of certain generating assets held-for-sale, Upstream assets, and wind generating assets during 2014.
(c) Reflects an increase of labor, other benefits, contracting and materials costs primarily due to the inclusion of CENG beginning April 1, 2014. Also includes cost of sales of our other business activities that are not allocated to a region.
(d) Reflects an increased share of corporate allocated costs primarily due to the 2014 CENG integration.
(e) Reflects the impact of increased nuclear outage days primarily due to the inclusion of CENG beginning April 1, 2014.

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) |
| Asbestos 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 outages during 2013.
(e) The decrease in cost allocations during 2013 primarily reflects merger and energy 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.

***Depreciation and Amortization***

*Year Ended December 31, 2014 Compared to Year Ended December 31, 2013.* The increase in depreciation and amortization expense was primarily due to the inclusion of CENG's results on a fully consolidated basis beginning April 1, 2014 and an increase in ongoing capital expenditures.

*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.

***Taxes Other Than Income***

*Year Ended December 31, 2014 Compared to Year Ended December 31, 2013.* The increase was primarily due to the inclusion of CENG's results on a fully consolidated basis beginning April 1, 2014.

*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.

***Equity in Earnings (Losses) of Unconsolidated Affiliates***

*Year Ended December 31, 2014 Compared to Year Ended December 31, 2013.* The year-over-year change in Equity in earnings (losses) of unconsolidated affiliates is primarily the result of the consolidation of CENG's results of operations beginning April 1, 2014, which were previously accounted for under the equity method of accounting.

***Gain (Loss) on Sales of Assets***

*Year Ended December 31, 2014 Compared to Year Ended December 31, 2013.* The year-over-year change in Gain (loss) on sales of assets reflects $411 million of gains recorded on the sale of Generation's ownership interests in Safe Harbor Water Power Corporation, Fore River and West Valley generating stations in 2014. Refer to Note 4—Mergers, Acquisitions and Dispositions in the Combined Notes to Consolidated Financial Statements for additional information.

*Year Ended December 31, 2013 Compared to Year Ended December 31, 2012.* The year-over-year change in Gain (loss) on sales of assets primarily reflects an $8 million gain recorded on the sale of Maryland Clean Coal in 2013.

***Gain on Consolidation and Acquisition of Businesses***

*Year Ended December 31, 2014 Compared to Year Ended December 31, 2013.* The increase in Gain on consolidation and acquisition of businesses is primarily related to a $261 million gain upon consolidation of CENG resulting from the difference in fair value of CENG's net assets as of April 1, 2014 and the equity method investment previously recorded on Generation's and Exelon's books and the settlement of pre-existing transactions between Generation and CENG, and a $28 million bargain-purchase gain related to the Integrys acquisition.

***Interest Expense***

*Year Ended December 31, 2014 Compared to Year Ended December 31, 2013.* Interest expense for the year ended December 31, 2014 compared to the same period in 2013 remained relatively level.

*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.

***Other, Net***

*Year Ended December 31, 2014 Compared to Year Ended December 31, 2013.* The increase in Other, net primarily reflects $31 million of favorable tax settlements related to Constellation's pre-acquisition 2009-2012 tax returns and the net increase in realized and unrealized gains related to the NDT funds of Generation's Non-Regulatory Agreement Units as described in the table below. Other, net also reflects $67 million and $122 million for the year ended December 31, 2014 and 2013, respectively, related to the contractual elimination of income tax expense associated with the NDT funds of the Regulatory Agreement Units. Refer to Note 15—Asset Retirement Obligations of the Combined Notes to Consolidated Financial Statements for additional information regarding NDT funds.

*Year Ended December 31, 2013 Compared to Year Ended December 31, 2012.* The increase 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. Other, net also reflects $122 million and $117 million for the year ended December 31, 2013 and 2012, respectively, related to the contractual elimination of income tax expense (benefit) associated with the NDT funds of the Regulatory Agreement Units. Refer to Note 15—Asset Retirement Obligations of the Combined Notes to Consolidated Financial Statements for additional information regarding NDT funds.

The following table provides unrealized and realized gains (losses) on the NDT funds of the Non-Regulatory Agreement Units recognized in Other, net for 2014, 2013 and 2012:

| | 2014 | 2013 | 2012 |
|---|---|---|---|
| Net unrealized gains on decommissioning trust funds | $134 | $146 | $105 |
| Net realized gains on sale of decommissioning trust funds | $ 77 | $ 24 | $ 51 |

***Effective Income Tax Rate.***

Generation's effective income tax rates for the years ended December 31, 2014, 2013 and 2012 were 16.9%, 36.7% and 47.3%, 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.

**Results of Operations—ComEd**

| | 2014 | 2013 | Favorable (Unfavorable) 2014 vs. 2013 Variance | 2012 | Favorable (Unfavorable) 2013 vs. 2012 Variance |
|---|---|---|---|---|---|
| **Operating revenue** | $4,564 | $4,464 | $ 100 | $5,443 | $ (979) |
| **Purchased power expense** | 1,177 | 1,174 | (3) | 2,307 | 1,133 |
| **Revenue net of purchased power expense** (a) | 3,387 | 3,290 | 97 | 3,136 | 154 |
| **Other operating expenses** | | | | | |
| Operating and maintenance | 1,429 | 1,368 | (61) | 1,345 | (23) |
| Depreciation and amortization | 687 | 669 | (18) | 610 | (59) |
| Taxes other than income | 293 | 299 | 6 | 295 | (4) |
| Total other operating expenses | 2,409 | 2,336 | (73) | 2,250 | (86) |
| **Gain on sales of assets** | 2 | — | 2 | — | — |
| **Operating income** | 980 | 954 | 26 | 886 | 68 |
| **Other income and (deductions)** | | | | | |
| Interest expense, net | (321) | (579) | 258 | (307) | (272) |
| Other, net | 17 | 26 | (9) | 39 | (13) |
| Total other income and (deductions) | (304) | (553) | 249 | (268) | (285) |
| **Income before income taxes** | 676 | 401 | 275 | 618 | (217) |
| **Income taxes** | 268 | 152 | (116) | 239 | 87 |
| **Net income** | $ 408 | $ 249 | $ 159 | $ 379 | $ (130) |

(a) ComEd evaluates its operating performance using the measure of revenue net of purchased power expense. ComEd believes that revenue 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 revenue net of purchased power expense below as a complement to the financial information provided in accordance with GAAP. However, revenue 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, 2014, Compared to Year Ended December 31, 2013.* ComEd's Net income for the year ended December 31, 2014, was higher than the same period in 2013, primarily due to the 2013 remeasurement of Exelon's like-kind exchange tax position, and increased electric distribution and transmission earnings resulting from increased capital investment, partially offset by unfavorable weather.

*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 and unfavorable weather, partially offset by increased electric distribution and transmission earnings resulting from increased costs and capital investments and higher allowed ROE. See Note 3—Regulatory Matters and Note 14—Income Taxes of the Combined Notes to Consolidated Financial Statements in the 2013 10-K for additional information.

***Operating Revenue Net of Purchased Power Expense***

There are certain drivers of Operating revenue 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 Revenue 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 revenue related to supplied energy, which is fully offset in Purchased power expense. Therefore, customer choice programs have no impact on Revenue net of purchased power expense.

The number of retail customers participating in customer choice programs was 2,426,921, 2,630,185 and 1,627,150 at December 31, 2014, 2013 and 2012, respectively, representing 63%, 68% and 43% of total retail customers, respectively. Retail energy purchased from competitive electric generation suppliers represented 80%, 81% and 65% of ComEd's retail kWh sales for the years ended December 31, 2014, 2013 and 2012, respectively.

The changes in ComEd's Revenue net of purchased power expense for the year ended 2014 compared to the same period in 2013 consisted of the following:

| | Increase |
|---|---|
| Weather | $(16) |
| Electric distribution revenue | (2) |
| Transmission revenue | 30 |
| Regulatory required programs | 52 |
| Revenue subject to refund | (9) |
| Pricing and customer mix | 5 |
| Uncollectible accounts recovery, net | 41 |
| Other | (4) |
| Increase in revenue net of purchased power | $ 97 |

*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, 2014, unfavorable weather conditions, primarily during the summer months, reduced Operating revenue net of purchased power expense when compared to prior year.

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, 2014 and 2013 consisted of the following:

| | Twelve Months Ended December 31, | | | % Change | |
|---|---|---|---|---|---|
| **Heating and Cooling Degree-Days** | **2014** | **2013** | **Normal** | **From 2013** | **From Normal** |
| Heating Degree-Days | 7,027 | 6,603 | 6,341 | 6.4% | 10.8% |
| Cooling Degree-Days | 799 | 933 | 842 | (14.4)% | (5.1)% |

*Volume*

For the year ended December 31, 2014 Revenue net of purchased power expense remained relatively consistent, as compared to the same period in 2013.

*Electric Distribution Revenue*

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. Under EIMA, distribution revenue varies from year to year based upon fluctuations in the underlying costs, investments being recovered, allowed ROE, and other billing determinants. In addition, ComEd's allowed rate of return on common equity is the annual average rate on 30-year treasury notes plus 580 basis points, subject to a collar of plus or minus 50 basis points. Therefore, the collar limits favorable and unfavorable impacts of weather and load on revenue. During the year ended December 31, 2014, distribution revenue decreased $2 million at ComEd, primarily due to lower Operating and maintenance expenses primarily driven by the impacts of certain OPEB plan design changes, partially offset by increased capital investment. See Operating and Maintenance Expense below, Note 3—Regulatory Matters and Note 16—Retirement Benefits of the Combined Notes to Consolidated Financial Statements for additional information.

*Transmission Revenue*

Under a FERC approved formula, transmission revenue varies 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, 2014, ComEd recorded increased revenue of $30 million due to increased capital investments. See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

*Regulatory Required Programs*

This represents the change in Operating revenue collected under approved riders to recover costs incurred for regulatory programs such as ComEd's energy efficiency and demand response and purchase power administrative costs. The riders are designed to provide full and current cost recovery. The costs of these programs are included in Operating and maintenance expense. Refer to the Operating and maintenance expense discussion below for additional information on included programs.

*Uncollectible Accounts Recovery, Net*

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.

*Pricing and Customer Mix*

The increase in Revenue net of purchased power as a result of pricing and customer mix is primarily attributable to higher overall effective rates due to decreased usage across all major customer classes and change in customer mix for the years ended December 31, 2014, and 2013, respectively.

*Revenue Subject to Refund*

ComEd records revenue subject to refund based upon its best estimate of customer collections that may be required to be refunded. For the year ended December 31, 2014, ComEd recorded $9 million of revenue subject to refund associated with Rider AMP. See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial statements for additional information.

*Other*

Other revenue, which can vary period to period, includes rental revenue, revenue related to late payment charges, assistance provided to other utilities through mutual assistance programs and recoveries of environmental costs associated with MGP sites, recovery of energy procurement costs, for which an equal and offsetting amount is reflected in Depreciation and amortization expense during the periods presented.

The changes in ComEd's Revenue net of purchased power expense for 2013 compared to 2012 consisted of the following:

| | Increase |
|---|---|
| Weather | $ (17) |
| Volume | (2) |
| Electric distribution revenue | 168 |
| Discrete impacts of the 2012 distribution rate case order | 13 |
| Transmission revenue | 14 |
| Regulatory required programs | 20 |
| Uncollectible accounts recovery, net | (58) |
| Other | 16 |
| Increase in revenue net of purchased power | $154 |

*Weather*

For the year ended December 31, 2013, the increase in Revenue 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.

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 | Twelve Months Ended December 31, 2013 | 2012 | Normal | % Change 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*

Revenue 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 Revenue*

During the year ended December 31, 2013, ComEd recorded increased revenue of $168 million under EIMA, primarily due to increased capital investments, increased operating expenses, and higher allowed ROE. 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, which reestablished ComEd's position on the return on its pension asset, resulting in an increase to revenue in 2013. See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

*Transmission Revenue*

During the year ended December 31, 2013, ComEd recorded increased revenue during the year ended December 31, 2013 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.

***Operating and Maintenance Expense***

| | Year Ended December 31, 2014 | 2013 | Increase 2014 vs. 2013 | Year Ended December 31, 2013 | 2012 | Increase 2013 vs. 2012 |
|---|---|---|---|---|---|---|
| Operating and maintenance expense—baseline | $1,211 | $1,202 | $ 9 | $1,202 | $1,199 | $ 3 |
| Operating and maintenance expense—regulatory required programs [(a)] | 218 | 166 | 52 | 166 | 146 | 20 |
| Total operating and maintenance expense | $1,429 | $1,368 | $61 | $1,368 | $1,345 | $23 |

(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 revenue.

The changes in Operating and maintenance expense for year ended December 31, 2014, compared to the same period in 2013 and changes for the year ended December 31, 2013, compared to the same period in 2012, consisted of the following:

| | Increase 2014 vs. 2013 | Increase 2013 vs. 2012 |
|---|---|---|
| Baseline | | |
| Labor, other benefits, contracting and materials (a) | $ 56 | $ 48 |
| Pension and non-pension postretirement benefits expense (b) | (85) | 3 |
| Storm-related costs | (11) | (10) |
| Uncollectible accounts expense—provision (c) | 12 | (10) |
| Uncollectible accounts expense—recovery, net (c) | 29 | (48) |
| Other | 8 | 20 |
| | 9 | 3 |
| Regulatory required programs | | |
| Energy efficiency and demand response programs | 52 | 20 |
| Increase in operating and maintenance expense | $ 61 | $ 23 |

(a) Reflects decreased contracting costs resulting from new projects associated with EIMA for the years ended December 31, 2014 and 2013. See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information regarding EIMA.

(b) Primarily reflects decreased non-pension costs associated with OPEB plan design changes during 2014. See Note 16—Retirement Benefits of the Combined Notes to the Consolidated Financial Statements for additional information regarding plan changes.

(c) 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 revenue for the periods presented.

***Depreciation and Amortization Expense***

The changes in Depreciation and amortization expense for 2014 compared to 2013 and 2013 compared to 2012, consisted of the following:

| | Increase 2014 vs. 2013 | Increase 2013 vs. 2012 |
|---|---|---|
| Depreciation associated with higher plant balances | $ 46 | $ 22 |
| Amortization of storm-related regulatory assets (a) | — | 4 |
| Amortization of MGP regulatory assets (b) | (18) | 27 |
| Amortization of other regulatory assets | (3) | 6 |
| Other | (7) | — |
| Increase in depreciation and amortization expense | $ 18 | $ 59 |

(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 revenue during the periods presented.

***Taxes Other Than Income***

*Year Ended December 31, 2014 Compared to Year Ended December 31, 2013.* 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 remained relatively flat for the twelve months ended December 31, 2014, compared to the same periods in 2013.

*Year Ended December 31, 2013 Compared to Year Ended December 31, 2012.* Taxes other than income taxes increased primarily due to increased Illinois electricity distribution taxes.

***Interest Expense, Net***

The changes in Interest expense, net for 2014 compared to 2013 and 2013 compared to 2012 consisted of the following:

| | Increase (Decrease) 2014 vs. 2013 | Increase (Decrease) 2013 vs. 2012 |
|---|---|---|
| Interest expense related to uncertain tax positions [(a)] | $(275) | $281 |
| Interest expense on debt (including financing trusts) [(b)] | 16 | 2 |
| Other | 1 | (11) |
| Increase (decrease) in interest expense, net | $(258) | $272 |

(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.
(b) Primarily reflects interest expense related to the First Mortgage Bonds. See Note 13—Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information on ComEd's debt obligations.

***Other, Net***

The changes in Other, net for 2014 compared to 2013 and 2013 compared to 2012 consisted of the following:

| | Increase (Decrease) 2014 vs. 2013 | Increase (Decrease) 2013 vs. 2012 |
|---|---|---|
| Interest income related to uncertain tax positions [(a)] | $— | $(20) |
| AFUDC—Equity | (8) | — |
| Other | (1) | 7 |
| Increase (decrease) in Other, net | $ (9) | $(13) |

(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, 2014, 2013 and 2012, were 39.6%, 37.9% and 38.7%, 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.

***ComEd Electric Operating Statistics and Revenue Detail***

| Retail Deliveries to customers (in GWhs) | 2014 | 2013 | % Change 2014 vs 2013 | Weather-Normal % Change | 2012 | % Change 2013 vs 2012 | Weather-Normal % Change |
|---|---|---|---|---|---|---|---|
| **Retail Deliveries** [(a)] | | | | | | | |
| Residential | 27,230 | 27,800 | (2.1)% | 0.3% | 28,528 | (2.6)% | (0.6)% |
| Small commercial & industrial | 32,146 | 32,305 | (0.5)% | (0.3)% | 32,534 | (0.7)% | 0.2% |
| Large commercial & industrial | 27,847 | 27,684 | 0.6% | 0.7% | 27,643 | 0.1% | (0.3)% |
| Public authorities & electric railroads | 1,358 | 1,355 | 0.2% | (0.7)% | 1,272 | 6.5% | 4.2% |
| Total retail deliveries | 88,581 | 89,144 | (0.6)% | 0.2% | 89,977 | (0.9)% | (0.1)% |

| Number of Electric Customers | As of December 31, 2014 | 2013 | 2012 |
|---|---|---|---|
| Residential | 3,502,386 | 3,480,398 | 3,455,546 |
| Small commercial & industrial | 369,053 | 367,569 | 365,357 |
| Large commercial & industrial | 1,998 | 1,984 | 1,980 |
| Public authorities & electric railroads | 4,815 | 4,853 | 4,812 |
| Total | 3,878,252 | 3,854,804 | 3,827,695 |

| Electric Revenue | 2014 | 2013 | % Change 2014 vs 2013 | 2012 | % Change 2013 vs 2012 |
|---|---|---|---|---|---|
| **Retail Sales** [(a)] | | | | | |
| Residential | $2,074 | $2,073 | — % | $3,037 | (31.7)% |
| Small commercial & industrial | 1,335 | 1,250 | 6.8% | 1,339 | (6.6)% |
| Large commercial & industrial | 434 | 427 | 1.6% | 395 | 8.1% |
| Public authorities & electric railroads | 46 | 48 | (4.2)% | 44 | 9.1% |
| Total retail sales | 3,889 | 3,798 | 2.4% | 4,815 | (21.1)% |
| Other revenue [(b)] | 675 | 666 | 1.4% | 628 | 6.1% |
| Total electric revenue | $4,564 | $4,464 | 2.2% | $5,443 | (18.0)% |

(a) Reflects delivery revenue and volume 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, revenue 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 revenue.

**Results of Operations—PECO**

| | 2014 | 2013 | Favorable (unfavorable) 2014 vs. 2013 variance | 2012 | Favorable (unfavorable) 2013 vs. 2012 variance |
|---|---|---|---|---|---|
| **Operating revenue** | $3,094 | $3,100 | $ (6) | $3,186 | $(86) |
| Purchased power and fuel | 1,261 | 1,300 | 39 | 1,375 | 75 |
| **Revenue net of purchased power and fuel expense** [(a)] | 1,833 | 1,800 | 33 | 1,811 | (11) |
| **Other operating expenses** | | | | | |
| Operating and maintenance | 866 | 748 | (118) | 809 | 61 |
| Depreciation and amortization | 236 | 228 | (8) | 217 | (11) |
| Taxes other than income | 159 | 158 | (1) | 162 | 4 |
| Total other operating expenses | 1,261 | 1,134 | (127) | 1,188 | 54 |
| **Operating income** | 572 | 666 | (94) | 623 | 43 |
| **Other income and (deductions)** | | | | | |
| Interest expense, net | (113) | (115) | 2 | (123) | 8 |
| Other, net | 7 | 6 | 1 | 8 | (2) |
| Total other income and (deductions) | (106) | (109) | 3 | (115) | 6 |
| **Income before income taxes** | 466 | 557 | (91) | 508 | 49 |
| **Income taxes** | 114 | 162 | 48 | 127 | (35) |
| **Net income** | 352 | 395 | (43) | 381 | 14 |
| Preferred security dividends and redemption | — | 7 | 7 | 4 | (3) |
| **Net income attributable to common shareholder** | $ 352 | $ 388 | $ (36) | $ 377 | $ 11 |

(a) PECO evaluates its operating performance using the measures of revenue net of purchased power expense for electric sales and revenue net of fuel expense for gas sales. PECO believes revenue net of purchased power expense and revenue net of fuel expense are useful measurements of its performance because they provide information that can be used to evaluate its net revenue from operations. PECO has included the analysis below as a complement to the financial information provided in accordance with GAAP. However, revenue 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 Attributable to Common Shareholder***

*Year Ended December 31, 2014 Compared to Year Ended December 31, 2013.* The decrease in Net income attributable to common shareholder was driven primarily by an increase in Operating and maintenance expense partially offset by an increase in Operating revenue net of purchase power and fuel expense and a decrease in Income tax expense.

*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.

***Operating Revenue Net of Purchased Power and Fuel Expense***

Electric and gas revenue 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 revenue net of purchased power and fuel expense.

Electric and gas revenue 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 revenue collected from customers related to supplied energy and natural gas service. Customer Choice Program activity has no impact on electric and gas revenue net of purchase power and fuel expense. The number of retail customers purchasing energy from a competitive electric generation supplier was 546,900, 531,500, and 496,500 at December 31, 2014, 2013 and 2012, respectively. Retail deliveries purchased from competitive electric generation suppliers represented 70%, 68%, and 66% of PECO's retail kWh sales for the years ended December 31, 2014, 2013 and 2012, respectively. The number of retail customers purchasing natural gas from a competitive natural gas supplier was 78,400, 66,400, and 52,700 at December 31, 2014, 2013 and 2012, respectively. Retail deliveries purchased from competitive natural gas suppliers represented 22%, 19%, and 16% of PECO's mmcf sales for the years ended December 31, 2014, 2013 and 2012, respectively.

The changes in PECO's Operating revenue net of purchased power and fuel expense for the year ended December 31, 2014 compared to the same period in 2013 consisted of the following:

| | Increase | | |
|---|---|---|---|
| | Electric | Gas | Total |
| Weather | $(15) | $ 13 | $ (2) |
| Volume | 2 | 5 | 7 |
| Pricing | (1) | (3) | (4) |
| Regulatory required programs | 33 | — | 33 |
| Other | (1) | — | (1) |
| Total increase | $ 18 | $ 15 | $33 |

*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 revenue net of purchased power and fuel expense was lower due to the impact of unfavorable 2014 summer and fourth quarter weather conditions, partially offset by the impact of favorable first quarter 2014 winter weather conditions in PECO's service territory.

Heating and cooling degree days are quantitative indices that reflect the demand for energy needed to heat or cool a home or business. Normal weather is determined based on historical average heating and cooling degree days for a 30-year period in PECO's service territory. The changes in heating and cooling degree days in PECO's service territory for the year ended December 31, 2014 compared to the same period in 2013 and normal weather consisted of the following:

| | Twelve Months Ended December 31, | | | % Change | |
|---|---|---|---|---|---|
| **Heating and Cooling Degree-Days** | **2014** | **2013** | **Normal** | **From 2013** | **From Normal** |
| Heating Degree-Days | 4,749 | 4,474 | 4,603 | 6.1% | 3.2% |
| Cooling Degree-Days | 1,311 | 1,411 | 1,301 | (7.1)% | 0.8% |

*Volume*

The increase in Operating revenue net of purchased power and fuel expense related to delivery volume, exclusive of the effects of weather, primarily reflects the impact of moderate economic and customer growth partially offset by energy efficiency initiatives on customer usages for gas and residential electric and a shift in the volume profile across classes from commercial and industrial classes to residential classes for electric.

*Pricing*

The decrease in gas operating revenue net of fuel expense as a result of pricing is primarily attributable to lower overall effective rates due to increased retail gas usage.

*Regulatory Required Programs*

This represents the change in operating revenue collected under approved riders to recover costs incurred for regulatory programs such as smart meter, energy efficiency and the GSA. The riders are designed to provide full and current cost recovery as well as a return. The costs of these programs are included in 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.

The changes in PECO's operating revenue 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 increase (decrease) | $(32) | $ 21 | $(11) |

*Weather*

Operating revenue net of purchased power and fuel expense were higher due to the impact of favorable 2013 winter weather conditions.

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:

| | Twelve Months Ended December 31, | | | % Change | |
|---|---|---|---|---|---|
| **Heating and Cooling Degree-Days** | **2013** | **2012** | **Normal** | **From 2012** | **From Normal** |
| 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 revenue net of purchased power expense related to delivery volume, exclusive of the effects of weather, reflected the impact of energy efficiency initiatives on customer usages as well as a shift in the volume profile across classes from residential classes to commercial and industrial classes, partially offset by the oil refineries returning to full production in 2013 as well as moderate economic growth. The decrease in gas revenue net of fuel expense related to delivery volume, exclusive of the effects of weather, primarily reflected a decline in residential use per customer.

*Pricing*

The decrease in electric operating revenue 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 revenue 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 revenue. As a result of decreases in operating revenue 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 reflected 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 revenue, see Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for further explanation.

*Other*

The decrease in other electric revenue net of purchased power expense compared to the year ended December 31, 2012 reflected a decrease in wholesale transmission revenue earned by PECO due to higher peak loads in the previous years.

***Operating and Maintenance Expense***

| | Twelve Months Ended December 31, | | Increase | Twelve Months Ended December 31, | | (Decrease) |
|---|---|---|---|---|---|---|
| | 2014 | 2013 | 2014 vs. 2013 | 2013 | 2012 | 2013 vs. 2012 |
| Operating and maintenance expense—baseline | $761 | $668 | $ 93 | $668 | $723 | $(55) |
| Operating and maintenance expense—regulatory required programs [(a)] | 105 | 80 | $ 25 | 80 | 86 | $ (6) |
| Total operating and maintenance expense | $866 | $748 | $118 | $748 | $809 | $(61) |

(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 revenue.

The changes in Operating and maintenance expense for 2014 compared to 2013 and 2013 compared to 2012 consisted of the following:

| | Increase (Decrease) 2014 vs. 2013 | Increase (Decrease) 2013 vs. 2012 |
|---|---|---|
| Baseline | | |
| Labor, other benefits, contracting and materials | $ 12 | $ 10 |
| Storm-related costs | 100[a] | (49) |
| Pension and non-pension postretirement benefits expense | (5) | (12) |
| Merger and integration costs | (7) | (8) |
| Corporate allocation | 5 | — |
| Uncollectible accounts expense | (9) | — |
| Other | (3) | 4 |
| | 93 | (55) |
| Regulatory required programs | | |
| Smart meter | 7 | 4 |
| Energy efficiency | 17 | (9) |
| Consumer education program | — | (1) |
| Other | 1 | — |
| | 25 | (6) |
| Increase (decrease) in operating and maintenance expense | $118 | $(61) |

(a) Total storm-related costs include approximately $85 million of incremental storm costs, including the February 5, 2014 ice storm and the significant July storms.

### *Depreciation and Amortization Expense*

*Year Ended December 31, 2014 Compared to Year Ended December 31, 2013.* The increase in Depreciation and amortization expense, net for 2014, compared to 2013 was primarily due to ongoing capital expenditures and regulatory required programs.

*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.

### *Taxes Other Than Income*

*Year Ended December 31, 2014 Compared to Year Ended December 31, 2013.* Taxes other than income remained relatively consistent.

*Year Ended December 31, 2013 Compared to Year Ended December 31, 2012.* The decrease in Taxes other than income for 2013 compared to 2012 was primarily due to GRT expense slightly offset by sales and use tax.

### *Interest Expense, Net*

*Year Ended December 31, 2014 Compared to Year Ended December 31, 2013.* Interest expense, net remained relatively consistent.

*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.

### *Other, Net*

*Year Ended December 31, 2014 Compared to Year Ended December 31, 2013.* Other, net remained relatively consistent.

*Year Ended December 31, 2013 Compared to Year Ended December 31, 2012.* Other, net remained relatively consistent.

***Effective Income Tax Rate***

PECO's effective income tax rates for the years ended December 31, 2014, 2013 and 2012 were 24.5%, 29.1% and 25.0%, respectively. See Note 14—Income Taxes of the Combined Notes to Consolidated Financial Statements for further discussion of the change in effective income tax rates.

***PECO Electric Operating Statistics and Revenue Detail***

| Retail Deliveries to customers (in GWhs) | 2014 | 2013 | % Change 2014 vs. 2013 | Weather-Normal % Change | 2012 | % Change 2013 vs. 2012 | Weather-Normal % Change |
|---|---|---|---|---|---|---|---|
| **Retail Deliveries** (a) | | | | | | | |
| Residential | 13,222 | 13,341 | (0.9)% | 0.5% | 13,233 | 0.8% | — % |
| Small commercial & industrial | 8,025 | 8,101 | (0.9)% | — % | 8,063 | 0.5% | (1.1)% |
| Large commercial & industrial | 15,310 | 15,379 | (0.4)% | (0.1)% | 15,253 | 0.8% | 1.5% |
| Public authorities & electric railroads | 937 | 930 | 0.8% | 0.8% | 943 | (1.4)% | (1.4)% |
| Total electric retail deliveries | 37,494 | 37,751 | (0.7)% | 0.1% | 37,492 | 0.7% | 0.3% |

| Number of Electric Customers | As of December 31, 2014 | 2013 | 2012 |
|---|---|---|---|
| Residential | 1,434,011 | 1,423,068 | 1,417,773 |
| Small commercial & industrial | 149,149 | 149,117 | 148,803 |
| Large commercial & industrial | 3,103 | 3,105 | 3,111 |
| Public authorities & electric railroads | 9,734 | 9,668 | 9,660 |
| Total | 1,595,997 | 1,584,958 | 1,579,347 |

| Electric Revenue | 2014 | 2013 | % Change 2014 vs. 2013 | 2012 | % Change 2013 vs. 2012 |
|---|---|---|---|---|---|
| **Retail Sales** (a) | | | | | |
| Residential | $1,555 | $1,592 | (2.3)% | $1,689 | (5.7)% |
| Small commercial & industrial | 423 | 433 | (2.3)% | 462 | (6.3)% |
| Large commercial & industrial | 217 | 224 | (3.1)% | 232 | (3.4)% |
| Public authorities & electric railroads | 32 | 30 | 6.7% | 31 | (3.2)% |
| Total retail | 2,227 | 2,279 | (2.3)% | 2,414 | (5.6)% |
| Other revenue (b) | 221 | 221 | — % | 226 | (2.2)% |
| Total electric revenue | $2,448 | $2,500 | (2.1)% | $2,640 | (5.3)% |

(a) Reflects delivery volumes and revenue 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 reflect the cost of energy and transmission.

(b) Other revenue includes transmission revenue from PJM and wholesale electric revenue.

***PECO Gas Operating Statistics and Revenue Detail***

| Deliveries to customers (in mmcf) | 2014 | 2013 | % Change 2014 vs. 2013 | Weather-Normal % Change | 2012 | % Change 2013 vs. 2012 | Weather-Normal % Change |
|---|---|---|---|---|---|---|---|
| **Retail Deliveries** (a) | | | | | | | |
| Retail sales | 62,734 | 57,613 | 8.9% | 2.2% | 49,767 | 15.8% | (0.1)% |
| Transportation and other | 27,208 | 28,089 | (3.1)% | (1.0)% | 26,687 | 5.3% | 0.5% |
| Total gas deliveries | 89,942 | 85,702 | 4.9% | 1.2% | 76,454 | 12.1% | 0.1% |

| Number of Gas Customers | As of December 31, 2014 | 2013 | 2012 |
|---|---|---|---|
| Residential | 462,663 | 458,356 | 454,502 |
| Commercial & industrial | 42,686 | 42,174 | 41,836 |
| Total retail | 505,349 | 500,530 | 496,338 |
| Transportation | 855 | 909 | 903 |
| Total | 506,204 | 501,439 | 497,241 |

| Gas revenue | 2014 | 2013 | % Change 2014 vs. 2013 | 2012 | % Change 2013 vs. 2012 |
|---|---|---|---|---|---|
| **Retail Sales** [(a)] | | | | | |
| Retail sales | $608 | $562 | 8.2% | $509 | 10.4% |
| Transportation and other | 38 | 38 | — % | 37 | 2.7% |
| Total gas revenue | $646 | $600 | 7.7% | $546 | 9.9% |

(a) Reflects delivery volumes and revenue 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 reflect the cost of natural gas.

**Results of Operations—BGE**

| | 2014 | 2013 | Favorable (unfavorable) 2014 vs. 2013 variance | 2012 | Favorable (unfavorable) 2013 vs. 2012 variance |
|---|---|---|---|---|---|
| **Operating revenue** | $3,165 | $3,065 | $ 100 | $2,735 | $ 330 |
| Purchased power and fuel expense | 1,417 | 1,421 | 4 | 1,369 | (52) |
| **Revenue net of purchased power and fuel expense** [(a)] | 1,748 | 1,644 | 104 | 1,366 | 278 |
| **Other operating expenses** | | | | | |
| Operating and maintenance | 717 | 634 | (83) | 728 | 94 |
| Depreciation and amortization | 371 | 348 | (23) | 298 | (50) |
| Taxes other than income | 221 | 213 | (8) | 208 | (5) |
| Total other operating expenses | 1,309 | 1,195 | (114) | 1,234 | 39 |
| **Operating income** | 439 | 449 | (10) | 132 | 317 |
| **Other income and (deductions)** | | | | | |
| Interest expense, net | (106) | (122) | 16 | (144) | 22 |
| Other, net | 18 | 17 | 1 | 23 | (6) |
| Total other income and (deductions) | (88) | (105) | 17 | (121) | 16 |
| **Income before income taxes** | 351 | 344 | 7 | 11 | 333 |
| **Income taxes** | 140 | 134 | (6) | 7 | (127) |
| **Net income** | 211 | 210 | 1 | 4 | 206 |
| Preference stock dividends | 13 | 13 | — | 13 | — |
| **Net income (loss) attributable to common shareholder** | $ 198 | $ 197 | $ 1 | $ (9) | $ 206 |

(a) BGE evaluates its operating performance using the measures of revenue net of purchased power expense for electric sales and revenue net of fuel expense for gas sales. BGE believes revenue 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 revenue from operations. BGE has included the analysis below as a complement to the financial information provided in accordance with GAAP. However, revenue 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 (Loss) Attributable to Common Shareholder***

*Year Ended December 31, 2014 Compared to Year Ended December 31, 2013.* Net income attributable to common shareholder remained relatively consistent primarily due to an increase in Revenue net of purchased power and fuel expense as a result of the December 2013 and 2014 electric and gas distribution rate order issued by the MDPSC offset by increases in Operating and maintenance expense and Depreciation expense.

*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 Revenue 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.

***Operating Revenue 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 revenue 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 revenue and purchased power expense. The number of customers electing to select a competitive natural gas supplier affects gas cost adjustment revenue 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 364,000, 399,000 and 362,000 at December 31, 2014, 2013 and 2012, respectively, representing 29%, 32% and 29% of total retail customers, respectively. Retail deliveries purchased from competitive electric generation suppliers represented 60%, 61% and 60% of BGE's retail kWh sales for the years ended December 31, 2014, 2013 and 2012, respectively. The number of retail customers purchasing natural gas from a competitive natural gas supplier was 161,000, 172,000 and 143,000 at December 31, 2014, 2013 and 2012, respectively, representing 25%, 26% and 22% of total retail customers, respectively. Retail deliveries purchased from competitive natural gas suppliers represented 53%, 54% and 56% of BGE's retail mmcf sales for the years ended December 31, 2014, 2013 and 2012, respectively.

The changes in BGE's Operating revenue net of purchased power and fuel expense for the year ended December 31, 2014 compared to the same period in 2013 consisted of the following:

| | Increase (Decrease) | | |
|---|---|---|---|
| | Electric | Gas | Total |
| Distribution rate increases | $ 57 | $ 28 | $ 85 |
| Commodity margin | (1) | 12 | 11 |
| Regulatory required programs | 13 | (1) | 12 |
| Transmission revenue | 10 | — | 10 |
| Other | $(12) | $ (2) | $ (14) |
| Total increase | $ 67 | $ 37 | $104 |

*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 revenue 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 revenue per customer, by customer class, regardless of changes in consumption levels. This allows BGE to recognize revenue at MDPSC-approved levels per customer, regardless of what BGE's actual distribution volumes were for a billing period.

Therefore, while this revenue is 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, 2014 compared to the same period in 2013 and normal weather consisted of the following:

| | Twelve Months Ended December 31, | | | % Change | |
|---|---|---|---|---|---|
| **Heating and Cooling Degree-Days** | **2014** | **2013** | **Normal** | **From 2013** | **From Normal** |
| Heating Degree-Days | 5,091 | 4,744 | 4,662 | 7.3% | 9.2% |
| Cooling Degree-Days | 732 | 869 | 876 | (15.8)% | (16.4)% |

*Distribution Rate Increases.*

The increase in Operating revenue net of purchased power and fuel expense was primarily due to MDPSC rate orders effective December 13, 2013 and December 15, 2014 approving increases to electric and natural gas distribution rates charged to customers. See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

*Commodity Margin.*

The increase in Revenue net of purchased power and fuel expense as a result of commodity margin for the year ended December 31, 2014 compared to the same period in 2013 was primarily due the higher gas margins earned due to extreme cold weather during the first quarter of 2014 under BGE's market-based rate incentive mechanism. See Note 12—Derivative Financial Instruments of the Combined Notes to the Consolidated Financial Statements for further information.

*Regulatory Required Programs.*

This represents the change in revenue 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 electric revenue during the year ended December 31, 2014 compared to the same period in 2013 was due to the recovery of higher energy efficiency program costs.

*Transmission.*

The increase in transmission revenue rates for the year ended December 31, 2014 compared to the same period in 2013 was primarily due to the impact of new transmission rates charged to customers that became effective in June 2014. See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

*Other.*

Other revenue decreased during the year ended December 31, 2014 compared to the same period in 2013. Other revenue, which can vary from period to period, includes miscellaneous revenue such as service application and late payment fees.

The changes in BGE's Revenue 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 | $ 82 | $31 | $113 |
| Distribution rate increases | 69 | 24 | 93 |
| Regulatory required programs | 36 | 6 | 42 |
| Other | 26 | 4 | 30 |
| Total increase | $213 | $65 | $278 |

The changes in heating and cooling degree days for the twelve months ended 2013 and 2012, consisted of the following:

| Heating and Cooling Degree-Days (a) | Twelve Months Ended December 31, 2013 | 2012 | Normal | % Change From 2012 | 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 Revenue 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.

*Distribution Rate Increases.*

The increase in Revenue net of purchased power and fuel expense as a result of distribution rate increases for the year ended December 31, 2013 compared to the same period in 2012 was primarily due to MDPSC rate orders effective February 23, 2013 and December 13, 2013 approving increases to electric and natural gas distribution rates charged to customers. 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 revenue 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 revenue during the year ended December 31, 2013 compared to the same period in 2012 was due to the recovery of higher energy efficiency programs costs.

*Other.*

Other revenue increased during the year ended December 31, 2013 compared to the same period in 2012. Other revenue, which can vary from period to period, includes miscellaneous revenue such as service application and late payment fees.

***Operating and Maintenance Expense***

The changes in operating and maintenance expense for 2014 compared to 2013 and 2013 compared to 2012 consisted of the following:

| | Increase (Decrease) 2014 vs. 2013 | Increase (Decrease) 2013 vs. 2012 |
|---|---|---|
| Baseline | | |
| Labor, other benefits, contracting and materials | $ 22 | $ 20 |
| Pension and non-pension postretirement benefits expense | 8 | — |
| Storm-related costs (a) | 21 | (62) |
| Uncollectible accounts expense | 17 | — |
| Merger transaction costs | 5 | (21) |
| Charitable contributions (b) | — | (28) |
| Other | 10 | (3) |
| Increase (Decrease) in operating and maintenance expense | $ 83 | $(94) |

(a) 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 were 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 were capital costs.

(b) 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.

### *Depreciation and Amortization Expense*

The changes in depreciation and amortization expense for 2014 compared to 2013 and 2013 compared to 2012 consisted of the following:

| | Increase (Decrease) 2014 vs. 2013 | Increase (Decrease) 2013 vs. 2012 |
|---|---|---|
| Depreciation expense [(a)] | $25 | $18 |
| Regulatory asset amortization | (1) | 31[(b)] |
| Other | (1) | 1 |
| Increase in depreciation and amortization expense | $23 | $50 |

(a) Depreciation expense increased due to higher plant balances year over year.
(b) Regulatory asset amortization for the year ended December 31, 2013 compared to the same period in 2012 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 2014 compared to 2013 and 2013 compared to 2012 consisted of the following:

| | Increase (Decrease) 2014 vs. 2013 | Increase (Decrease) 2013 vs. 2012 |
|---|---|---|
| Property tax | $2 | $ (2) |
| Franchise tax | 4 | 7 |
| Other | 2 | — |
| Increase in taxes other than income | $8 | $ 5 |

### *Interest Expense, Net*

*Year Ended December 31, 2014 Compared to Year Ended December 31, 2013.* The decrease in Interest expense, net for 2014 compared to 2013 was primarily due to favorable interest rates in 2014 on long-term debt balances.

*Year Ended December 31, 2013 Compared to Year Ended December 31, 2012.* The decrease in Interest expense, net in 2013 compared to 2012 was primarily due to 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.

### *Effective Income Tax Rate*

BGE's effective income tax rates for the years ended December 31, 2014, 2013 and 2012 were 39.9%, 39.0% and 63.6%, 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.

### *BGE Electric Operating Statistics and Revenue Detail*

| Retail Deliveries to customers (in GWhs) | 2014 | 2013 | % Change 2014 vs. 2013 | Weather-Normal % Change | 2012 | % Change 2013 vs. 2012 | Weather-Normal % Change |
|---|---|---|---|---|---|---|---|
| **Retail Deliveries** [(a)] | | | | | | | |
| Residential | 12,974 | 13,077 | (0.8)% | n.m. | 12,719 | 2.8% | n.m. |
| Small commercial & industrial | 3,086 | 3,035 | 1.7% | n.m. | 2,990 | 1.5% | n.m. |
| Large commercial & industrial | 14,191 | 14,339 | (1.0)% | n.m. | 14,956 | (4.1)% | n.m. |
| Public authorities & electric railroads | 311 | 317 | (1.9)% | n.m. | 329 | (3.6)% | n.m. |
| Total electric deliveries | 30,562 | 30,768 | (0.7)% | n.m. | 30,994 | (0.7)% | n.m. |

| Number of Electric Customers | As of December 31, 2014 | 2013 | 2012 |
|---|---|---|---|
| Residential | 1,125,369 | 1,120,431 | 1,116,233 |
| Small commercial & industrial | 112,972 | 112,850 | 112,994 |
| Large commercial & industrial | 11,730 | 11,652 | 11,580 |
| Public authorities & electric railroads | 290 | 292 | 319 |
| Total | 1,250,361 | 1,245,225 | 1,241,126 |

| Electric Revenue | 2014 | 2013 | % Change 2014 vs. 2013 | 2012 | % Change 2013 vs. 2012 |
|---|---|---|---|---|---|
| **Retail Sales** (a) | | | | | |
| Residential | $1,404 | $1,404 | — % | $1,274 | 10.2% |
| Small commercial & industrial | 271 | 257 | 5.4% | 248 | 3.6% |
| Large commercial & industrial | 491 | 439 | 11.8% | 393 | 11.7% |
| Public authorities & electric railroads | 32 | 31 | 3.2% | 30 | 3.3% |
| Total retail | 2,198 | 2,131 | 3.1% | 1,945 | 9.6% |
| Other revenue | 262 | 274 | (4.4)% | 238 | 15.1% |
| Total electric revenue | $2,460 | $2,405 | 2.3% | $2,183 | 10.2% |

(a) Reflects delivery revenue 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.

### *BGE Gas Operating Statistics and Revenue Detail*

| Deliveries to customers (in mmcf) | 2014 | 2013 | % Change 2014 vs. 2013 | Weather-Normal % Change | 2012 | % Change 2013 vs. 2012 | Weather-Normal % Change |
|---|---|---|---|---|---|---|---|
| **Retail Deliveries** (d) | | | | | | | |
| Retail sales | 99,194 | 94,020 | 5.5% | n.m. | 86,946 | 8.1% | n.m. |
| Transportation and other (e) | 9,242 | 12,210 | (24.3)% | n.m. | 15,751 | (22.5)% | n.m. |
| **Total gas deliveries** | 108,436 | 106,230 | 2.1% | n.m. | 102,697 | 3.4% | n.m. |

| Number of Gas Customers | As of December 31, 2014 | 2013 | 2012 |
|---|---|---|---|
| Residential | 609,626 | 611,532 | 610,827 |
| Commercial & industrial | 44,200 | 44,162 | 44,228 |
| Total | 653,826 | 655,694 | 655,055 |

| Gas revenue | 2014 | 2013 | % Change 2014 vs. 2013 | 2012 | % Change 2013 vs. 2012 |
|---|---|---|---|---|---|
| **Retail Sales** (d) | | | | | |
| Retail sales | $622 | $592 | 5.1% | $494 | 19.8% |
| Transportation and other (e) | 83 | 68 | 22.1% | 58 | 17.2% |
| **Total gas revenue** | $705 | $660 | 6.8% | $552 | 19.6% |

(d) Reflects delivery revenue 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 9,242 mmcfs ($72 million), 12,210 mmcfs ($55 million), and 15,751 mmcfs ($51 million) for the years ended 2014, 2013 and 2012, respectively.

**Liquidity and Capital Resources**

Exelon's and Generation's current year activity presented below includes the activity of CENG, from the integration date effective April 1, 2014 through December 31, 2014. All results included throughout the liquidity and capital resources section are presented on a GAAP basis.

The Registrants' operating and capital expenditures requirements are provided by internally generated cash flows from operations as well as funds from external sources in the capital markets and through bank borrowings. The Registrants' businesses are capital intensive and require considerable capital resources. Each 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 billion, $0.6 billion and $0.6 billion, respectively. The Registrants' revolving credit facilities are in place until 2019. In addition, Generation has $0.5 billion in bilateral facilities with banks which have various expirations between October 2015 and January 2017. 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—Debt and Credit Agreements 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—Regulatory Matters and 22—Commitments and Contingencies 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 took effect in 2013. On August 8, 2014, this funding relief was extended for five years. The estimated impacts of the law are reflected in the projected pension contributions below.

Exelon expects to make qualified pension plan contributions of $447 million to its qualified pension plans in 2015, of which Generation, ComEd, PECO and BGE expect to contribute $230 million, $138 million, $40 million and $1 million, respectively.

Exelon's and Generation's expected qualified pension plan contributions above include $36 million related to legacy CENG plans that will be funded by CENG as provided in an Employee Matters Agreement (EMA) between Exelon and CENG. Unlike the qualified pension plans, Exelon's non-qualified pension plans are not funded. Exelon expects to make non-qualified pension plan benefit payments of $15 million in 2015, of which Generation, ComEd, PECO and BGE will make payments of $6 million, $1 million, $1 million, and $1 million respectively. See Note 16—Retirement Benefits of the Combined Notes to Consolidated Financial Statements for the Registrants' 2014 and 2013 pension contributions.

To the extent interest rates decline significantly or the pension plans do not earn the expected asset return rates, annual pension contribution requirements in future years could increase, especially in years 2017 and beyond. Additionally, the contributions above could change if Exelon changes its pension funding strategy.

Unlike qualified pension plans, other postretirement benefit plans are not subject to statutory minimum contribution requirements and certain plans are not funded. Exelon's management has historically considered several factors in determining the level of contributions to its funded other postretirement benefit plans, including levels of benefit claims paid and regulatory implications (amounts deemed prudent to meet regulator expectations and best assure continued recovery). Exelon expects to make other postretirement benefit plan contributions, including benefit payments related to unfunded plans, of approximately $37 million in 2015, of which Generation, ComEd, PECO, and BGE expect to contribute $17 million, $2 million, $0 million, and $17 million, respectively. See Note 16—Retirement Benefits of the Combined Notes to Consolidated Financial Statements for the Registrants' 2014 and 2013 other postretirement benefit contributions.

See the "Contractual Obligations" section 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:

- 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 as of December 31, 2014 may be as much as $810 million, of which approximately $310 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 and interest impacts will increase by a material amount.
- Exelon, Generation, and ComEd expect to receive tax refunds of approximately $430 million, $190 million, and $260 million, respectively, in 2015. PECO expects to make tax payments of approximately $6 million related to IRS positions settling in 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.
- On December 19th, 2014, President Obama signed H.R. 5771, The Tax Increase Prevention Act. The Act included an extension of 50% bonus depreciation for 2014. As a result of the 50% bonus depreciation extension, Exelon, ExGen, ComEd, PECO, and BGE are estimated to generate incremental cash of approximately $600 million, $272 million, $217 million, $53 million, and $46 million, respectively. The resulting cash benefits are expected primarily in 2015. The cash generated is an acceleration of tax benefits that Registrants would have received over the normal depreciable life of the property. Furthermore, the extension of 50% bonus depreciation will result in a decrease to Generation's Domestic Production Activities Deduction, reducing cash tax benefits and increasing income tax expense by approximately $30 million for 2014. ComEd's 2014 revenue requirement is expected to decrease by approximately $12 million (after-tax) due to the extension of 50% bonus depreciation.

The following table provides a summary of the major items affecting Exelon's cash flows from operations for the years ended December 31, 2014, 2013 and 2012:

| | 2014 (d) | 2013 | 2014 vs. 2013 Variance | 2012 (c) | 2013 vs. 2012 Variance |
|---|---|---|---|---|---|
| Net income | $ 1,820 | $1,729 | $ 91 | 1,171 | $ 558 |
| Add (subtract): | | | | | |
| Non-cash operating activities [(a)] | 5,884 | 4,159 | 1,725 | 5,588 | (1,429) |
| Pension and non-pension postretirement benefit contributions | (617) | (422) | (195) | (462) | 40 |
| Income taxes | (143) | 883 | (1,026) | 544 | 339 |
| Changes in working capital and other noncurrent assets and liabilities [(b)] | (1,047) | (185) | (862) | (731) | 546 |
| Option premiums paid, net | 38 | (36) | 74 | (114) | 78 |
| Counterparty collateral received (paid), net | (1,478) | 215 | (1,693) | 135 | 80 |
| Net cash flows provided by operations | $ 4,457 | $6,343 | $(1,886) | $6,131 | $ 212 |

(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. See note 23 —Supplemental Financial Information for further detail on non-cash operating activity.
(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.
(c) Exelon's 2012 activity includes the activity of Constellation from the merger effective date of March 12, 2012 through December 31, 2012.
(d) On April 1, 2014, Generation assumed operational control of CENG's nuclear fleet. As a result, the 2014 activity includes CENG on a fully consolidated basis beginning April 1, 2014.

Cash flows provided by operations for the year ended December 31, 2014, 2013 and 2012 by Registrant were as follows:

| | 2014 | 2013 | 2012 |
|---|---|---|---|
| Exelon [(a)(b)] | $4,457 | $6,343 | $6,131 |
| Generation [(a)(b)] | 1,826 | 3,887 | 3,581 |
| ComEd | 1,326 | 1,218 | 1,334 |
| PECO | 712 | 747 | 878 |
| BGE [(b)] | 740 | 561 | 485 |

(a) On April 1, 2014, Generation assumed operational control of CENG's nuclear fleet. As a result, the 2014 activity includes CENG on a fully consolidated basis beginning April 1, 2014.
(b) Exelon's and Generation's 2012 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. BGE's 2012 activity includes its activity for the twelve months ended December 31, 2012.

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, except as discussed below. In addition, significant operating cash flow impacts for the Registrants for 2014, 2013 and 2012 were as follows:

*Generation*

- 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. In addition, the collateral posting and collection requirements differ depending on whether the transactions are on the exchange or in the OTC markets. During 2014, 2013 and 2012, Generation had net collections (payments) receipts of counterparty cash collateral of $(1,507) million, $162 million and $95 million, respectively. Net collections (payments) each year were primarily due to market conditions that resulted in changes to Generation's net mark-to-market position. In addition, in 2014 the exchanges increased initial margin rates, which required Generation to post higher amounts of initial margin.
- During 2014, 2013 and 2012, Generation had net collections (payments) of approximately $38 million, $(36) million and $(114) 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*

- For the year ended December 31, 2014 and 2013, ComEd had a working capital deficit of $263 million and $508 million, respectively. The working capital deficit is primarily attributable to the increase in short-term borrowings in 2014 and an increase in short-term borrowings and short-term debt due within one year in 2013. Cash flows from operating activities are sufficient to meet operating requirements; however, increased capital investment in infrastructure improvements and modernization pursuant to EIMA, transmission upgrades and expansion may require external debt financing or additional capital contributions from parent.
- During 2014, 2013 and 2012, ComEd's net payables to Generation for energy purchases related to its supplier forward contract and ICC-approved RFP contracts increased/(decreased) by $5 million, $(16) million and $(15) million, respectively. During 2014, 2013 and 2012 ComEd's payables to other energy suppliers for energy purchases increased by $27 million, $35 million and $20 million, respectively.

*PECO*

- During 2014, 2013 and 2012, PECO's payables to Generation for energy purchases increased/(decreased) by $(9) million, $(17) million and $17 million, respectively, and payables to other energy suppliers for energy purchases increased/(decreased) by $10 million, $39 million and $(22) million, respectively.

*BGE*

- During 2014, 2013 and 2012, BGE's payables to Generation for energy purchases increased/(decreased) by $13 million, $(4) million and $23 million, respectively, and payables to other energy suppliers for energy purchases increased/(decreased) by $(7) million, $(12) million and $40 million, respectively.

***Cash Flows from Investing Activities***

Cash flows used in investing activities for the year ended December 31, 2014, 2013, and 2012 by Registrant were as follows:

| | 2014 | 2013 | 2012 |
|---|---|---|---|
| Exelon [(a)(b)] | $(4,599) | $(5,394) | $(4,576) |
| Generation [(a)(b)] | (1,767) | (2,916) | (2,629) |
| ComEd | (1,655) | (1,387) | (1,212) |
| PECO | (649) | (531) | (328) |
| BGE [(b)] | (622) | (571) | (573) |

(a) On April 1, 2014, Generation assumed operational control of CENG's nuclear fleet. As a result, the 2014 activity includes CENG on a fully consolidated basis beginning April 1, 2014.
(b) Exelon's and Generation's 2012 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. BGE's 2012 activity includes its activity for the twelve months ended December 31, 2012.

*Generation*

As a result of consolidating CENG during the second quarter of 2014, Generation recorded $129 million of cash from CENG, reflected in Generation's cash flows from investing activities above. See Note 5—Investment in Constellation Energy Nuclear Group, LLC of the Combined Notes to Consolidated Financial Statements for further information.

Generation closed on the sale of its 67% equity interest in the 417 MW Safe Harbor Water Power Corporation hydroelectric facility on the Susquehanna River in Pennsylvania for a purchase price of approximately $615 million during the third quarter of 2014. The proceeds from the sale are reflected in Generation's cash flows from investing activities above. See Note 4—Mergers, Acquisitions, and Dispositions of the Combined Notes to Consolidated Financial Statements for further information.

During the third quarter of 2014, Generation established $65 million in restricted cash as part of the EGTP project financing which is reflected in Generation's cash flows from investing activities above. See Note 13—Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for more information.

Generation closed on the sale of its 41.98% and 31.28% ownership interests in the Keystone and Conemaugh coal-fired power plants and related equity interests in Keystone Fuels, LLC and Conemaugh Fuels, LLC, respectively, for a purchase price of approximately $473 million during the fourth quarter of 2014. The proceeds from the sale are reflected in Generation's cash flows from investing activities above. See Note 4—Mergers, Acquisitions, and Dispositions of the Combined Notes to Consolidated Financial Statements for further information.

During the fourth quarter of 2014, Generation closed on the sale of its fully-owned equity interest in Fore River and West Valley generating stations, for a combined purchase price of approximately $577 million. The proceeds from the sale are reflected in Generation's cash flows from investing activities above. See Note 4—Mergers, Acquisitions, and Dispositions of the Combined Notes to Consolidated Financial Statements for further information.

During the fourth quarter of 2014, Generation acquired the competitive retail electric and natural gas business activities of Integrys Energy Group, Inc. through the purchase of all of the stock of its wholly owned subsidiary, Integrys Energy Services, Inc. for a purchase price of $332 million, including net working capital. The acquisition costs from the sale are reflected in Generation's cash flows from investing activities above. See Note 4—Mergers, Acquisitions, and Dispositions of the Combined Notes to Consolidated Financial Statements for further information.

Generation has entered into several agreements to acquire equity interests in privately held and development stage entities which develop energy-related technology. The agreements include a series of scheduled investment commitments, including in-kind services contributions, totaling approximately $167 million through 2018 to fund anticipated planned capital and operating needs of the associated companies.

Generation has executed, or expects to execute, construction and services contracts to build new gas turbine units in Texas and Maryland and a new biomass-fueled cogeneration facility in Georgia. The total estimated expenditures for these projects are approximately $1.8 billion and achievement of commercial operations is expected between 2015 and 2017 for all these projects.

Capital expenditures by Registrant for the year ended December 31, 2014, 2013, and 2012 and projected amounts for 2015 are as follows:

| | Projected 2015 (a) | 2014 | 2013 | 2012 |
|---|---|---|---|---|
| Exelon (b)(e)(f) | $7,200 | $6,077 | $5,395 | $5,789 |
| Generation (b)(e)(f) | 3,625 | 3,012 | 2,752 | 3,554 |
| ComEd (c) | 2,200 | 1,689 | 1,433 | 1,246 |
| PECO | 550 | 661 | 537 | 422 |
| BGE (e) | 700 | 620 | 587 | 582 |
| Other (d) | 125 | 95 | 86 | (15) |

(a) Total projected capital expenditures do not include adjustments for non-cash activity.
(b) Includes nuclear fuel.
(c) The projected capital expenditures include $617 million of expected incremental spending 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.
(d) Other primarily consists of corporate operations and BSC.
(e) Exelon's and Generation's 2012 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. BGE's 2012 activity includes its activity for the twelve months ended December 31, 2012.
(f) On April 1, 2014, Generation assumed operational control of CENG's nuclear fleet. As a result, CENG is included on a fully consolidated basis beginning April 1, 2014.

Projected capital expenditures and other investments are subject to periodic review and revision to reflect changes in economic conditions and other factors.

In 2014, Exelon and its affiliates initiated a comprehensive project to ensure corporate-wide compliance with Version 5 of the North American Electric Reliability Corporation (NERC) Critical Infrastructure Protection Standards (CIP V.5) which will become effective on April 1, 2016. Generation, ComEd, PECO and BGE will be incurring incremental capital expenditures in 2014 through 2016 associated with the CIP V.5 compliance implementation project, which are included in projected capital expenditures above.

*Generation*

Approximately 33% and 7% of the projected 2015 capital expenditures at Generation are for the acquisition of nuclear fuel and investments in renewable energy and natural gas generation, respectively, with the remaining amounts reflecting additions and upgrades to existing facilities (including material condition improvements during nuclear refueling outages). Generation anticipates that they will fund capital expenditures with internally generated funds and borrowings.

*ComEd, PECO and BGE*

Approximately 85%, 95% and 96% 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's and BGE's capital expenditures include investments related to their respective smart meter programs. 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 that recommends ComEd, PECO, and BGE, perform assessments of their transmission lines. In compliance with this guidance, ComEd, PECO and BGE submitted their final bi-annual reports to NERC in January 2014. ComEd, PECO and BGE will be incurring 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 2015 capital expenditures above reflect capital spending for remediation to be completed in 2017.

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 the year ended December 31, 2014, 2013, and 2012 by Registrant were as follows:

| | 2014 | 2013 | 2012 |
|---|---|---|---|
| Exelon [a][b] | 411 | (826) | (1,085) |
| Generation [a][b] | (537) | (384) | (777) |
| ComEd | 359 | 61 | (212) |
| PECO | (250) | (361) | (382) |
| BGE [b] | (85) | (48) | 128 |

(a) On April 1, 2014, Generation assumed operational control of CENG's nuclear fleet. As a result, the 2014 activity includes CENG on a fully consolidated basis beginning April 1, 2014.

(b) Exelon's and Generation's 2012 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. BGE's 2012 activity includes its activity for the twelve months ended December 31, 2012.

***Debt.***

See Note 13—Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for further details of the Registrants' debt issuances and retirements. Debt activity for 2014, 2013 and 2012 by Registrant was as follows:

During the year ended December 31, 2014, the following long term debt was issued:

| Company | Type | Interest Rate | Maturity | Amount | Use of Proceeds |
|---|---|---|---|---|---|
| Exelon | Junior Subordinated Notes [(a)] | 2.50% | June 1, 2024 | $1,150 | Used to finance a portion of the acquisition of PHI and for general corporate purposes |
| Generation | Nuclear Fuel Procurement Contract | 3.35% | June 30, 2018 | 38 | Used for procurement of uranium |
| Generation | ExGen Renewables I Nonrecourse Debt [(b)] | LIBOR + 4.25% | February 6, 2021 | 300 | Used for general corporate purposes |
| Generation | ExGen Texas Power Nonrecourse Debt [(b)] | LIBOR + 4.75% | September 18, 2021 | 675 | Used for general corporate purposes |
| Generation | Energy Efficiency Project Financing | 4.12% | December 31, 2015 | 12 | Funding to install energy conservation measures in Washington, DC |
| Generation | AVSR DOE Nonrecourse Debt [(b)] | 2.78 - 3.14% | January 5, 2037 | 126 | Used for Antelope Valley solar development |
| Generation | Nuclear Fuel Procurement Contract | 3.25% | June 30, 2018 | 32 | Used for procurement of uranium |
| ComEd | First Mortgage Bonds Series 115 | 2.15% | January 15, 2019 | 300 | Used to refinance maturing mortgage bonds and general corporate purposes |
| ComEd | First Mortgage Bonds Series 116 | 4.70% | January 15, 2044 | 350 | Used to refinance maturing mortgage bonds and general corporate purposes |
| ComEd | First Mortgage Bonds Series 117 | 3.10% | November 1, 2024 | 250 | Used to repay commercial paper and general corporate purposes |
| PECO | First and Refunding Mortgage Bonds | 4.15% | October 1, 2044 | 300 | Used to repay at maturity first and refunding mortgage bonds due October 1, 2014, and general corporate purposes |

(a) See Note 13—Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for discussion of the Junior Subordinated Notes and related forward equity purchase contract, which are expected to be remarketed in 2017.
(b) See Note 13—Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for discussion of nonrecourse debt.

On January 13, 2015, Generation issued $750 million in aggregate principal amount of Senior Notes. The Senior Notes carry an annual interest rate of 2.950%, payable semi-annually, commencing July 15, 2015 and due January 15, 2020. The proceeds of the Senior Notes will be used to fund the optional redemption of Exelon's $550 million, 4.550% Senior Notes due June 15, 2015, expected to occur on February 17, 2015, and for general corporate purposes. In addition to the issuance, Exelon terminated floating-to-fixed interest rate swaps that had been designated as cash flow hedges. As the original forecasted transactions were a series of future interest payments over a ten year period, a portion of the anticipated interest payments at this time are probable not to occur. As a result Exelon will reclassify $26 million of deferred losses in AOCI to Other, net in the first quarter of 2015.

During the year ended December 31, 2013, the following long term debt was issued:

| Company | Type | Interest Rate | Maturity | Amount | Use of Proceeds |
|---|---|---|---|---|---|
| Generation | CEU Upstream Nonrecourse Debt | 2.210 - 2.440% | July 22, 2016 | $ 5 | Used to fund Upstream gas activities |
| Generation | AVSR DOE Nonrecourse Debt | 2.535 - 3.353% | January 5, 2037 | 227 | Used for Antelope Valley solar development |
| Generation | Social Security Administration Project Financing | 2.93% | February 18, 2015 | 1 | Used to install conservation measures for the Social Security Administration Headquarters facility in Maryland |
| Generation | Energy Efficiency Project Financing | 4.40% | August 31, 2014 | 9 | Used for funding to install energy conservation measures in Beckley, West Virginia |
| Generation | Continental Wind Nonrecourse Debt | 6.00% | February 28, 2033 | 613 | Used for general corporate purposes |
| ComEd | First Mortgage Bonds, Series 114 | 4.60% | August 15, 2043 | 350 | Used to repay outstanding commercial paper obligations and for general corporate purposes |
| PECO | First and Refunding Mortgage Bonds due | 1.20% | October 15, 2016 | 300 | Used to pay at maturity first and refunding mortgage bonds due October 15, 2013 and other general corporate purposes |
| PECO | First and Refunding Mortgage Bonds | 4.80% | October 15, 2043 | 250 | Used to pay at maturity first and refunding mortgage bonds due October 15, 2013 and other general corporate purposes |
| BGE | Notes | 3.35% | July 1, 2023 | 300 | Used to partially refinance Notes due July 1, 2013 and for general corporate purposes |

During the year ended December 31, 2012, the following long term debt was issued:

| Company | Type | Interest Rate | Maturity | Amount | Use of Proceeds |
|---|---|---|---|---|---|
| Generation | CEU Upstream Nonrecourse Debt | Variable Rate | July 16, 2016 | $ 78 | Used to fund Upstream gas activities |
| Generation | AVSR DOE Nonrecourse Debt | Fixed Rate | January 5, 2037 | 220 | Used for Antelope Valley solar development |
| Generation | Senior Notes | 4.25% | June 15, 2022 | 523 | Used for general corporate purposes and issued in connection with the Exchange Offer |
| Generation | Senior Notes | 5.60% | June 15, 2042 | 788 | Used for general corporate purposes and issued in connection with the Exchange Offer |
| Generation | Constellation Solar Horizons Nonrecourse Debt | 2.50% | June 7, 2030 | 38 | Used for funding for Maryland solar development |
| ComEd | First Mortgage Bonds, Series 113 | 3.80% | October 1, 2042 | 350 | Used to repay outstanding commercial paper obligations and for general corporate purposes |
| PECO | First and Refunding Mortgage Bonds | 2.38% | September 15, 2022 | 350 | Used to pay at maturity First Mortgage Bonds due October 1, 2012 and for general corporate purposes |
| BGE | Notes | 2.80% | August 15, 2022 | 250 | Used to repay total outstanding commercial paper obligations and for general corporate purposes |

During the year ended December 31, 2014, the following long term debt was retired and/or redeemed:

| Company | Type | Interest Rate | Maturity | Amount |
|---|---|---|---|---|
| Generation | 2003 Senior Notes | 5.35% | January 15, 2014 | $500 |
| Generation | Pollution Control Loan | 4.10% | July 1, 2014 | 20 |
| Generation | Continental Wind Nonrecourse Debt [(a)] | 6.00% | February 28, 2033 | 20 |
| Generation | Kennett Square Capital Lease | 7.83% | September 20, 2020 | 3 |
| Generation | ExGen Renewables I Nonrecourse Debt [(a)] | LIBOR + 4.25% | February 6, 2021 | 18 |
| Generation | ExGen Texas Power Nonrecourse Debt [(a)] | LIBOR + 4.75% | September 18, 2021 | 2 |
| Generation | AVSR DOE Nonrecourse Debt [(a)] | 2.33% - 3.55% | January 5, 2037 | 15 |
| Generation | Constellation Solar Horizons Nonrecourse Debt [(a)] | 2.56% | September 7, 2030 | 2 |
| Generation | Sacramento PV Energy Nonrecourse Debt [(a)] | 2.56% | December 31, 2030 | 2 |
| Generation | Energy Efficiency Project Financing | 4.12% | December 31, 2015 | 12 |
| ComEd | Mortgage Bonds Series 110 | 1.63% | January 15, 2014 | 600 |
| ComEd | Pollution Control Series 1994C | 5.85% | January 15, 2014 | 17 |
| PECO | First and Refunding Mortgage Bonds | 5.00% | October 1, 2014 | 250 |
| BGE | Rate Stabilization Bonds | 5.72% | April 1, 2017 | 35 |
| BGE | Rate Stabilization Bonds | 5.72% | October 1, 2014 | 35 |

(a) See Note 13—Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for discussion of nonrecourse debt.

During the year ended December 31, 2013, the following long term debt was retired and/or redeemed:

| Company | Type | Interest Rate | Maturity | Amount |
|---|---|---|---|---|
| Generation | Kennett Square Capital Lease | 7.83% | September 1, 2020 | $ 3 |
| Generation | Solar Revolver Nonrecourse Debt | Variable Rate | July 7, 2014 | 113 |
| Generation | Constellation Solar Horizons Nonrecourse Debt | 2.56% | September 7, 2030 | 2 |
| Generation | Sacramento Energy Nonrecourse Debt | 2.68% | December 31, 2030 | 2 |
| Generation [(a)] | Series A Junior Subordinated Debentures | 8.63% | June 15, 2063 | 450 |
| Generation | Energy Efficiency Project Financing | 4.40% | August 31, 2014 | 9 |
| ComEd | First Mortgage Bonds, Series 92 | 7.63% | April 15, 2013 | 125 |
| ComEd | First Mortgage Bonds, Series 94 | 7.50% | July 1, 2013 | 127 |
| PECO | First and Refunding Mortgage Bonds | 5.60% | October 15, 2013 | 300 |
| BGE | Rate Stabilization Bonds | 5.72% | April 1, 2017 | 67 |
| BGE | Notes | 6.13% | July 1, 2013 | 400 |

(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.

During the year ended December 31, 2012, the following long term debt was retired and/or redeemed:

| Company | Type | Interest Rate | Maturity | Amount |
|---|---|---|---|---|
| Exelon | Fixed rate Medium Term Notes | 7.30% | June 1, 2012 | $ 2 |
| Exelon | Fixed rate Senior Notes | 7.60% | April 1, 2032 | 442 |
| Generation | Kennett Square Capital Lease | 7.83% | September 20, 2020 | 2 |
| Generation | 3-year term rate Armstrong Co. 2009 A, Pollution Control Notes | 5.00% | December 1, 2042 | 46 |
| Generation | CEU Upstream Nonrecourse Debt | Variable Rate | July 16, 2016 | 89 |
| Generation | Solar Revolver Nonrecourse Debt | Variable Rate | July 7, 2014 | 17 |
| Generation | MEDCO Tax-Exempt Bonds | Variable Rate | April 1, 2024 | 75 |
| Generation | Sacramento PV Energy Nonrecourse Debt | Variable Rate | March 12, 2012 | 2 |
| ComEd | First Mortgage Bonds, Series 98 | 6.15% | March 15, 2012 | 450 |
| PECO | First and Refunding Mortgage Bonds | 4.75% | October 1, 2012 | 225 |
| PECO | First and Refunding Mortgage Bonds | 4.00% | December 1, 2012 | 150 |
| BGE | Rate Stabilization Bonds | 5.72% | April 1, 2016 | 8 |
| BGE | Rate Stabilization Bonds | 5.47% | October 1, 2012 | 55 |
| BGE | Medium Term Notes | Variable Rate | June 15, 2012 | 110 |

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 for the year ended December 31, 2014, 2013 and 2012 by Registrant were as follows:

| | 2014 | 2013 | 2012 |
|---|---|---|---|
| Exelon (a) | $1,486 | $1,249 | 1,716 |
| Generation (a) | 1,066 | 625 | 1,626 |
| ComEd | 307 | 220 | 105 |
| PECO | 320 | 333 | 347 |
| BGE (b) | 13 | 13 | 13 |

(a) On April 1, 2014, Generation assumed operational control of CENG's nuclear fleet. As a result, the 2014 activity includes CENG on a fully consolidated basis beginning April 1, 2014. As such, includes $421 million of distributions to EDF in 2014.

(b) Relates to dividends paid on BGE's preference 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.

***Second Quarter 2014 Dividend***

On May 6, 2014, the Exelon Board of Directors declared a second quarter 2014 regular quarterly dividend of $0.31 per share on Exelon's common stock payable on June 10, 2014, to shareholders of record of Exelon at the end of the day on May 16, 2014.

***Third Quarter 2014 Dividend***

On July 29, 2014, the Exelon Board of Directors declared a third quarter 2014 regular quarterly dividend of $0.31 per share on Exelon's common stock payable on September 10, 2014 to shareholders of record of Exelon at the end of the day on August 15, 2014.

***Fourth Quarter 2014 Dividend***

On October 21, 2014, the Exelon Board of Directors declared a fourth quarter 2014 regular quarterly dividend of $0.31 per share on Exelon's common stock payable on December 10, 2014 to shareholders of record of Exelon at the end of the day on November 14, 2014.

***First Quarter 2015 Dividend***

On January 27, 2015, the Exelon Board of Directors declared a first quarter 2015 regular quarterly dividend of $0.31 per share on Exelon's common stock payable on March 10, 2015, to shareholders of record of Exelon at the end of the day on February 13, 2015.

***Short-Term Borrowings.*** Short-term borrowings incurred (repaid) during 2014, 2013 and 2012 by Registrant were as follows:

| | 2014 | 2013 | 2012 |
|---|---|---|---|
| Generation [(a)] | $ 17 | $ 13 | $ (52) |
| ComEd | 120 | 184 | — |
| BGE | (15) | 135 | — |
| Other [(b)] | — | — | (145) |
| Exelon [(a)] | $122 | $332 | $(197) |

(a) On April 1, 2014, Generation assumed operational control of CENG's nuclear fleet. As a result, the 2014 activity includes CENG on a fully consolidated basis beginning April 1, 2014.
(b) 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 2014, 2013 and 2012 by the Registrants.

***Contributions from ParentlMember.*** Contributions from Parent/Member (Exelon) during 2014, 2013 and 2012 by Registrant were as follows:

| | 2014 | 2013 | 2012 |
|---|---|---|---|
| Generation | $ 53 | $ 26 | $48 |
| ComEd [(a)] | 278 | 176 | 11 |
| PECO | 24 | 27 | 9 |
| BGE | — | — | 66 |

(a) In 2014 and 2013, represents indemnification from Exelon in relation to the like-kind exchange transaction. For 2014 , also represents contributions from Exelon to support expanded capital programs.

***Distributions to Noncontrolling Interests of Consolidated VIE.*** On April 1, 2014, Generation loaned $400 million to CENG, the proceeds of which were used to make a distribution to EDFI of $400 million. See Note 5—Investment in Constellation Energy Nuclear Group, LLC of the Combined Notes to Consolidated Financial Statements for additional information on the integration of CENG.

***Other.*** For the year ended December 31, 2014, other financing activities primarily consisted of financing costs associated with the acquisition of PHI, other project financing and various debt issuance costs. See notes 4, 13, and 19 of the Combined Notes to Consolidated Financial Statements' for additional information.

***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 $8.5 billion in aggregate total commitments of which $7.3 billion was available as of December 31, 2014, 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 2014 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.

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, 2014, it would have been required to provide incremental collateral of $2.4 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 $4.6 billion. If ComEd lost its investment grade credit ratings as of December 31, 2014, it would have been required to provide incremental collateral of $14 million, which is well within its current available credit facility capacity of $998 million. If PECO lost its investment grade credit rating as of December 31, 2014 it would not be required to provide collateral pursuant to PJM's credit policy and could have been required to provide collateral of $36 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, 2014 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 $79 million related to its natural gas procurement contracts, which, in the aggregate, are well within BGE's current available credit facility capacity of $600 million.

*Exelon Credit Facilities*

See Note 13—Debt and Credit Agreements 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, 2014, the capital structures of the Registrants consisted of the following:

| | Exelon | Generation | ComEd | PECO | BGE |
|---|---|---|---|---|---|
| Long-term debt | 46% | 30% | 42% | 41% | 36% |
| Long-term debt to affiliates [(a)] | 1% | 7% | 1% | 3% | 5% |
| Common equity | 52% | — | 55% | 56% | 53% |
| Member's equity | — | 63% | — | — | — |
| Preference Stock | — | — | — | — | 4% |
| Commercial paper and notes payable | 1% | — | 2% | — | 2% |

(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—Variable Interest Entities 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, 2014, in addition to the net contribution or borrowing as of December 31, 2014, are presented in the following table:

| | Maximum Contributed | Maximum Borrowed | December 31, 2014 Contributed (Borrowed) |
|---|---|---|---|
| Generation | $ 84 | $573 | $ — |
| PECO | 129 | 35 | — |
| BSC | 15 | 360 | (261) |
| Exelon Corporate | 780 | N/A | 261 |

***Investments in Nuclear Decommissioning Trust Funds.*** Exelon, Generation and CENG maintain trust funds, as required by the NRC, to fund certain costs of decommissioning 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 and CENG's investment policies 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. As of December 31, 2014, ComEd had $702 million available in long-term debt refinancing authority and $943 million available in new money long-term debt financing authority from the ICC. During the fourth quarter of 2014, ComEd requested an extension of the expiration date of the refinancing authority from the ICC. In January 2015, the ICC approved the extension of the refinancing authority, which now expires on February 27, 2017. As of December 31, 2014, PECO had $1.1 billion available in long-term debt financing authority from the PAPUC. As of December 31, 2014, BGE had $1.4 billion 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, 2014, 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—Regulatory Matters 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, 2014, Exelon had retained earnings of $10,910 million, including Generation's undistributed earnings of $3,803 million, ComEd's retained earnings of $851 million consisting of retained earnings appropriated for future dividends of $2,490 million partially offset by $1,639 million of unappropriated retained deficit, PECO's retained earnings of $681 million and BGE's retained earnings $1,203 million. See Note 22—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information regarding fund transfer restrictions.

**Contractual Obligations**

The following table summarizes Exelon's future estimated cash payments as of December 31, 2014 under existing contractual obligations, including payments due by period. See Note 22—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for information regarding the Registrants' commercial and other commitments, representing commitments potentially triggered by future events.

| | | Payment due within | | | | |
|---|---|---|---|---|---|---|
| | Total | 2015 | 2016-2017 | 2018-2019 | Due 2020 and beyond | All Other |
| Long-term debt [(a)] | $21,372 | $1,736 | $ 3,661 | $2,387 | $13,588 | $— |
| Interest payments on long-term debt [(b)] | 13,105 | 922 | 1,755 | 1,435 | 8,993 | — |
| Liability and interest for uncertain tax positions [(c)] | 779 | — | — | — | — | 779 |
| Capital leases | 32 | 3 | 8 | 9 | 12 | — |
| Operating leases [(d)] | 1,158 | 99 | 204 | 156 | 699 | — |
| Purchase power obligations [(e)] | 2,084 | 590 | 884 | 295 | 315 | — |
| Fuel purchase agreements [(f)] | 10,020 | 1,661 | 2,555 | 2,048 | 3,756 | — |
| Electric supply procurement [(f)] | 1,510 | 1,057 | 453 | — | — | — |
| AEC purchase commitments [(f)] | 8 | 1 | 2 | 2 | 3 | — |
| Curtailment services commitments [(f)] | 115 | 40 | 63 | 12 | — | — |
| Long-term renewable energy and REC commitments [(g)] | 1,516 | 75 | 152 | 162 | 1,127 | — |
| Other purchase obligations [(h)] | 894 | 336 | 408 | 66 | 84 | — |
| Construction commitments [(i)] | 1,143 | 43 | 1,100 | — | — | — |
| PJM regional transmission expansion commitments [(j)] | 786 | 259 | 414 | 113 | — | — |
| Spent nuclear fuel obligation [(k)] | 1,021 | — | — | — | 1,021 | — |
| Pension minimum funding requirement [(l)] | 1,892 | 447 | 782 | 424 | 239 | — |
| Total contractual obligations | $57,435 | $7,269 | $12,441 | $7,109 | $29,837 | $779 |

(a) Includes $648 million due after 2020 to ComEd, PECO and BGE financing trusts.

(b) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2014 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, 2014. Includes estimated interest payments due to ComEd, PECO and BGE financing trusts.

(c) As of December 31, 2014, Exelon's liability for uncertain tax positions and related interest payable was $469 million and $310 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—Income Taxes 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, 2014, 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—Regulatory Matters and 22—Commitments and Contingencies 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—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for electric and gas purchase commitments.

(g) Primarily related to ComEd 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 commitments represent the maximum settlements with suppliers for renewable energy and RECs under the existing contract terms. See Note 3—Regulatory Matters of Combined Notes to Consolidated Financial Statements for additional information.

(h) Represents commitments for services, materials, information technology, smart meter installation and commitments related to assets-held-for-sale. See Note 22—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information.

(i) Represents commitments for Generation's ongoing investments in renewables development, new natural gas and biomass generation construction. See Note 22—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements.

(j) 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—Regulatory Matters of Combined Notes to Consolidated Financial Statements for additional information.

(k) See Note 22—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for further information regarding spent nuclear fuel obligations.

(l) These amounts represent Exelon's expected contributions to its qualified pension plans. For Exelon's largest qualified pension plan, the projected contributions reflect a funding strategy of contributing the greater of $250 million until the plan is fully funded on an accumulated benefit obligation basis, and the minimum amounts under ERISA to avoid benefit restrictions and at-risk status thereafter. The remaining qualified pension plans' contributions are generally based on the estimated minimum pension contributions required under ERISA and the Pension Protection Act of 2006, as well as contributions necessary 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 2020 are not included. See Note 16—Retirement Benefits of the Combined Notes to Consolidated Financial Statements for further information regarding estimated future pension benefit payments.

See Note 22—Commitments and Contingencies 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—Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements.
- long-term debt, see Note 13—Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements.
- liabilities related to uncertain tax positions, see Note 14—Income Taxes of the Combined Notes to Consolidated Financial Statements.
- capital lease obligations, see Note 13—Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements.
- operating leases, energy commitments, fuel purchase agreements, construction commitments and rate relief commitments, see Note 22—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements.
- the nuclear decommissioning and SNF obligations, see Notes 15—Asset Retirement Obligations and 22—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements.
- regulatory commitments, see Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements.
- variable interest entities, see Note 2—Variable Interest Entities of the Combined Notes to Consolidated Financial Statements.
- nuclear insurance, see Note 22—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements.
- new accounting pronouncements, see Note 1—Significant Accounting Policies of the Combined Notes to Consolidated Financial Statements.

## 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 executive officer and includes the chief risk officer, chief strategy officer, chief executive officer of Exelon Utilities, chief commercial officer, chief financial officer and chief executive officer of Constellation. The RMC reports to the Finance and Risk Committee of the Exelon Board of Directors on the scope of the risk management activities.

### Commodity Price Risk

Commodity price risk is associated with price movements resulting from changes in supply and demand, fuel costs, market liquidity, weather conditions, governmental regulatory and environmental policies, and other factors. To the extent the 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 2015 through 2017.

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, 2014, the percentage of expected generation hedged for the major reportable segments was 93%-96%, 61%-64% and 31%-34% for 2015, 2016 and 2017, respectively. The percentage of expected generation hedged is the amount of equivalent sales divided by the expected generation (which reflects the divestiture impact of Quail Run). Expected generation is the volume of energy that best represents our commodity position in energy markets from owned or contracted for capacity based upon a simulated dispatch model that makes assumptions regarding future market conditions, which are calibrated to market quotes for power, fuel, load following products, and options. 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. See Note 4—Mergers, Acquisitions, and Dispositions of the Combined Notes to Consolidated Financial Statements for more detail regarding divestitures.

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, 2014, market conditions and hedged position would be a decrease in pre-tax net income of approximately $10 million, $350 million and $670 million, respectively, for 2015, 2016 and 2017. 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 10,571 GWh, 8,762 GWh, and 12,958 GWh for the years ended December 31, 2014, 2013 and 2012 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, 2014, resulted in pre-tax gains of $42 million due to net mark-to-market losses of $26 million and realized gains of $68 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 $0.4 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, 2014 of $7,468 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 50% of Generation's uranium concentrate requirements from 2015 through 2019 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—Commitments and Contingencies 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. In addition, the ICC's December 18, 2013 Order approved the reduction of ComEd's commitments under those contracts for the June 2014 through May 2015 procurement period, and the amount of the reduction was approved by the ICC in March 2014. See Note 3—Regulatory Matters and Note 12—Derivative Financial Instruments 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—Regulatory Matters of the Combined Notes to the Consolidated Financial Statements. PECO has certain full requirements contracts and block contracts, which are considered derivatives and 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—Derivative Financial Instruments 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—Derivative Financial Instruments 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 commodity mark-to-market net asset or liability balance sheet position from January 1, 2013 to December 31, 2014. 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—Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information on the balance sheet classification of the mark-to-market energy contract net assets (liabilities) recorded as of December 31, 2014 and December 31, 2013.

| | Generation | ComEd | Intercompany Eliminations [b] | Exelon |
|---|---|---|---|---|
| Total mark-to-market energy contract net assets (liabilities) at January 1, 2013 [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 | 25 | — | 13 | 38 |
| Reclassification to realized at settlement from accumulated OCI [c] | (683) | — | 219 | (464) |
| Changes in fair value—energy derivatives [d] | — | 100 | (226) | (126) |
| Changes in allocated collateral | (175) | — | — | (175) |
| Changes in net option premium paid/(received) | 36 | — | — | 36 |
| Option premium amortization | (104) | — | — | (104) |
| Other balance sheet reclassifications | (1) | — | — | (1) |
| Total mark-to-market energy contract net assets (liabilities) at December 31, 2013 [a] | 1,047 | $(193) | $ — | 854 |
| Contracts acquired at merger date [e] | 128 | | | 128 |
| Total change in fair value during 2014 of contracts recorded in result of operations | (608) | — | — | (608) |
| Reclassification to realized at settlement of contracts recorded in results of operations | (21) | — | — | (21) |
| Reclassification to realized at settlement from accumulated OCI | (195) | — | — | (195) |
| Changes in fair value—energy derivatives [d] | — | (14) | — | (14) |
| Changes in allocated collateral | 1,503 | — | — | 1,503 |
| Changes in net option premium paid/(received) | (38) | — | — | (38) |
| Option premium amortization | (122) | — | — | (122) |
| Other balance sheet reclassifications | 18 | — | — | 18 |
| Total mark-to-market energy contract net assets (liabilities) at December 31, 2014 [a] | $1,712 | $(207) | $ — | $1,505 |

(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 $219 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 year ended December 31, 2013.

(d) For ComEd, the changes in fair value are recorded as a change in regulatory assets or liabilities. As of December 31, 2014 and 2013, ComEd recorded a regulatory liability of $207 million and $193 million, respectively, related to its mark-to-market derivative liabilities with Generation and unaffiliated suppliers. As of December 31, 2013, this includes $11 million of decreases in fair value and $215 million 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, 2014 and 2013 ComEd also recorded $13 million and $133 million, respectively, of increases in fair value, and $1 million and $7 million, respectively, of realized losses due to settlements associated with floating-to-fixed energy swap contracts with unaffiliated suppliers.

(e) Includes $81 million of fair value from contracts acquired and $47 million of cash collateral as a result of the Integrys acquisition.

***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 | | | | | | |
|---|---|---|---|---|---|---|---|
| | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 and Beyond | Total Fair Value |
| *Normal Operations, Commodity derivative contracts* [(a)(b)]: | | | | | | | |
| Actively quoted prices (Level 1) | $ (118) | $ (5) | $ 3 | $(10) | $ (5) | $ 1 | $ (134) |
| Prices provided by external sources (Level 2) | 522 | 244 | 21 | 7 | — | 2 | 796 |
| Prices based on model or other valuation methods (Level 3) [(c)] | 625 | 217 | 140 | (21) | (21) | (97) | 843 |
| Total | $1,029 | $456 | $164 | $(24) | $(26) | $(94) | $1,505 |

(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 $1,406 million at December 31, 2014.
(c) Includes ComEd's net assets (liabilities) associated with the floating-to-fixed energy swap contracts with unaffiliated suppliers.

***Generation***

| | Maturities Within | | | | | | |
|---|---|---|---|---|---|---|---|
| | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 and Beyond | Total Fair Value |
| *Normal Operations, Commodity derivative contracts* [(a)(b)]: | | | | | | | |
| Actively quoted prices (Level 1) | $ (118) | $ (5) | $ 3 | $(10) | $ (5) | $ 1 | $ (134) |
| Prices provided by external sources (Level 2) | 522 | 244 | 21 | 7 | — | 2 | 796 |
| Prices based on model or other valuation methods (Level 3) | 645 | 236 | 157 | (4) | (4) | 20 | 1,050 |
| Total | $1,049 | $475 | $181 | $ (7) | $ (9) | $23 | $1,712 |

(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 $1,406 million at December 31, 2014.

***ComEd***

| | Maturities Within | | | | | | |
|---|---|---|---|---|---|---|---|
| | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 and Beyond | Fair Value |
| Prices based on model or other valuation methods (Level 3) [(a)] | $(20) | $(19) | $(17) | $(17) | $(17) | $(117) | $(207) |

(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**

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—Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for a detailed 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, 2014. 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 exclude credit risk exposure from individual retail customers, uranium procurement contracts and exposure through RTOs, ISOs, NYMEX, ICE, and Nodal commodity exchanges, which are discussed below. Additionally, the figures in the tables below exclude exposures with affiliates, including net receivables with ComEd, PECO and BGE of $43 million, $29 million and $40 million, respectively. See Note 25—Related Party Transactions of the Combined Notes to Consolidated Financial Statements for additional information.

| Rating as of December 31, 2014 | 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 | $1,629 | $ 62 | $1,567 | 1 | $452 |
| Non-investment grade | 49 | 19 | 30 | — | — |
| No external ratings | | | | | |
| Internally rated—investment grade | 479 | — | 479 | — | — |
| Internally rated—non-investment grade | 60 | 4 | 56 | — | — |
| Total | $2,217 | $ 85 | $2,132 | 1 | $452 |

| | Maturity of Credit Risk Exposure | | | |
|---|---|---|---|---|
| Rating as of December 31, 2014 | Less than 2 Years | 2-5 Years | Exposure Greater than 5 Years | Total Exposure Before Credit Collateral |
| Investment grade | $1,196 | $379 | $ 54 | $1,629 |
| Non-investment grade | 35 | 11 | 3 | 49 |
| No external ratings | | | | |
| Internally rated—investment grade | 388 | 90 | 1 | 479 |
| Internally rated—non-investment grade | 60 | — | — | 60 |
| Total | $1,679 | $480 | $ 58 | $2,217 |

| Net Credit Exposure by Type of Counterparty | As of December 31, 2014 |
|---|---|
| Financial institutions | $ 295 |
| Investor-owned utilities, marketers, power producers | 958 |
| Energy cooperatives and municipalities | 862 |
| Other | 17 |
| Total | $2,132 |

(a) As of December 31, 2014, credit collateral held from counterparties where Generation had credit exposure included $69 million of cash and $16 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—Significant Accounting Policies 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, 2014. See Note 3—Regulatory Matters 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, 2014, 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—Significant Accounting Policies 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, 2014.

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, 2014, 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, 2014, PECO had credit exposure of $8 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—Significant Accounting Policies 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 Public Utilities Article of the Annotated Code of Maryland 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, 2014.

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, 2014, 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, 2014, BGE had credit exposure of $8 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***

***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—Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for information regarding collateral requirements.

Generation transacts 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 or fall below contracted price levels, Generation or its counterparties may be required to post collateral with one another. 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—Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information.

As of December 31, 2014, Generation had cash collateral of $1,497 million posted and cash collateral held of $77 million for counterparties with derivative positions, of which $1,406 million and $6 million in net cash collateral deposits were offset against energy mark-to-market and interest rate and foreign exchange derivative assets and liabilities related to underlying energy contracts, respectively. As of December 31, 2014, $8 million of cash collateral posted was not offset against net derivative positions because it was not associated with energy-related derivatives or as of the balance sheet date there were no positions to offset. As of December 31, 2013, Generation had cash collateral posted of $72 million 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 mark-to-market assets and liabilities because it was not associated with energy-related derivatives or at the balance sheet date there were no positions to offset. See Note 22—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for information regarding the letters of credit supporting the cash collateral.

***ComEd***

As of December 31, 2014, ComEd held approximately $2 million 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 Note 3—Regulatory Matters and Note 12—Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information.

***PECO***

As of December 31, 2014, PECO was not required to post collateral under its energy and natural gas procurement contracts. See Note 12—Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information.

***BGE***

BGE is not required to post collateral under its electric supply contracts. As of December 31, 2014, 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—Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information.

***RTOs and ISOs***

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***

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. In 2014 the exchanges increased initial margin rates, which required Generation to post higher amounts of initial margin collateral. Generation believes that increased market volatility and extreme weather events, such as the Polar Vortex, contributed to the rate increases.

***Long-Term Leases***

Exelon's Consolidated Balance Sheet, as of December 31, 2014, included a $361 million net investment in coal-fired plants in Georgia subject to long-term leases. This investment represents the estimated residual value of leased assets at the end of the respective lease terms of $685 million, less unearned income of $324 million. The lease agreements provide the lessees with fixed purchase options at the end of the lease terms. If the lessee does not exercise the fixed purchase options, Exelon has the ability to operate the stations and keep or market the power itself or require the lessee to arrange for a third-party to bid on a service contract for a period following the lease term. Exelon will be subject to residual value risk if the lessee does 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.

Exelon's Consolidated Balance Sheet, as of December 31, 2013, also included a net investment in a coal-fired plant in Texas subject to a long-term lease. In February 2014, Exelon and the City Public Service Board of San Antonio, Texas (CPS) finalized an agreement to terminate the leases prior to their expiration dates. As a result of the lease termination, Exelon received a net early termination amount of $335 million from CPS and wrote off the net investment in the CPS long-term lease of $336 million; resulting in a pre-tax loss of $1 million. See Note 14—Income Taxes of the Combined Notes to Consolidated Financial Statements for the impact of the lease termination on income taxes.

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 annual reviews performed in 2014 and 2013, the estimated residual value of Exelon's direct financing leases for the Georgia generating stations experienced other than temporary declines given reduced long-term energy and capacity price expectations. As a result, Exelon recorded a $24 million and $14 million pre-tax impairment charge in 2014 and 2013, respectively, for these stations. See Note 8—Impairment of Long-Lived Assets of the Combined Notes to Consolidated Financial Statements for further information.

**Interest Rate and Foreign Exchange Risk**

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, 2014, Exelon and Generation had $1,450 million and $550 million of notional amounts of fixed-to-floating hedges outstanding, respectively, and $3,070 million and $770 million of notional amounts of floating-to-fixed hedges outstanding, respectively. 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 approximately a $8 million decrease in Exelon Consolidated pre-tax income for the year ended December 31, 2014. 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.

**Equity Price Risk**

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, 2014, 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 $617 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 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.

## CERTIFICATIONS

The CEO of Exelon has made the required annual certifications for 2014 to the New York Stock Exchange in compliance with the New York Stock Exchange listing standards. The CEO and CFO have filed with the SEC all required certifications under section 302 of the Sarbanes-Oxley Act of 2002. These certifications are filed as exhibits 31-1 and 31-2 to Exelon's 2014 Form 10-K.

## 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, 2014. In making this assessment, management used the criteria in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, Exelon's management concluded that, as of December 31, 2014, Exelon's internal control over financial reporting was effective.

We excluded Integrys, which we acquired on November 1, 2014, from management's assessment of the effectiveness of Exelon's internal control over financial reporting as of December 31, 2014. This exclusion is in accordance with the SEC's general guidance that an assessment of a recently acquired business may be omitted from our scope in the year of acquisition.

The effectiveness of the Exelon's internal control over financial reporting as of December 31, 2014, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

February 13, 2015

**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, 2014 and 2013 and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2014 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) 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, 2014, based on criteria established in *Internal Control—Integrated Framework (2013)* 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 Management's Report on Internal Control over Financial Reporting appearing under Item 8. 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.

As described in Management's Report on Internal Control over Financial Reporting appearing under Item 8, management has excluded Integrys Energy Services, Inc. ("Integrys") from its assessment of internal control over financial reporting as of December 31, 2014 because it was acquired by the Company in a purchase business combination on November 1, 2014. We have also excluded Integrys from our audit of internal control over financial reporting. Integrys is a wholly-owned subsidiary whose total assets and total revenues represent 0.74% and 1.41%, respectively, of the related consolidated financial statement amounts as of and for the year ended December 31, 2014.

/s/ PricewaterhouseCoopers LLP
Chicago, Illinois
February 13, 2015

**Exelon Corporation and Subsidiary Companies**

**Consolidated Statements of Operations and Comprehensive Income**

| (In millions, except per share data) | For the Years Ended December 31, 2014 | 2013 | 2012 |
|---|---|---|---|
| **Operating revenues** | $27,429 | $24,888 | $23,489 |
| **Operating expenses** | | | |
| Purchased power and fuel | 12,472 | 9,468 | 9,121 |
| Purchased power and fuel from affiliates | 531 | 1,256 | 1,036 |
| Operating and maintenance | 8,568 | 7,270 | 7,961 |
| Depreciation and amortization | 2,314 | 2,153 | 1,881 |
| Taxes other than income | 1,154 | 1,095 | 1,019 |
| Total operating expenses | 25,039 | 21,242 | 21,018 |
| **Equity in (losses) earnings of unconsolidated affiliates** | (20) | 10 | (91) |
| **Gain (loss) on sales of assets** | 437 | 13 | (7) |
| **Gain on consolidation and acquisition of businesses** | 289 | — | — |
| **Operating income** | 3,096 | 3,669 | 2,373 |
| **Other income and (deductions)** | | | |
| Interest expense, net | (1,024) | (1,315) | (891) |
| Interest expense to affiliates, net | (41) | (41) | (37) |
| Other, net | 455 | 460 | 353 |
| Total other income and (deductions) | (610) | (896) | (575) |
| **Income before income taxes** | 2,486 | 2,773 | 1,798 |
| **Income taxes** | 666 | 1,044 | 627 |
| **Net income** | 1,820 | 1,729 | 1,171 |
| **Net income attributable to noncontrolling interest, preferred security dividends and preference stock dividends** | 197 | 10 | 11 |
| **Net income attributable to common shareholders** | 1,623 | 1,719 | 1,160 |
| **Comprehensive income (loss), net of income taxes** | | | |
| Net income | 1,820 | 1,729 | 1,171 |
| **Other comprehensive income (loss), net of income taxes** | | | |
| Pension and non-pension postretirement benefit plans: | | | |
| Prior service (benefit) cost reclassified to periodic benefit cost | (30) | — | 1 |
| Actuarial loss reclassified to periodic cost | 147 | 208 | 168 |
| Transition obligation reclassified to periodic cost | — | — | 2 |
| Pension and non-pension postretirement benefit plan valuation adjustment | (497) | 669 | (371) |
| Unrealized loss on cash flow hedges | (148) | (248) | (120) |
| Unrealized gain on marketable securities | 1 | 2 | 2 |
| Unrealized gain on equity investments | 8 | 106 | 1 |
| Unrealized loss on foreign currency translation | (9) | (10) | — |
| Reversal of CENG equity method AOCI | (116) | — | — |
| Other comprehensive (loss) income | (644) | 727 | (317) |
| **Comprehensive income** | $ 1,176 | $ 2,456 | $ 854 |
| **Average shares of common stock outstanding:** | | | |
| Basic | 860 | 856 | 816 |
| Diluted | 864 | 860 | 819 |
| **Earnings per average common share:** | | | |
| Basic | $ 1.89 | $ 2.01 | $ 1.42 |
| Diluted | $ 1.88 | $ 2.00 | $ 1.42 |
| **Dividends per common share** | $ 1.24 | $ 1.46 | $ 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, 2014 | 2013 | 2012 |
|---|---|---|---|
| **Cash flows from operating activities** | | | |
| Net income | $ 1,820 | $ 1,729 | $ 1,171 |
| 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 | 3,868 | 3,779 | 4,079 |
| Impairment of long-lived assets | 687 | 171 | 284 |
| Gain on consolidation and acquisition of businesses | (296) | — | — |
| (Gain) loss on sales of assets | (437) | (13) | 7 |
| Deferred income taxes and amortization of investment tax credits | 502 | 119 | 615 |
| Net fair value changes related to derivatives | 716 | (445) | (604) |
| Net realized and unrealized gains on nuclear decommissioning trust fund investments | (210) | (170) | (157) |
| Other non-cash operating activities | 1,054 | 718 | 1,364 |
| Changes in assets and liabilities: | | | |
| Accounts receivable | (318) | (97) | 243 |
| Inventories | (380) | (100) | 26 |
| Accounts payable, accrued expenses and other current liabilities | 209 | (90) | (632) |
| Option premiums received (paid), net | 38 | (36) | (114) |
| Counterparty collateral (posted) received, net | (1,478) | 215 | 135 |
| Income taxes | (143) | 883 | 544 |
| Pension and non-pension postretirement benefit contributions | (617) | (422) | (462) |
| Other assets and liabilities | (558) | 102 | (368) |
| Net cash flows provided by operating activities | 4,457 | 6,343 | 6,131 |
| **Cash flows from investing activities** | | | |
| Capital expenditures | (6,077) | (5,395) | (5,789) |
| Proceeds from termination of direct financing lease investment | 335 | — | — |
| Proceeds from nuclear decommissioning trust fund sales | 7,396 | 4,217 | 7,265 |
| Investment in nuclear decommissioning trust funds | (7,551) | (4,450) | (7,483) |
| Cash and restricted cash acquired from consolidations and acquisitions | 140 | — | 964 |
| Acquisitions of businesses | (386) | — | (21) |
| Proceeds from sales of long-lived assets | 1,719 | 32 | 371 |
| Proceeds from sales of investments | 7 | 22 | 28 |
| Purchases of investments | (3) | (4) | (13) |
| Change in restricted cash | (104) | (43) | (34) |
| Distribution from CENG | 13 | 115 | — |
| Other investing activities | (88) | 112 | 136 |
| Net cash flows used in investing activities | (4,599) | (5,394) | (4,576) |
| **Cash flows from financing activities** | | | |
| Payment of accounts receivable agreement | — | (210) | (15) |
| Changes in short-term borrowings | 122 | 332 | (197) |
| Issuance of long-term debt | 3,463 | 2,055 | 2,027 |
| Retirement of long-term debt | (1,545) | (1,589) | (1,145) |
| Redemption of preferred securities | — | (93) | — |
| Distributions to noncontrolling interest of consolidated VIE | (421) | — | — |
| Dividends paid on common stock | (1,065) | (1,249) | (1,716) |
| Proceeds from employee stock plans | 35 | 47 | 72 |
| Other financing activities | (178) | (119) | (111) |
| Net cash flows provided by (used in) financing activities | 411 | (826) | (1,085) |
| **Increase in cash and cash equivalents** | 269 | 123 | 470 |
| **Cash and cash equivalents at beginning of period** | 1,609 | 1,486 | 1,016 |
| **Cash and cash equivalents at end of period** | $ 1,878 | $ 1,609 | $ 1,486 |

See the Combined Notes to Consolidated Financial Statements

**Exelon Corporation and Subsidiary Companies**

**Consolidated Balance Sheets**

| (In millions) | December 31, 2014 | December 31, 2013 |
|---|---|---|
| **ASSETS** | | |
| **Current assets** | | |
| Cash and cash equivalents | $ 1,878 | $ 1,609 |
| Restricted cash and cash equivalents | 271 | 167 |
| Accounts receivable, net | | |
| Customer | 3,482 | 2,981 |
| Other | 1,227 | 1,175 |
| Mark-to-market derivative assets | 1,279 | 727 |
| Unamortized energy contract assets | 254 | 374 |
| Inventories, net | | |
| Fossil fuel | 579 | 276 |
| Materials and supplies | 1,024 | 829 |
| Deferred income taxes | 244 | 573 |
| Regulatory assets | 847 | 760 |
| Assets held for sale | 147 | 14 |
| Other | 865 | 652 |
| Total current assets | 12,097 | 10,137 |
| **Property, plant and equipment, net** | 52,087 | 47,330 |
| **Deferred debits and other assets** | | |
| Regulatory assets | 6,076 | 5,910 |
| Nuclear decommissioning trust funds | 10,537 | 8,071 |
| Investments | 544 | 1,187 |
| Investment in CENG | — | 1,925 |
| Goodwill | 2,672 | 2,625 |
| Mark-to-market derivative assets | 773 | 607 |
| Unamortized energy contract assets | 549 | 710 |
| Pledged assets for Zion Station decommissioning | 319 | 458 |
| Other | 1,160 | 964 |
| Total deferred debits and other assets | 22,630 | 22,457 |
| **Total assets** [a] | $86,814 | $79,924 |

See the Combined Notes to Consolidated Financial Statements

**Exelon Corporation and Subsidiary Companies**

**Consolidated Balance Sheets**

| (In millions) | December 31, 2014 | December 31, 2013 |
|---|---|---|
| **LIABILITIES AND SHAREHOLDERS' EQUITY** | | |
| **Current liabilities** | | |
| Short-term borrowings | $ 460 | $ 341 |
| Long-term debt due within one year | 1,802 | 1,509 |
| Accounts payable | 3,048 | 2,484 |
| Accrued expenses | 1,539 | 1,633 |
| Payables to affiliates | 8 | 116 |
| Deferred income taxes | — | 40 |
| Regulatory liabilities | 310 | 327 |
| Mark-to-market derivative liabilities | 234 | 159 |
| Unamortized energy contract liabilities | 238 | 261 |
| Other | 1,123 | 858 |
| Total current liabilities | 8,762 | 7,728 |
| **Long-term debt** | 19,362 | 17,623 |
| **Long-term debt to financing trusts** | 648 | 648 |
| **Deferred credits and other liabilities** | | |
| Deferred income taxes and unamortized investment tax credits | 13,019 | 12,905 |
| Asset retirement obligations | 7,295 | 5,194 |
| Pension obligations | 3,366 | 1,876 |
| Non-pension postretirement benefit obligations | 1,742 | 2,190 |
| Spent nuclear fuel obligation | 1,021 | 1,021 |
| Regulatory liabilities | 4,550 | 4,388 |
| Mark-to-market derivative liabilities | 403 | 300 |
| Unamortized energy contract liabilities | 211 | 266 |
| Payable for Zion Station decommissioning | 155 | 305 |
| Other | 2,147 | 2,540 |
| Total deferred credits and other liabilities | 33,909 | 30,985 |
| Total liabilities [(a)] | 62,681 | 56,984 |
| **Commitments and contingencies** | | |
| **Shareholders' equity** | | |
| Common stock (No par value, 2,000 shares authorized, 860 and 857 shares outstanding at December 31, 2014 and 2013, respectively) | 16,709 | 16,741 |
| Treasury stock, at cost (35 shares held at December 31, 2014 and 2013) | (2,327) | (2,327) |
| Retained earnings | 10,910 | 10,358 |
| Accumulated other comprehensive loss, net | (2,684) | (2,040) |
| Total shareholders' equity | 22,608 | 22,732 |
| BGE preference stock not subject to mandatory redemption | 193 | 193 |
| Noncontrolling interest | 1,332 | 15 |
| Total equity | 24,133 | 22,940 |
| **Total liabilities and shareholders' equity** | $86,814 | $79,924 |

(a) Exelon's consolidated assets include $8,160 million and $1,755 million at December 31, 2014 and December 31, 2013, respectively, of certain VIEs that can only be used to settle the liabilities of the VIE. Exelon's consolidated liabilities include $2,723 million and $658 million at December 31, 2014 and December 31, 2013, respectively, of certain VIEs for which the VIE creditors do not have recourse to Exelon. See Note 2—Variable Interest Entities.

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, 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 |
| Noncontrolling 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 | — | — | — | — | (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 noncontrolling 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 | — | — | — | — | 727 | — | — | 727 |
| **Balance, December 31, 2013** | 892,034 | $16,741 | $(2,327) | $10,358 | $(2,040) | $ 15 | $193 | $22,940 |
| Net income (loss) | — | — | — | 1,623 | — | 184 | 13 | 1,820 |
| Long-term incentive plan activity | 1,574 | 72 | — | — | — | — | — | 72 |
| Employee stock purchase plan issuances | 960 | 35 | — | — | — | — | — | 35 |
| Tax benefit on stock compensation | — | (8) | — | — | — | — | — | (8) |
| Acquisition of noncontrolling interest | — | (2) | — | — | — | 6 | — | 4 |
| Common stock dividends | — | — | — | (1,071) | — | — | — | (1,071) |
| Preferred and preference stock dividends | — | — | — | — | — | — | (13) | (13) |
| Fair value of financing contract payments | — | (131) | — | — | — | — | — | (131) |
| Noncontrolling interest established upon consolidation of CENG | — | — | — | — | — | 1,548 | — | 1,548 |
| Transfer of CENG pension and non-pension postretirement benefit obligations | — | 2 | — | — | — | — | — | 2 |
| Consolidated VIE dividend to noncontrolling interest | — | — | — | — | — | (421) | — | (421) |
| Reversal of CENG equity method AOCI, net of income taxes | — | — | — | — | (116) | — | — | (116) |
| Other comprehensive loss, net of income taxes | — | — | — | — | (528) | — | — | (528) |
| **Balance, December 31, 2014** | 894,568 | $16,709 | $(2,327) | $10,910 | $(2,684) | $1,332 | $193 | $24,133 |

See the Combined Notes to Consolidated Financial Statements

**Combined Notes to Consolidated Financial Statements**
**(Dollars in millions, except per share data unless otherwise noted)**

## 1. Significant Accounting Policies

### Description of Business

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—Mergers, Acquisitions, and Dispositions for further information regarding the merger transaction.

On April 1, 2014, Generation assumed the operating licenses and corresponding operational control of CENG's nuclear fleet. As a result, Exelon and Generation consolidated CENG's financial position and results of operations into their businesses. Prior to April 1, 2014, Exelon and Generation accounted for CENG as an equity method investment. Refer to Note 5—Investment in Constellation Energy Nuclear Group, LLC for further information regarding the integration 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

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, 2014 and December 31, 2013, 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.

**Combined Notes to Consolidated Financial Statements—(Continued)**
**(Dollars in millions, except per share data unless otherwise noted)**

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 of 99% for certain periods of time, and CENG, of which Generation holds a 50.01% interest. The remaining interests are included in noncontrolling interest on Exelon's Consolidated Balance Sheets. See Note 2—Variable Interest Entities for further discussion of Exelon's and Generation's VIEs and the reversionary interests of the noncontrolling members for these certain subsidiaries.

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, 2014 and December 31, 2013, 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 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.

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.

Each of the Registrant's Consolidated Financial Statements includes the accounts of its subsidiaries. All intercompany transactions have been eliminated.

### Use of Estimates

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

Certain prior year amounts in the registrants' Consolidated Statements of Operations and Comprehensive Income, Consolidated Balance Sheets and Consolidated Statements of Cash Flows have been reclassified between line items for comparative purposes. The reclassifications did not affect any of the Registrants' net income, financial positions, or cash flows from operating activities.

### Accounting for the Effects of Regulation

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

**Combined Notes to Consolidated Financial Statements—(Continued)**
**(Dollars in millions, except per share data unless otherwise noted)**

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 or revenue 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**

***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 Constellation 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**

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 Other income and deductions (interest income) on their Consolidated Statements of Operations and Comprehensive Income.

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 collects certain taxes from customers such as sales and gross receipts taxes, along with other taxes, surcharges, and fees that are levied by state or local governments on the sale or distribution of 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 considers investments purchased with an original maturity of three months or less to be cash equivalents.

### Restricted Cash and Cash Equivalents

Restricted cash and cash equivalents represent funds that are restricted to satisfy designated current liabilities. As of December 31, 2014 and 2013, Exelon Corporate's restricted cash and cash equivalents primarily represented restricted funds for payment of medical, dental, vision and long-term disability benefits. Additionally, as of December 31, 2014 and 2013, Generation's restricted cash and cash equivalents primarily included cash at Antelope Valley required for debt service and construction and cash at Continental Wind and ExGen Texas Power, which is required for debt service and financing of operation and maintenance of the underlying entities. As of December 31, 2014 and 2013, ComEd's restricted cash primarily represented cash collateral held from suppliers associated with ComEd's energy and REC procurement contracts. As of December 31, 2014, PECO's restricted cash primarily represented funds from the sales of assets that were subject to PECO's mortgage indenture. As of December 31, 2014 and 2013, BGE's restricted cash primarily represented funds restricted at its consolidated variable interest entity for repayment of rate stabilization bonds and cash collateral held from suppliers.

Restricted cash and cash equivalents not available to satisfy current liabilities are classified as noncurrent assets. As of December 31, 2014 and 2013, Exelon's and Generation's NDT funds, which are designated to satisfy future decommissioning obligations, were classified as noncurrent assets. As of December 31, 2014, Exelon, Generation, ComEd, PECO and BGE had investments in Rabbi trusts classified as noncurrent assets.

### Allowance for Uncollectible Accounts

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 customer risk segment. At December 31, 2013, BGE estimated the allowance for uncollectible accounts on customer receivables by assigning a reserve factor for each aging bucket. These percentages were derived from a study of billing progression which determined the reserve factors by aging bucket. At December 31, 2014, BGE changed to a methodology for estimating the allowance for uncollectible accounts, which was consistent with ComEd and PECO, as described above. For additional information regarding the change in estimate, refer to Note 6—Accounts Receivable. 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. 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 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 disclose (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 disclosed, 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

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, coal 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

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 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 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

Property, plant and equipment is recorded at original cost. Original cost includes construction-related direct labor and material costs. ComEd, PECO and BGE also include indirect construction costs including labor and related costs of departments associated with supporting construction activities. 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.

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 and Note 23—Supplemental Financial Information for additional information regarding property, plant and equipment.

### Nuclear Fuel

The cost of nuclear fuel is capitalized within property, plant and equipment and charged to fuel expense using the unit-of-production method. Prior to May 16, 2014, the estimated disposal cost of SNF was established per the Standard Waste Contract with the DOE and was expensed through fuel expense at one mill ($0.001) per kWh of net nuclear generation. Effective May 16, 2014, the SNF disposal fee was set to zero by the DOE and Exelon and Generation are not accruing any further costs related to SNF disposal fees until a new fee structure goes into effect. 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.

**Combined Notes to Consolidated Financial Statements—(Continued)**
**(Dollars in millions, except per share data unless otherwise noted)**

### Nuclear Outage Costs

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

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, 2014 and 2013, there were not material capitalized development costs for projects not yet under construction included in Property, plant and equipment, net on Exelon's Consolidated Balance Sheets. Approximately $13 million, $10 million and $4 million of costs were expensed by Exelon for the years ended December 31, 2014, 2013, and 2012, respectively. These costs primarily related to the possible development of new renewable energy projects.

### Capitalized Software Costs

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 [(a)] | Generation [(a)] | ComEd | PECO | BGE |
|---|---|---|---|---|---|
| December 31, 2014 | $596 | $193 | $133 | $84 | $163 |
| December 31, 2013 | 479 | 129 | 101 | 71 | 155 |

| Amortization of capitalized software costs | Exelon [(a)(b)] | Generation [(a)(b)] | ComEd | PECO | BGE [(b)] |
|---|---|---|---|---|---|
| 2014 | $186 | $ 59 | $ 45 | $28 | $ 43 |
| 2013 | 198 | 67 | 52 | 33 | 36 |
| 2012 | 208 | 81 | 56 | 30 | 32 |

(a) On April 1, 2014, Generation assumed operational control of CENG's nuclear fleet. As a result, the 2014 financial results include CENG's financial position and results of operations beginning April 1, 2014.
(b) 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 year ended December 31, 2012.

### Depreciation, Depletion and Amortization

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.

**Combined Notes to Consolidated Financial Statements—(Continued)**
**(Dollars in millions, except per share data unless otherwise noted)**

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 oil and gas reserves are based on internal calculations.

Amortization of regulatory assets and liabilities are recorded over the recovery or refund 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 or income would have originally been recorded in the Registrants' Consolidated Statements of Operations and Comprehensive Income. With exception of income tax-related regulatory assets, generally, 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. Amortization of ComEd's distribution formula rate regulatory asset and ComEd's and BGE's transmission formula rate regulatory assets is recorded to Operating revenues. Amortization of income tax related regulatory assets and liabilities is generally recorded to Income tax expense. With the exception of the regulatory assets and liabilities discussed above, 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.

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**

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 throughout 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 and Comprehensive Income 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**

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.

**Combined Notes to Consolidated Financial Statements—(Continued)**
**(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:

| | 2014 (a) | 2013 | 2012 (b) |
|---|---|---|---|
| Total incurred interest (c) | $1,144 | 1,423 | 1,003 |
| Capitalized interest | 63 | 54 | 67 |
| Credits to AFUDC debt and equity | 37 | 35 | 25 |

(a) On April 1, 2014, Generation assumed operational control of CENG's nuclear fleet. As a result, the 2014 financial results include CENG's financial position and results of operations beginning April 1, 2014.
(b) 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 year ended December 31, 2012.
(c) Includes interest expense to affiliates.

### Guarantees

Exelon recognizes at the inception of a guarantee, a liability for the fair market value of the obligations it has 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 Exelon is released from risk under the guarantee. Depending on the nature of the guarantee, the release from risk of Exelon 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

***Long-Lived Assets.*** Exelon evaluates the carrying value of its long-lived assets or asset groups, excluding goodwill, when circumstances indicate the carrying value of those assets may not be recoverable. Indicators of impairment may include a deteriorating business climate, including, but not limited to, 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. Exelon determines if long-lived assets and asset groups are impaired by comparing their undiscounted expected future cash flows to their carrying value. 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 less costs to sell.

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. The cash flows from the generating units are generally evaluated at a regional portfolio level along with cash flows generated from the 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). 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, Generation'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 other than 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. 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**

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 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 Constellation merger. Because the underlying forecasted transactions remained probable, the fair value of the effective portion of these cash flow hedges was frozen in accumulated OCI and was reclassified to results of operations when the forecasted purchase or sale of the energy commodity occurred. The effect of this decision is that all derivatives executed to hedge economic risk related to 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 sponsors defined benefit pension plans and other postretirement benefit plans for essentially all Generation, ComEd, PECO, BGE and BSC employees. Effective July 14, 2014, Exelon became the sponsor of all of CENG's pension and other postretirement benefit 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.

**Combined Notes to Consolidated Financial Statements—(Continued)**
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### Equity Investment Earnings (Losses) of Unconsolidated Affiliates

Exelon and Generation include equity in earnings from equity method investments in qualifying facilities, power projects and joint ventures, 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.

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 has identified the following new accounting pronouncements that have been recently adopted or issued that management believes may significantly affect 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. This guidance was effective for the Registrants for periods beginning after December 15, 2013 and was required to be applied prospectively. The adoption of this standard had an immaterial effect on the presentation of deferred tax assets at Exelon and Generation and no effect on ComEd, PECO and BGE. There was no effect on the Registrants' results of operations or cash flows.

***Pushdown Accounting (a consensus of the FASB Emerging Issues Task Force)***

In November 2014, the FASB issued authoritative guidance that allows acquired entities to apply pushdown accounting (i.e., reflecting the acquirer's basis of accounting for the acquired entity's assets and liabilities) when an acquirer obtains control of them. At the same time, the SEC rescinded its guidance on pushdown accounting. The SEC's guidance had required pushdown accounting in certain circumstances, made it optional in others and prevented it in still other circumstances. The new guidance is effective immediately for any future transaction or to the most recent event in which an acquirer obtains or obtained control of the acquired entity. The adoption of the guidance had no impact to the financial statements of the Registrants; however, the Registrants will assess the potential impact of the guidance on future acquisitions.

The following recently issued accounting standard is not yet required to be reflected in the combined financial statements of the Registrants.

***Revenue from Contracts with Customers***

In May 2014, the FASB issued authoritative guidance that changes the criteria for recognizing revenue from a contract with a customer. The new guidance replaces existing guidance on revenue recognition, including most industry specific guidance, with a five step model for recognizing and measuring revenue from contracts with customers. The objective of the new standard is to provide a single, comprehensive revenue recognition model for all contracts with customers to improve comparability within industries, across industries and across capital markets. The underlying principle is that an entity will recognize revenue to depict the transfer of goods or services to customers at an amount that the entity expects to be entitled to in exchange for those goods or services. The guidance also requires a number of disclosures regarding the nature, amount, timing and uncertainty of revenue and the related cash flows. The guidance is effective for the Registrants for the first interim period within annual reporting periods beginning on or after December 15, 2016. Early adoption is not permitted. The guidance can be applied retrospectively to each prior reporting period presented (full retrospective method) or retrospectively with a cumulative effect adjustment to retained earnings for initial application of the guidance at the date of initial adoption (modified retrospective method). The Registrants are currently assessing the impacts this guidance may have on their financial positions, results of operations, cash flows and disclosures as well as the transition method that they will use to adopt the guidance.

**Combined Notes to Consolidated Financial Statements—(Continued)**
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## 2. Variable Interest Entities

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 affect the entity's economic performance.

At December 31, 2014 and 2013, Exelon, Generation, and BGE collectively consolidated six and four VIEs or VIE groups, respectively, for which the applicable Registrant was the primary beneficiary. As of December 31, 2014 and 2013, the Registrants had significant interests in six and eight other VIEs, respectively, for which the Registrants do not have the power to direct the entities' activities and, accordingly, were not the primary beneficiary.

### *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, 2014 and 2013 are as follows:

| | December 31, | |
|---|---|---|
| | 2014 (a)(b) | 2013 |
| Current assets | $1,271 | $ 484 |
| Noncurrent assets | 7,580 | 1,905 |
| Total assets | $8,851 | $2,389 |
| Current liabilities | $ 611 | $ 566 |
| Noncurrent liabilities | 2,730 | 774 |
| Total liabilities | $3,341 | $1,340 |

(a) Includes certain purchase accounting adjustments not pushed down to the BGE standalone entity.
(b) Includes total assets of $6.1 billion and total liabilities of $2.1 billion due to the consolidation of CENG. See Note 5— Investment in Constellation Energy Nuclear Group, LLC for additional information.

Except as specifically noted below, the assets in the table above are restricted for settlement of the VIE obligations and the liabilities in the 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 2014, 2013, and 2012, BGE remitted $85 million, $83 million, and $85 million, respectively, to BondCo.

BGE did not provide any additional financial support to BondCo during 2014. 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

**Combined Notes to Consolidated Financial Statements—(Continued)**
**(Dollars in millions, except per share data unless otherwise noted)**

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
- Generation provides 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 242-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 operating and capital funding to the solar entities for ongoing construction, operations and maintenance of the solar power facilities and provides limited recourse related to the Antelope Valley project. In addition, these solar VIE entities have an aggregate amount of outstanding debt with third parties of $642 million, as of December 31, 2014, 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 Companies.** In March 2014, Generation began consolidating retail power VIEs for which Generation is the primary beneficiary as a result of energy supply contracts that give Generation the power to direct the activities that most significantly affect the economic performance of the entities. Generation does not have an equity ownership interest in these entities, but provides approximately $5 million in credit support for the retail power companies. These entities are included in Generation's consolidated financial statements, and the consolidation of the VIEs does not have a material impact on Generation's financial results or financial condition.

**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 with 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 the risks of each of its wind projects and underlying entities, and determined that certain of the entities are VIEs because either the projects have noncontrolling equity 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 generation facilities. While Generation owns 100% of the majority of the wind project entities, nine of the projects have noncontrolling equity interests of 1% held by third parties. Generation's current economic interests in eight of these projects is significantly greater than its stated contractual governance rights and all of these projects have reversionary interest provisions that provide the noncontrolling interest holder with a purchase option, certain of which are considered bargain purchase prices, which, if exercised, transfers ownership of the projects to the noncontrolling interest holder upon either the passage of time or the achievement of targeted financial returns. The ownership agreements with the noncontrolling interests state that Generation is to provide financial support to the projects in proportion to its current

**Combined Notes to Consolidated Financial Statements—(Continued)**
**(Dollars in millions, except per share data unless otherwise noted)**

99% economic interests in the projects. However, no additional support to these projects beyond what was contractually required has been provided during 2014. As of December 31, 2014, 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 relates to the wind generating assets, PPA intangible assets and working capital amounts.

**CENG.** Through March 31, 2014, CENG was operated as a joint venture with EDF Inc. (EDFI) (a subsidiary of EDF) and was governed by a board of ten directors, five of which were appointed by Generation and five by EDF. CENG was designed to operate under joint and equal control of Generation and EDFI through the Board of Directors, subject to the Chairman of the Board's final decision making authority on certain special matters; therefore, CENG was not subject to VIE guidance. Accordingly, Generation's 50.01% interest in CENG was accounted for as an equity method investment. On April 1, 2014, Generation, CENG, and subsidiaries of CENG executed the Nuclear Operating Services Agreement (NOSA) pursuant to which Generation now conducts all activities associated with the operations of the CENG fleet and provides corporate and administrative services to CENG and the CENG fleet for the remaining life of the CENG nuclear plants as if they were a part of the Generation nuclear fleet, subject to the CENG member rights of EDFI. As a result of executing the NOSA, CENG now qualifies as a VIE due to the disproportionate relationship between Generation's 50.01% equity ownership interest and its role in conducting the operational activities of CENG and the CENG fleet conveyed through the NOSA. Further, since Generation is conducting the operational activities of CENG and the CENG fleet, Generation qualifies as the primary beneficiary of CENG and, therefore, is required to consolidate the financial position and results of operations of CENG. On April 1, 2014, Exelon and Generation derecognized Generation's equity method investment in CENG and reflected all assets, liabilities, and the EDFI noncontrolling interest in CENG at fair value on the consolidated balance sheets of Exelon and Generation, resulting in the recognition of a $261 million gain in their respective Consolidated Statements of Operations and Comprehensive Income for the year ended December 31, 2014. For additional information on this transaction refer to Note 5—Investment in Constellation Energy Nuclear Group, LLC.

Generation and Exelon, where indicated, provide the following support to CENG (See Note 25—Related Party Transactions and Note 5—Investment in Constellation Energy Nuclear Group, LLC for additional information regarding Generation and Exelon's transactions with CENG):

- under the NOSA, Generation conducts all activities related to the operation of the CENG nuclear generation fleet owned by CENG subsidiaries (the CENG fleet) and provides corporate and administrative services for the remaining life and decommissioning of the CENG nuclear plants as if they were a part of the Generation nuclear fleet, subject to the CENG member rights of EDFI,
- under the Power Services Agency Agreement (PSAA), Generation provides scheduling, asset management, and billing services to the CENG fleet for the remaining operating life of the CENG nuclear plants,
- under power purchase agreements with CENG, Generation purchased 85% of the available output generated by the CENG nuclear plants through the end of 2014 and will purchase 50.01% from 2015 through the end of the operating life of each respective plant,
- Generation provided a $400 million loan to CENG (see Note 5—Investment in Constellation Energy Nuclear Group, LLC for more details),
- Generation executed an Indemnity Agreement pursuant to which Generation agreed to 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 guarantees Generation's obligations under this Indemnity Agreement. (See Note 22—Commitments and Contingencies for more details),
- in connection with CENG's severance obligations, Generation has agreed to reimburse CENG for a total of approximately $6 million of the severance benefits paid or to be paid from 2013 through 2016. As of December 31, 2014, the remaining obligation is approximately $3 million,
- Generation and EDFI share in the $637 million of contingent payment obligations for the payment of contingent retrospective premium adjustments for the nuclear liability insurance (See Note 22—Commitments and Contingencies for more details),
- Generation provides a guarantee of approximately $7 million associated with hazardous waste management facilities and underground storage tanks. In addition, EDFI executed a reimbursement agreement that provides reimbursement to Exelon for 49.99% of any amounts paid by Generation under this guarantee,

**Combined Notes to Consolidated Financial Statements—(Continued)**
**(Dollars in millions, except per share data unless otherwise noted)**

- Generation and EDFI are the members-insured with Nuclear Electric Insurance Limited and have assigned the loss benefits under the insurance and the NEIL premium costs to CENG and guarantee the obligations of CENG under these insurance programs in proportion to their respective member interests (see Note 22—Commitments and Contingencies for more details), and
- Exelon has executed an agreement to provide up to $245 million to support the operations of CENG as well as a $165 million guarantee of CENG's cash pooling agreement with its subsidiaries.

For each of the consolidated VIEs, except as otherwise noted:

- The assets of the VIEs are restricted and can only be used to settle obligations of the respective VIE;
- Exelon, Generation and BGE did not provide any additional material financial support to the VIEs;
- Exelon, Generation and BGE did not have any material contractual commitments or obligations to provide financial support to the VIEs; and
- the creditors of the VIEs did not have recourse to Exelon's, Generation's or BGE's general credit.

As of December 31, 2014 and 2013, ComEd and PECO did not have any material consolidated VIEs.

**Combined Notes to Consolidated Financial Statements—(Continued)**
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***Assets and Liabilities of Consolidated VIEs***

Included within the consolidated VIE table above are assets and liabilities of certain consolidated VIEs for which the assets can only be used to settle obligations of those VIEs, and liabilities that creditors, or beneficiaries, do not have recourse to the general credit of the Registrants. As of December 31, 2014 and 2013, these assets and liabilities primarily consisted of the following:

| | December 31, | |
|---|---|---|
| | 2014 | 2013 |
| Cash and cash equivalents | $ 392 | $ 62 |
| Restricted cash | 117 | 80 |
| Accounts receivable, net | | |
| Customer | 297 | 260 |
| Other | 57 | — |
| Mark-to-market derivatives assets | 171 | 21 |
| Inventory | | |
| Materials and supplies | 172 | — |
| Other current assets | 33 | 34 |
| Total current assets | 1,239 | 457 |
| Property, plant and equipment, net | 4,638 | 1,171 |
| Nuclear decommissioning trust funds | 2,097 | — |
| Goodwill | 47 | — |
| Mark-to-market derivatives assets | 44 | — |
| Other noncurrent assets | 95 | 127 |
| Total noncurrent assets | 6,921 | 1,298 |
| Total assets | $8,160 | $1,755 |
| Long-term debt due within one year | $ 87 | $ 85 |
| Accounts payable | 292 | 170 |
| Accrued expenses | 111 | 26 |
| Mark-to-market derivative liabilities | 24 | 29 |
| Unamortized energy contracts (liabilities) | 22 | 5 |
| Other current liabilities | 25 | 5 |
| Total current liabilities | 561 | 320 |
| Long-term debt | 212 | 298 |
| Asset retirement obligations | 1,763 | — |
| Pension obligation[(a)] | 9 | — |
| Unamortized energy contracts (liabilities) | 51 | 28 |
| Other noncurrent liabilities | 127 | 12 |
| Noncurrent liabilities | 2,162 | 338 |
| Total liabilities | $2,723 | $ 658 |

(a) Includes the CNEG Retail Gas' pension obligation, which is presented as a net asset balance within the Prepaid Pension asset line item on Generation's balance sheet. See Note 16—Retirement Benefits for additional details.

***Unconsolidated Variable Interest Entities***

Exelon's and Generation's variable interests in unconsolidated VIEs generally include equity investments and energy purchase and sale contracts. For the equity investments, the carrying amount of the investments is reflected on Exelon's Consolidated Balance Sheets in Investments and Other assets. For the energy purchase and sale contracts and the fuel purchase commitments (commercial agreements), the carrying amount of assets and liabilities in Exelon'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.

**Combined Notes to Consolidated Financial Statements—(Continued)**
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As of December 31, 2014 and 2013, Exelon and Generation had significant unconsolidated variable interests in six and eight VIEs, respectively, for which Exelon or Generation, as applicable, was not the primary beneficiary; including certain equity method investments and certain commercial agreements. The decrease in the number of unconsolidated VIEs is due to the sale of Generation's ownership interest in four unconsolidated VIEs in 2014, offset by the execution of an energy purchase and sale agreement with an unconsolidated VIE and an equity investment in another unconsolidated VIE. The following tables present summary information about Exelon and Generation's significant unconsolidated VIE entities:

| December 31, 2014 | Commercial Agreement VIEs | Equity Investment VIEs | Total |
|---|---|---|---|
| Total assets [(a)] | $506 | $ 91 | $597 |
| Total liabilities [(a)] | 237 | 49 | 286 |
| Exelon's ownership interest in VIE [(a)] | — | 9 | 9 |
| Other ownership interests in VIE [(a)] | 269 | 33 | 302 |
| Registrants' maximum exposure to loss: | | | |
| Carrying amount of equity method investments | — | 13 | 13 |
| Contract intangible asset | 9 | — | 9 |
| Debt and payment guarantees | — | 3 | 3 |
| Net assets pledged for Zion Station decommissioning [(b)] | 27 | — | 27 |

| December 31, 2013 | Commercial Agreement VIEs | Equity Investment VIEs | Total |
|---|---|---|---|
| Total assets [(a)] | $128 | $332 | $460 |
| Total liabilities [(a)] | 17 | 123 | 140 |
| Exelon's ownership interest in VIE [(a)] | — | 86 | 86 |
| Other ownership interests in VIE [(a)] | 111 | 123 | 234 |
| Registrants' maximum exposure to loss: | | | |
| Carrying amount of equity method 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 |

(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 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 $319 million and $458 million as of December 31, 2014 and December 31, 2013, respectively; offset by payables to ZionSolutions LLC of $292 million and $414 million as of December 31, 2014 and December 31, 2013, respectively. These items are included to provide information regarding the relative size of the ZionSolutions LLC unconsolidated VIE.

For each unconsolidated VIE, Exelon and Generation assessed 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.** Generation has several energy purchase and sale agreements with generating facilities. Generation has evaluated the significant agreements, ownership structures and risks of each entity, and determined that certain of the entities are VIEs because the entity absorbs risk through the sale of fixed price power and renewable energy credits. Generation has reviewed the entities and has determined that Generation is not the primary beneficiary of the VIEs because Generation does not have the power to direct the activities that most significantly impact the VIEs economic performance.

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

**Combined Notes to Consolidated Financial Statements—(Continued)**
**(Dollars in millions, except per share data unless otherwise noted)**

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 and 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 and Energy Generating Facilities.** Generation has several equity investments in energy development projects and 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 the entity has an insufficient amount of equity at risk to finance its activities, 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 that most significantly impact the VIEs economic performance.

***ComEd, PECO and BGE***

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.

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### 3. Regulatory Matters

The following matters below discuss the current status of Exelon's material regulatory and legislative proceedings.

#### Illinois Regulatory Matters

***Energy Infrastructure Modernization Act***

*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 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, 2014, and December 31, 2013, ComEd had a regulatory asset associated with the distribution formula rate of $371 million and $463 million, respectively. The regulatory asset associated with distribution true-up is amortized to Operating revenues as the associated amounts are recovered through rates.

*Annual Reconciliation*

*2014 Filing.* On April 16, 2014, ComEd filed its annual distribution formula rate to request a total increase to the revenue requirement of $269 million. On December 11, 2014, the ICC issued its final order which increased the revenue requirement by $232 million, reflecting an increase of $160 million for the initial revenue requirement for 2014 and an increase of $72 million related to the annual reconciliation for 2013. Approximately $23 million of the total $37 million revenue requirement disallowance is recoverable through other rider-based mechanisms. The rate increase was set using an allowed return on capital of 7.06% (inclusive of an allowed return on common equity of 9.25% for 2014 less a performance metrics penalty of 5 basis points for the 2013 reconciliation). The rates took effect in January 2015. ComEd and intervenors requested a rehearing on specific issues, which was denied by the ICC on January 28, 2015.

*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. 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 final revenue requirement reflected the impacts of Senate Bill 9, which became effective in May 2013 and clarified the intent of EIMA on three issues: 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. 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, which was subsequently withdrawn.

*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, reflecting 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. The Illinois Appellate Court upheld the ICC's decision on the issues on appeal. 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. 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. The Illinois Appellate Court reaffirmed the ICC's order.

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*Formula Rate Structure Investigation*

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 reduced 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.

*Appeal of Initial Formula Rate Tariff*

On March 26, 2014, the Illinois Appellate Court issued an opinion with respect to ComEd's appeal of the ICC's order relating to ComEd's initial formula rate tariff. The most significant financial issues under appeal related to ICC findings that were counter to the formula rate legislation and were clarified by subsequent legislation (Senate Bill 9). Therefore, only a subset of the issues originally appealed remained. The Court found against ComEd on each of the remaining issues: compensation related adjustments, billing determinants and the use of certain allocators. The Court's opinion has no accounting impact as ComEd recorded the distribution formula regulatory asset consistent with the ICC's final Order.

ComEd asked the Illinois Supreme Court to hear the issue of allocation between State and Federal regulatory jurisdictions. On June 4, 2014, ComEd filed a Petition for Leave to Appeal with the Illinois Supreme Court solely on the issue of allocation between FERC and ICC jurisdictional costs. On July 2, 2014, the ICC filed its Answer to the Petition, arguing that Supreme Court review is not necessary or appropriate. Under the procedural rules of the Illinois Supreme Court, ComEd is not allowed to reply to the ICC filing. There is no set time by which the Court must rule on the Petition. ComEd cannot predict whether the Court will grant the appeal, or if it does, the ultimate outcome.

*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.

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 on their AMI implementation progress. In March 2014, ComEd filed a petition with the ICC for approval to accelerate the deployment of AMI meters. On June 11, 2014, the ICC approved ComEd's accelerated deployment plan which allows for the installation of more than four million smart meters throughout ComEd's service territory by 2018, three years in advance of the originally scheduled 2021 completion date. To date, nearly 550,000 smart meters have been installed in the Chicago area.

***Appeal of 2007 Illinois Electric Distribution Rate Case.*** 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).

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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 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 approximately $37 million, including interest. On September 18, 2014, the ICC issued an order requiring the refund to occur in November 2014, rather than the eight month period previously approved. The refund was included with the Rider AMP refund discussed below. Former ComEd customers were eligible for a refund. ComEd was fully reserved for this liability at December 31, 2013. As of December 31, 2014 ComEd had refunded substantially all amounts to customers.

***Advanced Metering Program Proceeding.*** As part of ComEd's 2007 Rate Case, the ICC approved recovery of costs associated with ComEd's Rider SMP for the limited purpose of implementing a pilot program for AMI. In October 2009, the ICC approved ComEd's AMI pilot program and associated rider (Rider AMP). ComEd collected approximately $24 million under Rider AMP and had no collections under Rider SMP through December 31, 2014. In ComEd's 2010 electric distribution rate case, the ICC approved ComEd's transfer of certain other costs from recovery under Rider AMP to recovery through electric distribution rates.

Several parties, including the Illinois Attorney General, appealed the ICC's orders on Rider SMP and Rider AMP. The Illinois Appellate Court reversed the ICC's approval of the cost recovery provisions of Rider SMP and Rider AMP on September 30, 2010 and March 19, 2012, respectively. In both cases, the Court ruled that the ICC's approval of the rider constituted single-issue ratemaking. ComEd filed Petitions for Leave to Appeal to the Illinois Supreme Court, which were denied.

In October 2013, the ICC opened an investigation on Rider AMP to determine if a refund is required and if so, to determine the appropriate refund amount. The ALJ presiding over the investigation requested each party provide a pre-trial memorandum describing their positions, which were submitted on April 10, 2014. The ICC Staff and the Illinois Attorney General proposed a refund of $14.6 million, representing the amount they claim was collected under Rider AMP since September 30, 2010, the date the Illinois Appellate Court reversed the ICC's approval of the cost recovery provisions of Rider SMP. During the second quarter of 2014, ComEd reached a tentative agreement to jointly resolve the disputed refund claim. On September 18, 2014, the ICC approved a refund of $9.5 million plus interest to be issued to current customers in November 2014. Former ComEd customers also were eligible for a refund. As of December 31, 2014 ComEd had refunded substantially all amounts to customers.

***Grand Prairie Gateway Transmission Line.*** On December 2, 2013, ComEd filed a request to obtain the ICC's approval to construct a 60-mile overhead 345kV transmission line that traverses Ogle, DeKalb, Kane and DuPage Counties in Northern Illinois. On May 28, 2014, in a separate proceeding, FERC issued an order granting ComEd's request to include 100% of the capital costs recorded to construction work in progress during construction of the line in ComEd's transmission rate base. If the project is cancelled or abandoned for reasons beyond ComEd's control, FERC approved the ability for ComEd to recover 100% of its prudent costs incurred after May 21, 2014 and 50% of its costs incurred prior to May 21, 2014 in ComEd's transmission rate base. On October 22, 2014, the ICC issued an order approving ComEd's Grand Prairie Gateway Project over the objection of numerous landowners and the City of Elgin. Four parties filed timely applications for rehearing before the ICC. On November 25, 2014, the ICC denied the rehearing application filed by the Forest Preserve District of Kane County, but granted rehearing on the application of certain landowners who requested that the ICC consider an alternate route for a three-mile segment of the line in Kane County. The rehearing proceeding is currently pending and the ICC must enter a final order on rehearing by April 24, 2015. On December 10, 2014, the ICC denied the remaining two applications for rehearing. On January 15, 2015, those two parties, the City of Elgin and the SKP landowner group and Utility Risk Management Corporation (collectively, the SKP/URMC party), each filed a Notice of Appeal with the Second District Appellate Court. On February 3, 2015, the ICC filed motions with the Second District Appellate Court seeking to extend the time for the ICC to file the record on appeal until after the ICC issues its Order on rehearing. The ICC also filed a motion to consolidate those appeals. ComEd expects to begin construction of the line in the second quarter of 2015 with an in-service date expected in the second quarter of 2017.

***Utility Consolidated Billing and Purchase of Receivables.*** ComEd is 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

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and purchased receivables. As of December 31, 2014, the balance of purchased accounts receivable was $139 million. ComEd recovers from RES and customers the costs for implementing and operating the program under an ICC approved tariff. 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.*** ComEd is permitted to recover its electricity procurement costs from retail customers without mark-up. 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.

ComEd is required to purchase an increasing percentage of the electricity 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. All associated costs are recoverable from customers.

On December 18, 2013, the ICC approved the IPA's 2014-2019 procurement plan, which provided for two separate energy procurements during 2014 to address potential fluctuations in energy due to customers switching between ComEd and competitive electric generation suppliers. During May and September 2014, ComEd conducted energy procurements to meet the IPA's 2014-2019 procurement plan. On December 17, 2014, the ICC approved the IPA's 2015-2020 procurement plan. See Note 22—Commitments and Contingencies for additional information on ComEd's energy commitments.

***FutureGen Industrial Alliance, Inc.*** 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 ComEd and Ameren 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 ComEd and Ameren to recover these costs from their electric distribution customers through the use of a tariff, regardless of whether they purchase electricity from ComEd or Ameren, 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 July 22, 2014, the Illinois Appellate Court issued its ruling re-affirming the ICC's order requiring ComEd to enter into the sourcing agreement with FutureGen and allowing the use of a tariff to recover its costs. ComEd decided not to appeal the Illinois Appellate Court's decision to the Illinois Supreme Court. However, the competitive electric generation suppliers and several large consumers petitioned for leave to appeal the Illinois Appellate Court's decision. On November 26, 2014, the Illinois Supreme Court granted the petition. A decision from the Illinois Appellate Court is expected in late 2015.

A significant portion of the cost of the development of FutureGen was being funded by the DOE under the American Recovery and Reinvestment Act of 2009. In early February 2015, the DOE suspended funding for the project until further clarity could be obtained on certain significant hurdles facing the project, including the outcome of the litigation described above. Whether or not the DOE funding will be reinstated at some later date is unknown at this time.

ComEd executed the sourcing agreement with FutureGen in accordance with the ICC's order. In addition, ComEd filed a petition with the ICC seeking approval of the tariff allowing for the recovery of its costs associated with the FutureGen contract from all of its electric distribution customers, which was approved by the ICC on September 30, 2014. Depending on 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.

**Combined Notes to Consolidated Financial Statements—(Continued)**
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***Energy Efficiency and Renewable Energy Resources.*** 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 January 2014, the ICC approved ComEd's third three-year Energy Efficiency and Demand Response Plan covering the period June 2014 through May 2017. The plans are designed to meet Illinois' energy efficiency and demand response goals through May 2017, 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 through 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 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.

Illinois utilities are 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 by Illinois legislation. As of December 31, 2014, ComEd had purchased sufficient renewable energy resources or equivalents, such as RECs, to comply with the Illinois 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.*** 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 during 2015 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—Income Taxes for additional information.

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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.*** 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 procured 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. PECO entered into contracts with PAPUC approved bidders, including Generation, for its five competitive procurements. 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 submit a plan to allow its low-income Customer Assistance Program (CAP) customers to purchase their generation supply from EGSs beginning in April 2014. On May 1, 2013, PECO filed its CAP Shopping Plan with the PAPUC. By Order entered on January 24, 2014, the PAPUC approved PECO's plan, with modifications, to make CAP shopping available beginning April 15, 2014. On March 20, 2014, the Office of Consumer Advocate (OCA) and low-income advocacy groups filed an appeal and emergency request for a stay with the Pennsylvania Commonwealth Court, claiming that the PAPUC-ordered CAP Shopping plan does not contain sufficient protections for low-income customers. On March 28, 2014, the Commonwealth Court issued the requested stay, pending a full review of the appeal. Pending the Commonwealth Court's review, PECO will not implement CAP Shopping. The Commonwealth Court's decision is expected in 2015.

On March 10, 2014, PECO filed its third DSP Program with the PAPUC. The program has a 24-month term from June 1, 2015 through May 31, 2017, and complies with electric generation procurement guidelines set forth in Act 129. On August 28, 2014, PECO filed a Joint Petition for Partial Settlement, which affirmed PECO's procurement plan for Residential and Small Commercial customers. On December 4, 2014, the PAPUC approved PECO's third DSP Program, as modified by the Joint Petition for Partial Settlement, without modification or limitation. Separate from the Joint Petition for Partial Settlement, the PAPUC also approved other items related to the program. The plan outlines how PECO will purchase electric supply for default service customers. PECO will procure electric supply through four competitive procurements for fixed price full requirements contracts of two years or less for the residential classes and small and medium commercial classes and spot market price full requirement contracts for the large commercial and industrial class load.

***Smart Meter and Smart Grid Investments.*** 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 electric 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 all of the remaining smart meters, for a total of 1.7 million smart meters, on an accelerated basis by the second quarter of 2015. In total, PECO currently expects to spend up to $583 million, excluding the cost of the original meters (as further described below), on its smart meter infrastructure and approximately $155 million on smart grid investments through final deployment of which $200 million has been funded by SGIG as discussed below. As of December 31, 2014, PECO has spent $540 million and $119 million on smart meter and smart grid infrastructure, respectively, not including the DOE reimbursements received.

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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 were used by PECO to offset the total impact to ratepayers of the smart meter deployment required by Act 129. As of the third quarter of 2014, PECO received all of the $200 million, including $4 million for sub-recipients, in reimbursements. On October 15, 2014, the DOE issued a Close Out of Post-Award Project Cost Verification Audit, in which it was determined that PECO fully met its required cost share, and the audit was closed with no further action required.

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 remained 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. 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. Pursuant to the January 23, 2014, vendor agreement, PECO reclassified the regulatory asset balance as a receivable, which has been fully collected, with no gain or loss impacts on future results of operations. On March 14, 2014, PECO filed its quarterly smart meter recovery surcharge with the PAPUC which included PECO's proposed treatment of the final agreement with the vendor. On March 27, 2014, the PAPUC approved the surcharge as proposed by PECO.

***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 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.

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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. In its February 20, 2014 Final Order, the PAPUC stated that it does not expect to make a decision as to whether it will prescribe additional demand response obligations until 2015. Any decision reached would affect PECO's EE&C Plan subsequent to its Phase II Plan.

On February 28, 2014, 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, 2014 to May 31, 2016. PECO proposed to fund the estimated $10 million annual costs of the program by modifying incentive levels for other Phase II programs. The costs of the DLC program will be recovered through PECO's Energy Efficiency Program Charge along with other Phase II Plan costs. In an April 23, 2014 Tentative Order, the PAPUC granted PECO's Petition. The Order became final on May 5, 2014.

***Alternative Energy Portfolio Standards.*** 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 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.

***Pennsylvania Retail Electricity and Gas Markets.*** Beginning in 2011, the PAPUC issued an order outlining the next steps in its investigation into the status of competition in Pennsylvania's retail electricity market. The PAPUC found that the existing default

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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. Through various orders, the PAPUC issued default electric service pricing for customers in PECO's service territory. See Pennsylvania procurement proceedings discussed above for additional details.

In early 2014, the extreme weather in PECO's service territory resulted in increased electricity commodity costs causing certain shopping customers to receive unexpectedly high utility bills. In response to a significant number of customer complaints throughout Pennsylvania, on April 3, 2014, the PAPUC unanimously voted to adopt two rulemaking orders to address the issue. The first rulemaking order requires electric generation suppliers to provide more consumer education regarding their contract. The second rulemaking order requires electric distribution companies to enable customers to switch suppliers within three business days (known as accelerated switching). The improved customer education and accelerated switching were to be in place within 30 days and six months of approval of the orders, respectively. The orders became final on June 14, 2014. On December 4, 2014, the PAPUC approved PECO's implementation plan (known as Bill on Supplier Switch), allowing PECO to implement accelerated switching by the December 15, 2014 deadline.

On September 12, 2013, the PAPUC issued an Order that initiated an investigation into Pennsylvania's natural gas retail market, including the role of the existing default service model and opportunities for market enhancements. On December 18, 2014, the PAPUC issued a Final Order directing the Office of Competitive Market Oversight to continue its investigation, confirming that natural gas distribution companies should remain with the default service model for the time being and directing establishment of a working group to examine other competitive issues. Comments on the Final Order were due on February 2, 2015. PECO will continue to monitor the Order and assess compliance, as necessary.

***Pennsylvania Act 11 of 2012.*** 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. On February 5, 2015, PECO filed a petition to modify its approved Gas LTIIP with the PAPUC. If approved, the modification would allow PECO to further accelerate the replacement of existing gas mains and also included a plan for the relocation of meters from indoors to outside in accordance with a recent PAPUC rulemaking.

### Maryland Regulatory Matters

***2014 Maryland Electric and Gas Distribution Rate Case.*** On July 2, 2014, and as amended on September 15, 2014, BGE filed for electric and gas base increases with the MDPSC, ultimately requesting increases of $99 million and $68 million, respectively.

On October 17, 2014, BGE filed with the MDPSC a unanimous settlement agreement (the Settlement Agreement) reached with all parties to the case under which it would receive an increase of $22 million in electric base rates and an increase of $38 million in gas base rates. The Settlement Agreement establishes new depreciation rates which have the effect of decreasing annual depreciation expense by approximately $20 million, primarily for electric. On December 4, 2014, the Public Utility Law Judge issued a proposed order approving the Settlement Agreement without modification, which became a final order on December 12, 2014. The approved distribution rate order authorizing BGE to increase electric and gas distribution rates became effective for services rendered on or after December 15, 2014.

***2013 Maryland Electric and Gas Distribution Rate Case.*** On May 17, 2013, and as amended on August 23, 2013, BGE filed for electric and gas base increases with the MDPSC, ultimately requesting increases of $83 million and $24 million, 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 (the "ERI initiative") in response to a MDPSC order through a surcharge separate from base rates.

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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, and an allowed return on equity of 9.75% and 9.60%, respectively. Rates became effective for services rendered on or after December 13, 2013. The MDPSC also authorized BGE to recover through a surcharge mechanism costs associated with five ERI initiative programs designed to accelerate electric reliability improvements premised upon the condition that the MDPSC approve specific projects in advance of cost recovery. On March 31, 2014, after reviewing comments filed by the parties and conducting a hearing on the matter, the MDPSC approved all but one project proposed for completion in 2014 as part of the ERI initiative. The ERI initiative surcharge became effective June 1, 2014. On November 3, 2014, BGE filed a surcharge update including a true-up of cost estimates included in the 2014 surcharge, along with its work plan and cost estimates for 2015, to be included in the 2015 surcharge. At its December 17, 2014 weekly Administrative Meeting, the MDPSC approved BGE's 2014 annual report, 2015 work plan and the 2015 surcharge.

In January 2014, the residential consumer advocate in Maryland filed an appeal to the order issued by the MDPSC on December 13, 2013 in BGE's 2013 electric and gas distribution rate cases. The residential consumer advocate filed its related legal memorandum on August 22, 2014, challenging the MDPSC's approval of the ERI initiative surcharge. BGE submitted a response to the appeal on October 15, 2014, and a hearing was held on November 17, 2014. BGE cannot predict the outcome of this appeal. If the residential consumer advocate's appeal is successful, BGE could recover ERI expenditures through other regulatory mechanisms.

***2012 Maryland Electric and Gas Distribution Rate Case.*** 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 for increases in annual distribution service revenue of $81 million and $32 million, respectively, and an allowed return on equity of 9.75% and 9.60%, respectively. The 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 the merger integration costs, including severance, incurred during the test year for the Exelon and Constellation merger. 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.

***2011 Maryland Electric and Gas Distribution Rate Case.*** 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.

***Smart Meter and Smart Grid Investments.*** In August 2010, the MDPSC approved a comprehensive smart grid initiative for BGE that included the planned installation of 2 million residential and commercial electric and gas smart meters at an expected total cost of $480 million of which $200 million was recovered through a grant from the DOE. 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, 2014 and December 31, 2013, BGE recorded a regulatory asset of $128 million and $66 million, respectively, representing incremental costs, depreciation and amortization, and a debt return on fixed assets related to its AMI program. As part of the settlement in BGE's 2014 electric and gas distribution rate case discussed above, the cost of the retired non-AMI meters will be amortized over 10 years.

On February 26, 2014, the MDPSC issued an order authorizing BGE to impose a $75 upfront fee and an $11 recurring fee to customers electing to opt-out of BGE's smart meter installation program, effective the later of the first full billing cycle following July 1, 2014, or the AMI installation date in a customer's community. The fees authorized by the order will be reviewed after an initial 12 to 18 month period. On November 25, 2014, the MDPSC issued a decision approving BGE's proposal to automatically enroll unresponsive customers into the opt-out program and to charge those customers opt-out fees after BGE has exhausted attempts to schedule a meter installation. The ultimate impact of opt-out 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.

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***New Electric Generation.*** 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 700MW 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, 2014, 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 challenged 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.*** 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. During the summer of 2014, an evaluation of the reports filed by BGE and other Maryland utilities was undertaken by consultants on behalf of the MDPSC and MDPSC Staff. The MDPSC Staff also proposed standards for reliability during major events and estimated times of restoration as well as undertaking an evaluation of performance-based ratemaking principles and methodologies that would more directly and transparently align reliable service with the utilities' distribution rates and that reduce returns or otherwise penalize sub-standard performance. The MDPSC held hearings in September 2014. 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.*** 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. On January 29, 2014, the MDPSC issued a decision conditionally approving the first five years of BGE's plan and surcharge. On March 26, 2014, the Maryland PSC approved as filed BGE's proposed 2014 project list, tariff and associated surcharge amounts, with a surcharge that became effective April 1, 2014. On November 17, 2014, BGE filed a surcharge update including a true-up of costs estimates included in the 2014 surcharge, along with its 2015 project list and cost estimates to be included in the 2015 surcharge. The filing was approved with a revised surcharge effective January 1, 2015. At its December 17, 2014 weekly Administrative Meeting, the MDPSC approved BGE's 2015 project list and the proposed surcharge for 2015. BGE will defer the difference between the surcharge revenues and program costs as a regulated asset or liability, which was immaterial to Exelon and BGE as of December 31, 2014.

In February 2014, the residential consumer advocate in Maryland filed an appeal with the Baltimore City Circuit Court to the decision issued by the MDPSC on BGE's infrastructure replacement plan. On September 5, 2014, the Baltimore City Circuit Court affirmed the MDPSC decision on BGE's infrastructure replacement plan and associated surcharge. On October 10, 2014, the residential consumer advocate noticed its appeal to the Maryland Court of Special Appeals from the judgment entered by the Baltimore City Circuit Court, however, a procedural schedule for the matter has not yet been set.

**New York Regulatory Matters**

***Ginna Nuclear Power Plant Reliability Support Services Agreement.*** Ginna Nuclear Power Plant's (Ginna) prior period fixed-price PPA contract with Rochester Gas & Electric Company (RG&E) expired in June 2014. In light of the expiration of the agreement, Ginna advised the New York Public Service Commission (NYPSC) and ISO-NY that in absence of a reliability need, Ginna management would make a recommendation, subject to approval by the CENG board, that Ginna be retired as soon as practicable. A formal study conducted by the ISO-NY and RG&E concluded that the Ginna nuclear plant needs to remain in operation to maintain the reliability of the transmission grid in the Rochester region through 2018 when planned transmission system upgrades are expected to be completed. In November, in response to a petition filed by Ginna, the NYPSC directed Ginna and RG&E to negotiate a Reliability Support Services Agreement (RSSA). On February 13, 2015, regulatory filings, including RSSA terms negotiated between Ginna and RG&E, to support the continued operation of Ginna for reliability purposes were made with the NYPSC and with FERC for their approval. While the RSSA is expected to be approved, in absence of such an agreement and in the event the plant was retired before the current license term ends in 2029, Exelon's and Generation's results of operations could be adversely affected by increased depreciation rates, impairment charges, severance costs, and accelerated future decommissioning costs, among other items. However, it is not expected that such impacts would be material to Exelon's or Generation's results of operations.

**Federal Regulatory Matters**

***Transmission Formula Rate.*** ComEd's and BGE's transmission rates are each established based on a FERC-approved formula. ComEd and BGE are required to file an annual update to the FERC-approved formula on or before May 15, with the resulting rates effective on June 1 of the same year. The 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 in effect beginning June 1 of the prior year and actual costs incurred for that year. ComEd and BGE record regulatory assets or regulatory liabilities and corresponding increases or decreases to operating revenues for any differences between the revenue requirement in effect and ComEd's and BGE's best estimate of the revenue requirement expected to be approved by the FERC for that year's reconciliation. As of December 31, 2014, and 2013, ComEd had a regulatory asset associated with the transmission formula rate of $21 million and $17 million, respectively, and BGE had a net regulatory asset associated with the transmission formula rate of $1 million and a net regulatory liability which was not material as of December 31, 2013. The regulatory asset associated with transmission true-up is amortized to Operating revenues as the associated amounts are recovered through rates.

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In April 2014, ComEd filed its annual 2014 formula rate update with the FERC, reflecting an increased revenue requirement of $22 million, including an increase of $36 million for the initial revenue requirement, offset by a decrease of $14 million related to the annual reconciliation. The filing established the revenue requirement used to set rates that took effect in June 2014. ComEd's 2014 formula transmission rate provides for a weighted average debt and equity return on transmission rate base of 8.62%, inclusive of an allowed return on common equity of 11.50%, a decrease from the 8.70% average debt and equity return previously authorized. The time period for any challenges to ComEd's annual 2014 formula rate update expired in October 2014 with no challenges submitted.

In April 2013, ComEd filed its annual 2013 formula rate update with the FERC, reflecting an increased revenue requirement of $68 million, including an increase of $38 million for the initial revenue requirement and an increase of $30 million related to the annual reconciliation. The filing established the revenue requirement used to set rates that took effect in June 2013. ComEd's 2013 formula transmission rate provides for a weighted average debt and equity return on transmission rate base of 8.70%, inclusive of an allowed return on common equity of 11.50%, a decrease from the 8.91% average debt and equity return previously authorized. The time period for any challenges to ComEd's annual 2013 formula rate update expired in October 2013 with no challenges submitted.

As part of the FERC-approved settlement of ComEd's 2007 transmission rate case, the rate of return on common equity is 11.50% and the common equity component of the ratio used to calculate the weighted average debt and equity return for the transmission formula rate is currently capped at 55%.

In April 2014, BGE filed its 2014 formula rate update with the FERC reflecting an increased revenue requirement of $14 million, including an increase of $9 million for the initial revenue requirement and an increase of $5 million related to the annual reconciliation. The annual update established the revenue requirement used to set rates that took effect in June 2014. The time period for any challenges to BGE's annual update expired in October 2014 with no challenges submitted.

BGE's 2014 formula transmission rate provides for a weighted average debt and equity return on transmission rate base of 8.53%, an increase from the 8.35% average debt and equity return previously authorized. As part of the FERC-approved settlement of BGE's 2005 transmission rate case in 2006, the 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.*** 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) and a 50 basis point incentive for participating in PJM (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 revenues subject to refund are limited to a fifteen month period and the earliest date from which the base ROE 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.

On August 21, 2014, FERC issued an order in the BGE and PHI companies' proceeding, which established hearing and settlement judge procedures for the complaint, and set a refund effective date of February 27, 2013. BGE, the PHI companies and the parties began settlement discussions under the guidance of a FERC administrative law judge on September 23, 2014. On November 24, 2014, the Settlement Judge informed FERC and the Chief Judge that the parties had reached an impasse and determined that a settlement was not possible. On November 26, 2014, the Chief Judge issued an order terminating the settlement proceeding, designating a presiding judge at the hearings and directing that an initial decision be issued by November 25, 2015.

On December 8, 2014, various state agencies in Delaware, Maryland, New Jersey, and D.C. filed a second complaint against BGE regarding the base ROE of the transmission business seeking a reduction from 10.8% to 8.8%. The filing of the second complaint creates a second refund window. By order issued on February 9, 2015, FERC established a hearing on the second complaint with the complainants' requested refund effective date of December 8, 2014.

Based on the current status of the complaint filings, BGE believes it is probable that BGE's base ROE rate will be adjusted, and that a refund to customers of transmission revenue for the two maximum fifteen month periods will be required. However, BGE is unable

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to estimate the most likely refund amount for either complaint at this time, and has therefore established a reserve, which is not material, representing the low end of a reasonably possible estimated range of loss. Additionally, management is unable to estimate the maximum exposure of a potential refund at this time, which may have a material impact on BGE's results of operations and cash flows. The estimated annual ongoing reduction in revenues if FERC approved the ROEs requested by the parties in their filings is approximately $11 million. If FERC were to order a reduction of BGE's base ROE to 8.7% as sought in the first complaint (while retaining the 50 basis points of any incentives that were credited to the base return on equity for certain new transmission investment), the result of the first fifteen month refund window would be a refund to customers of approximately $13 million. If FERC were to order a reduction in BGE's base ROE to 8.8% as sought in the second complaint (while retaining 50 basis points of any incentives that were credited to the base return on equity for certain new transmission investment) and the refund period extended for a full fifteen months, the result would be a refund to customers of approximately $14 million.

***PJM Transmission Rate Design and Operating Agreements.*** 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 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. On June 25, 2014, the U.S. Court of Appeals for the Seventh Circuit issued a decision once again remanding to FERC the cost allocation of new facilities 500 kV and above. On December 18, 2014, FERC issued an order setting an evidentiary hearing and settlement proceeding regarding the issue of the cost allocation for facilities 500 kV and above. The hearing only concerns new facilities approved by the PJM Board prior to February 1, 2013. ComEd anticipates that all impacts of any rate design changes effective after December 31, 2006, should be recoverable through retail rates and, thus, the rate design changes are not expected to have a material impact on ComEd's 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 any rate design changes are retroactive to periods prior to January 1, 2011, there may be an impact on PECO's results of operations. BGE anticipates that all impacts of any rate design changes effective after the implementation of its standard offer service programs in Maryland should be recoverable through retail rates and, thus, the rate design changes are not expected to have a material impact on BGE's results of operations, cash flows or financial position.

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 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 | 2015 | 2016 | 2017 | 2018 | 2019 |
|---|---|---|---|---|---|---|
| ComEd | $335 | $150 | $172 | $ 5 | $ 4 | $ 4 |
| PECO | 100 | 32 | 31 | 25 | 8 | 4 |
| BGE | 351 | 77 | 104 | 77 | 57 | 36 |

***PJM Minimum Offer Price Rule.*** 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 FERC orders approving the MOPR were upheld by the United States Court of Appeals for the Third Circuit in February 2014.

Exelon continues to work with PJM stakeholders and through the FERC process to implement several proposed changes to the PJM tariff aimed at ensuring that capacity resources (including those with state-sanctioned subsidy contracts and capacity market speculators) cannot inappropriately affect capacity auction prices in PJM.

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***Demand Response Resource Order.*** On May 23, 2014, the D.C. Circuit Court issued an opinion vacating the FERC Order No. 745 ("D.C. Circuit Decision"). Order No. 745 established uniform compensation levels for demand response resources that participate in the day ahead and real-time wholesale energy markets. Under Order No. 745, buyers in ISO and RTO markets were required to pay demand response resources the full Locational Marginal Price when the demand response replaced a generation resource and was cost-effective.

In addition to invalidating the compensation structure established by Order No. 745, the D.C. Circuit Court, in broad language, explained that demand response is part of the retail market and FERC is restricted from regulating retail markets. The full implication of the D.C. Circuit Decision for both energy and capacity markets regulated by FERC is not yet known and will depend on how FERC and the RTOs and ISOs implement the decision. FERC and several other parties sought rehearing of the D.C. Circuit Decision, which was denied in September 2014. In addition, on September 22, 2014, FERC and another party sought to stay the issuance of the D.C. Circuit Court's mandate so that FERC may appeal the decision to the U.S. Supreme Court. The stay was granted with respect to the FERC's request only. In January 2015, the FERC sought to appeal the decision to the U.S. Supreme Court. Thus, the stay will be extended at least until the U.S. Supreme Court determines whether to allow the appeal. In addition, contemporaneously with the D.C. Circuit Court's decision on May 23, 2014, First Energy filed a complaint at FERC asking FERC to direct PJM to remove all PJM Tariff provisions that allow or require PJM to compensate demand response providers as a form of supply in the PJM capacity market effective May 23, 2014. FirstEnergy also asked FERC to declare the results of PJM's May 2014 Base Residual Auction for the 2017/2018 Delivery Year, void and illegal to the extent that demand response resources cleared that auction. On November 14, 2014, the New England Power Generators Association, Inc. ("NEPGA") filed a similar complaint at FERC asking FERC to disqualify demand response from the upcoming capacity auction in New England and to revise the New England tariff to remove demand response from participation in the capacity market. FERC's response to the FirstEnergy complaint and the NEPGA complaint and its response to address the D.C. Circuit Court's decision in all markets could preclude demand response resources from receiving any future capacity market revenues and also subject such resources to refund obligations. In addition, there is uncertainty as to how FERC might treat already settled capacity market auctions as well as future auctions, both for demand response resources and generation resources. FERC could grant all or a portion of the relief requested by FirstEnergy and may grant relief retroactively or only prospectively. FERC could also pursue alternative means for allowing demand response to effectively participate in capacity markets it regulates. Due to these uncertainties, the Registrants are unable to predict the outcome of these proceedings, and the final outcome is not expected for several months. Nonetheless, the final decision and its implementation by FERC and the RTOs and ISOs, could be material to Exelon, Generation, ComEd, PECO and BGE's results of operations and cash flows.

***Market-Based Rates.*** 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. On June 29, 2012, Generation, ComEd, PECO and BGE filed their updated market power analysis for the Central Region which the FERC accepted on November 13, 2012. On December 21, 2012, Generation, ComEd, PECO, and BGE filed their updated market power analysis for the SPP region, which the FERC accepted on October 8, 2013. On December 30, 2013, Generation, ComEd, PECO and BGE filed its updated analysis for the Northeast Region, based on 2012 historic test period data which the FERC accepted on August 5, 2014. On December 23, 2014, Generation filed its updated market power analysis for the Southeast Region and the FERC has not yet acted on the filing.

***Reliability Pricing Model.*** 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, 2018 occurred in May 2014.

***New England Capacity Market Results.*** Each year, ISO New England, Inc. (ISO-NE) files the results of its annual capacity auction at the FERC which is required to include documentation regarding the competitiveness of the auction. Consistent with this

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requirement, on February 28, 2014, ISO-NE filed the results of its eighth capacity auction (covering the June 1, 2017 through May 30, 2018 delivery period). On June 27, 2014, the FERC issued a letter to ISO-NE noting that ISO-NE's February 28, 2014 filing was deficient and that ISO-NE must file additional information before the FERC can process the filing. ISO-NE filed the information on July 17, 2014, and the ISO-NE's filings became effective by operation of law pursuant to a notice issued by the FERC's secretary on September 16, 2014. Several parties sought rehearing of the secretary's notice which was effectively denied in October 2014 and have since appealed the matter to the U.S. D.C. Circuit Court of Appeals. It is not clear whether such appeal would be effective as there is no action by the Commission to be considered. Nonetheless, while we think any change in the auction results to be unlikely, Exelon and Generation cannot predict with certainty what further action the court may take concerning the results of that auction, but any court action could be material to Exelon's and Generation's expected revenues from the capacity auction.

***License Renewals.*** 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") recognized 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. On August 26, 2014, the NRC Commissioners approved the issuance of a revised rule codifying the NRC's generic determinations regarding the environmental impacts of continued storage of spent nuclear fuel beyond a reactor's licensed operating life and removed the hold on final licensing decision as of the effective date of the final rule. On September 19, 2014, the NRC issued the Continued Storage Rule, which became effective on October 20, 2014. On October 24, 2014, New York, Vermont, and Connecticut filed a petition for review in federal court which alleges that the Continued Storage Rule violates various federal laws and regulations. The petition additionally challenges the Continued Storage Rule's supporting generic environmental impact statement (GEIS) as well as the August 26, 2014 NRC order lifting the suspension of all final licensing decisions for affected applications in view of the rule and GEIS.

On May 29, 2013, Generation submitted applications to the NRC to extend the current operating licenses of Byron Units 1 and 2, which are currently set to expire in 2024 and 2026, respectively, and Braidwood Units 1 and 2, currently set to expire in 2026 and 2027, respectively, by 20 years. Generation does not expect the NRC to issue license renewals for Byron and Braidwood until late 2015 at the earliest.

On October 20, 2014, the NRC approved Generation's request to extend the operating licenses of Limerick Units 1 and 2 by 20 years to 2044 and 2049, respectively.

On December 9, 2014, Generation submitted applications to the NRC to extend the operating licenses of LaSalle Units 1 and 2 by 20 years, which are currently set to expire in 2022 and 2023, respectively. Generation does not expect the NRC to issue license renewals for LaSalle until 2016 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.

Generation is working with stakeholders to resolve water quality licensing issues with the MDE for Conowingo, including: (1) water quality, (2) fish passage and habitat, and (3) sediment. On January 30, 2014, Generation 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. MDE indicated that it believed it did not have sufficient information to process Generation's application. As a result, on December 5, 2014, Generation withdrew its pending application for a water quality certification. FERC policy requires that an applicant resubmit its request for a water quality certification within 90 days of the date of withdrawal. Accordingly, Generation is working with MDE to coordinate the refiling of its application for certification within the 90-day period. In addition, Generation has entered into an agreement with MDE to work with state agencies in Maryland, the U.S. Army Corps of Engineers, the U.S. Geological Survey, the University of Maryland Center for Environmental Science and the U.S. Environmental Protection Agency Chesapeake Bay Program to design, conduct and fund an additional multi-year sediment study. Exelon has agreed to contribute up to $3.5 million to fund the additional study. Resolution of these issues relating to Conowingo may have a material effect on Exelon's and Generation's results of operations and financial position through an increase in capital expenditures and operating costs.

**Combined Notes to Consolidated Financial Statements—(Continued)**
**(Dollars in millions, except per share data unless otherwise noted)**

On June 3, 2014, subsequently amended December 9, 2014, the PA DEP issued its water quality certificate for Muddy Run, which is a necessary step in the FERC licensing process and included certain commitments made by Generation. The financial impact associated with these commitments is estimated to be in the range of $25 million to $35 million, and will include both capital expenditures and operating expenses, primarily relating to fish passage and habitat improvement projects.

The FERC licenses for Muddy Run and Conowingo were set to expire on August 31, 2014 and September 1, 2014 respectively. FERC is required to issue annual licenses for the facilities until the new licenses are issued. On September 10, 2014, FERC issued annual licenses for Conowingo and Muddy Run, effective as of the expiration of the previous licenses. If FERC does not issue new licenses prior to the expiration of annual licenses, the annual licenses will renew automatically. The stations are currently being depreciated over their estimated useful lives, which includes the license renewal period. As of December 31, 2014, $39 million of direct costs associated with licensing efforts have been capitalized.

### Regulatory Assets and Liabilities

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.

The following tables provide information about the regulatory assets and liabilities of Exelon as of December 31, 2014 and 2013.

| | December 31, 2014 | |
|---|---|---|
| | Current | Noncurrent |
| **Regulatory assets** | | |
| Pension and other postretirement benefits | $247 | $3,009 |
| Deferred income taxes | 6 | 1,536 |
| AMI programs | 25 | 271 |
| Under-recovered distribution service costs | 251 | 120 |
| Debt costs | 8 | 49 |
| Fair value of BGE long-term debt | 7 | 183 |
| Severance | 4 | 8 |
| Asset retirement obligations | 1 | 115 |
| MGP remediation costs | 36 | 221 |
| Under-recovered uncollectible accounts | — | 67 |
| Renewable energy | 20 | 187 |
| Energy and transmission programs | 37 | 11 |
| Deferred storm costs | 1 | 2 |
| Electric generation-related regulatory asset | 10 | 20 |
| Rate stabilization deferral | 75 | 85 |
| Energy efficiency and demand response programs | 89 | 159 |
| Merger integration costs | 2 | 6 |
| Conservation voltage reduction | 1 | 1 |
| Under-recovered electric revenue decoupling | 7 | — |
| Other [(a)] | 20 | 26 |
| Total regulatory assets | $847 | $6,076 |

**Combined Notes to Consolidated Financial Statements—(Continued)**
**(Dollars in millions, except per share data unless otherwise noted)**

| | December 31, 2014 | |
|---|---|---|
| | Current | Noncurrent |
| **Regulatory liabilities** | | |
| Other postretirement benefits | $ 51 | $ 37 |
| Nuclear decommissioning | — | 2,879 |
| Removal costs | 118 | 1,448 |
| Energy efficiency and demand response programs | 25 | 2 |
| DLC program costs | — | 10 |
| Energy efficiency phase II | — | 32 |
| Electric distribution tax repairs | 8 | 94 |
| Gas distribution tax repairs | 20 | 29 |
| Energy and transmission programs | 68 | 16 |
| Over-recovered electric universal service fund costs | 2 | — |
| Revenue subject to refund | 3 | — |
| Over-recovered gas revenue decoupling | 12 | — |
| Other | 3 | 3 |
| Total regulatory liabilities | $310 | $4,550 |

| | December 31, 2013 | |
|---|---|---|
| | Current | Noncurrent |
| **Regulatory assets** | | |
| Pension and other postretirement benefits | $221 | $2,794 |
| Deferred income taxes | 10 | 1,459 |
| AMI programs | 5 | 159 |
| AMI meter events | — | 5 |
| Under-recovered distribution service costs | 178 | 285 |
| Debt costs | 12 | 56 |
| Fair value of BGE long-term debt | — | 219 |
| Fair value of BGE supply contracts | 12 | — |
| Severance | 16 | 12 |
| Asset retirement obligations | 1 | 102 |
| MGP remediation costs | 40 | 212 |
| RTO start-up costs | 2 | — |
| Under-recovered uncollectible accounts | — | 48 |
| Renewable energy | 17 | 176 |
| Energy and transmission programs | 53 | 9 |
| Deferred storm costs | 3 | 3 |
| Electric generation-related regulatory asset | 13 | 30 |
| Rate stabilization deferral | 71 | 154 |
| Energy efficiency and demand response programs | 73 | 148 |
| Merger integration costs | 2 | 9 |
| Other [a] | 31 | 30 |
| Total regulatory assets | $760 | $5,910 |

**Combined Notes to Consolidated Financial Statements—(Continued)**
**(Dollars in millions, except per share data unless otherwise noted)**

| | December 31, 2013 | |
|---|---|---|
| | Current | Noncurrent |
| **Regulatory liabilities** | | |
| Other postretirement benefits | $ 2 | $ 43 |
| Nuclear decommissioning | — | 2,740 |
| Removal costs | 99 | 1,423 |
| Energy efficiency and demand response programs | 53 | — |
| DLC Program Costs | 1 | 10 |
| Energy efficiency phase II | — | 21 |
| Electric distribution tax repairs | 20 | 114 |
| Gas distribution tax repairs | 8 | 37 |
| Energy and transmission programs | 78 | — |
| Over-recovered gas universal service fund costs | 8 | — |
| Revenue subject to refund | 38 | — |
| Over-recovered electric and gas revenue decoupling | 16 | — |
| Other | 4 | — |
| Total regulatory liabilities | $327 | $4,388 |

***Pension and other postretirement benefits.*** As of December 31, 2014, Exelon had regulatory assets of $3,256 million and regulatory liabilities of $88 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 Constellation 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 Constellation 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 was 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. For PECO, this amount includes the impacts of electric and gas distribution repairs in the deductibility pursuant to PUC's 2010 rate case settlement agreement. 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 through May 31, 2014, and January 1, 2020, respectively. As of December 31, 2014 and December 31, 2013, ComEd had regulatory assets of $88 million and $35 million, respectively, 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 regulatory asset. 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 recovery of those costs commenced with the new rates approved and implemented with the MDPSC order in BGE's 2014 electric and gas distribution case.

***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 not 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 deferred these costs on Exelon's Consolidated Balance Sheet, beginning in 2012. PECO did not earn a return on the recovery of these costs. Pursuant to the January 23, 2014, vendor agreement, PECO reclassified the regulatory asset balance as a receivable, which has been fully collected, with no gain or loss impacts on future results of operations.

***Under-recovered distribution services costs.*** Under EIMA, 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 was recovered through rates over a one-year period that began in January 2014. The under recovery associated with the 2013 reconciliation will be recovered through rates over a one-year period beginning in January 2015. 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, 2014, the regulatory asset was comprised of $286 million for the applicable annual reconciliations and $85 million related to significant one-time events. In addition to $66 million in deferred storm costs, net of amortization, the December 31, 2014 balance related to significant one-time events contains $19 million of Constellation merger and integration related costs, net of amortization, incurred as a result of the Constellation merger. As of December 31, 2013, the regulatory asset was comprised of $377 million for the applicable annual reconciliations 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 Constellation merger and integration related costs, net of amortization, incurred as a result of the Constellation merger. See Note 4—Mergers, Acquisitions, and Dispositions 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.

**Combined Notes to Consolidated Financial Statements—(Continued)**
**(Dollars in millions, except per share data unless otherwise noted)**

***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 Constellation 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 and is not earning a return on the recovery of these costs.

***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 Constellation merger date based on the MDPSC practice to allow BGE to recover its supply contracts through rates. Exelon amortized the regulatory asset and the associated fair value through December 31, 2014 and was not earning a return on the recovery of these contracts.

***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, and such costs were fully recovered as of December 31, 2014. ComEd did not earn 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 through December 31, 2013. 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***. ComEd is allowed recovery of these costs under ICC approved rates. For PECO, these costs are recoverable through rates as affirmed in the 2010 approved natural gas distribution rate case settlement. 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. 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. 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, 2014, PECO was under-recovered for its gas program and over-recovered for its electric program. Whereas, 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.

***Under (Over)-recovered uncollectible accounts.*** ComEd adjusts its rates annually to reflect the increases and decreases in annual uncollectible accounts costs. The recovery or refund of the difference in the uncollectible accounts costs takes 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.

***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

**Combined Notes to Consolidated Financial Statements—(Continued)**
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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.*** 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. As of December 31, 2014, ComEd's regulatory asset of $33 million included $4 million related to under-recovered energy costs for non-hourly customers, $22 million associated with transmission costs recoverable through its FERC-approved formulate rate, and $7 million of Constellation merger and integration costs to be recovered upon FERC approval. As of December 31, 2014, ComEd's regulatory liability of $19 million included $3 million related to over-recovered energy costs for hourly customers and $16 million associated with revenues received for renewable energy requirements. As of December 31, 2013, ComEd's regulatory asset of $58 million included $35 million related to under-recovered energy costs for hourly and non-hourly customers, $17 million associated with transmission costs recoverable through its FERC-approved formula rate, and $6 million of Constellation merger and integration costs to be recovered upon FERC approval. As of December 31, 2013, ComEd's regulatory liability of $9 million related to revenues received for renewable energy requirements.

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. See discussion below of each program. 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, 2014, PECO had a regulatory liability that included $39 million related to the DSP program, $16 million related to over-recovered natural gas supply costs under the PGC and $3 million related to over-recovered electric transmission costs. As of December 31, 2013, PECO had a regulatory liability that included $34 million related to the DSP program, $8 million related the over-recovered electric transmission costs and $16 million related to over-recovered natural gas supply costs under the PGC.

*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. 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. These costs are included within the energy and transmission programs line item.

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, 2014, BGE's regulatory asset of $15 million included $10 million related to under-recovered electric energy costs, $4 million of Constellation merger and integration costs and $1 million of abandonment costs to be recovered upon FERC approval. As of December 31, 2014, BGE's regulatory liability of $7 million related to over-recovered natural gas supply costs. As of December 31, 2013, BGE's regulatory asset of $4 million included $3 million of Constellation merger and integration costs and $1 million of abandonment costs to be recovered upon FERC approval. As of December 31, 2013, BGE's regulatory liability of $11 million related to over-recovered natural gas supply costs.

***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.

**Combined Notes to Consolidated Financial Statements—(Continued)**
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***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 was $28 million as of December 31, 2014, and $37 million as of December 31, 2013. 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 2014 and 2013, BGE recovered $65 million and $66 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 recovers these costs 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℠ 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 Constellation 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, 2014, BGE had a regulatory asset of $7 million related to under-recovered electric revenue decoupling and a regulatory liability of $12 million related to over-recovered natural gas revenue decoupling. 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.

**Combined Notes to Consolidated Financial Statements—(Continued)**
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***Nuclear decommissioning.*** These amounts represent estimated future nuclear decommissioning costs for the Regulatory Agreement Units 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 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. These costs are included within the energy and transmission programs line item.

***Revenue subject to refund.*** These amounts represent refunds and associated interest ComEd owes to customers primarily related to the treatment of the post-test year accumulated depreciation issue in the 2007 Rate Case. As of December 31, 2014, and December 31, 2013, ComEd owed $3 million and $37 million with $1 million of interest, respectively. See above discussion of the 2007 Rate Case for further information.

**Purchase of Receivables Programs**

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, Consolidated Balance Sheets. The following table provides information about the purchased receivables of Exelon as of December 31, 2014 and 2013.

| | As of December 31, | |
|---|---|---|
| | 2014 | 2013 |
| Purchased receivables [(a)] | $290 | $263 |
| Allowance for uncollectible accounts [(b)] | (42) | (30) |
| Purchased receivables, net | $248 | $233 |

**Combined Notes to Consolidated Financial Statements—(Continued)**
**(Dollars in millions, except per share data unless otherwise noted)**

(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. Mergers, Acquisitions, and Dispositions

### Proposed Merger with Pepco Holdings, Inc.

***Description of Transaction***

On April 29, 2014, Exelon and Pepco Holdings, Inc. (PHI) signed an agreement and plan of merger (as subsequently amended and restated as of July 18, 2014, the Merger Agreement) to combine the two companies in an all cash transaction. The resulting company will retain the Exelon name and be headquartered in Chicago. Under the Merger Agreement, PHI's shareholders will receive $27.25 of cash in exchange for each share of PHI common stock. In connection with the Merger Agreement, Exelon entered into a subscription agreement under which it has purchased $126 million of a new class of nonvoting, nonconvertible and nontransferable preferred securities of PHI as of December 31, 2014, with additional investments of $18 million to be made quarterly up to a maximum aggregate investment of $180 million. The preferred securities are included in Other non-current assets on Exelon's Consolidated Balance Sheet. PHI has the right to redeem the preferred securities at its option for the purchase price paid plus accrued dividends, if any. Exelon expects total cash required to fund the acquisition of common stock and preferred securities plus other related acquisition costs to total approximately $7.2 billion. As part of the applications for approval of the merger, Exelon and PHI proposed a package of benefits to the PHI utilities' respective customers, providing for direct investment of more than $100 million with the actual amount and timing of any related payments dependent upon settlement discussions in merger regulatory approval proceedings and the terms of regulatory orders approving the merger.

To date, the PHI stockholders, the Virginia State Corporation Commission, the New Jersey Board of Public Utilities (NJBPU) and the FERC have approved the merger of PHI and Exelon. The Federal Communications Commission has also approved the transfer of certain PHI communications licenses. On February 11, 2015, the NJBPU approved the proposed merger and the previously filed settlement signed and filed by Exelon, PHI, Atlantic City Electric (ACE), NJBPU staff, and the Independent Energy Coalition. The settlement provides a package of benefits to ACE customers and the state of New Jersey. This package of benefits includes the establishment of customer rate credit programs, with an aggregate value of $62 million for ACE customers and energy efficiency programs that will provide savings for ACE customers of $15 million.

Completion of the transaction also remains conditioned upon approval by the Public Services Commissions of the District of Columbia, Delaware and Maryland. Procedural schedules have been set in these commission proceedings and final approval decisions are expected in the first half of 2015.

On October 9, 2014, PHI and Exelon each received a request for additional information from the DOJ. The request had the effect of extending the DOJ review period until 30 days after PHI and Exelon each has certified that it had substantially complied with the request. On November 21, 2014, Exelon and PHI each certified that it had substantially complied with the request. Accordingly, the HSR Act waiting period expired on December 22, 2014, and the HSR Act no longer precludes completion of the merger. Although the DOJ allowed the waiting period under the HSR Act to expire without taking any action with respect to the merger, the DOJ has not advised Exelon or PHI that it has concluded its investigation. Exelon and PHI will continue to work cooperatively with the DOJ regarding the proposed merger.

Exelon and PHI continue to expect to complete the merger in the second or third quarter of 2015.

Exelon has been named in suits filed in the Delaware Chancery Court alleging that individual directors of PHI breached their fiduciary duties by entering into the proposed merger transaction and Exelon aided and abetted the individual directors' breaches. The suits seek to enjoin PHI from completing the merger or seek rescission of the merger if completed. In addition, they also seek unspecified damages and costs. In September 2014, the parties reached a proposed settlement which is subject to court approval. Final court approval of the proposed settlement is not expected to occur until the second quarter of 2015, at the earliest. Exelon has also been named in a federal court case with similar claims and is in the process of negotiating a settlement. Exelon does not believe these suits will impact the completion of the transaction, and they are not expected to have a material impact on Exelon's results of operations.

Through December 31, 2014, Exelon has incurred approximately $179 million of expense associated with the proposed merger, primarily $48 million related to acquisition and integration costs and $131 million of costs incurred to finance the transaction. The Merger Agreement also provides for termination rights on behalf of both parties. Under certain circumstances, if the Merger Agreement is terminated, PHI may be required to pay Exelon a termination fee ranging from $259 million to $293 million plus certain expenses. If the Merger Agreement does not close due to a regulatory failure, Exelon may be required to pay PHI a termination fee equal to the amount of purchased nonvoting preferred securities of PHI described above, through the redemption by PHI of the outstanding nonvoting preferred securities for no consideration other than the nominal par value of the stock.

***Merger Financing***

Exelon intends to fund the all-cash transaction using a combination of approximately $3.5 billion of debt, up to $1.0 billion in cash from asset sales primarily at Generation, and the remainder through issuance of equity (including mandatory convertible securities). On June 11, 2014, Exelon marketed an equity offering of 57.5 million shares of its common stock at a public offering price of $35 per share in connection with forward sales agreements and $1.2 billion of junior subordinated notes in the form of 23 million equity units. In addition, Exelon signed a 364-day $7.2 billion senior unsecured bridge credit facility to support the contemplated transaction and provide flexibility for timing of permanent financing, which has subsequently been reduced to a $3.2 billion facility as a result of the execution of the debt and equity security issuances and the net after-tax cash proceeds from generating asset divestitures during the second half of 2014. See Note 13—Debt and Credit Agreements and Note 19—Common Stock for more information.

**Acquisitions**

***Acquisition of Integrys Energy Services, Inc.***

On November 1, 2014, Generation acquired the competitive retail electric and natural gas business activities of Integrys Energy Group, Inc. through the purchase of all of the stock of its wholly owned subsidiary, Integrys Energy Services, Inc. (Integrys) for a purchase price of $332 million, including net working capital. Generation has elected to account for the transaction as an asset acquisition for federal income tax purposes. As of December 31, 2014, Generation had remitted $319 million to Integrys Energy Group, Inc. and the remaining balance of $13 million, which is included in Other current liabilities on Exelon's Consolidated Balance Sheets, will be paid during the first or second quarter of 2015. The generation and solar asset businesses of Integrys are excluded from the transaction. The Purchase Agreement also includes various representations, warranties, covenants, indemnification and other provisions customary for a transaction of this nature.

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.

**Combined Notes to Consolidated Financial Statements—(Continued)**
**(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 the Integrys acquisition by Generation:

| | |
|---|---|
| Total consideration transferred | $ 332 |
| **Identifiable assets acquired and liabilities assumed** | |
| Working capital assets | $ 389 |
| Mark-to-market derivative assets | 185 |
| Unamortized energy contract assets | 115 |
| Customer relationships | 48 |
| Working capital liabilities | (195) |
| Mark-to-market derivative liabilities | (57) |
| Unamortized energy contract liabilities | (109) |
| Deferred tax liability | (16) |
| Total net identifiable assets, at fair value | $ 360 |
| Bargain purchase gain (after-tax) | $ 28 |

The purchase accounting is preliminary, and although not expected, may be further adjusted from what is shown above.

The after-tax bargain purchase gain of $28 million is primarily the result of IES executing additional contract volumes between the date the acquisition agreement was signed and the closing of the transaction resulting in an increase in the fair value of the net assets acquired as of the acquisition date. The after-tax gain is included within Gain on consolidation and acquisition of businesses in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income.

IES's operating revenue and net loss included in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income for the period from November 1, 2014 to December 31, 2014 were approximately $386 million and $(42) million, respectively. The net loss includes pre-tax unrealized losses on derivative contracts of $108 million and the bargain purchase gain of $28 million. Exelon and Generation incurred approximately $7 million of merger and integration related costs which are included within Operating and maintenance expense in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income.

**Merger with Constellation**

***Description of Constellation Merger 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.

***Regulatory Matters from the Constellation Merger***

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.

**Combined Notes to Consolidated Financial Statements—(Continued)**
**(Dollars in millions, except per share data unless otherwise noted)**

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 | Exelon | Statement of Operations Location |
|---|---|---|---|
| BGE rate credit of $100 per residential customer [a] | Q2 2012 | $113 | Revenues |
| Customer investment fund to invest in energy efficiency and low-income energy assistance to BGE customers | 2012 to 2014 | 114 | 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 | 70 | O&M Expense |
| State funding for offshore wind development projects | Q2 2012 | 32 | O&M Expense |
| Miscellaneous tax benefits | Q2 2012 | (2) | Taxes Other Than Income |
| Total | | $329 | |

(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 was contingent upon the developer obtaining all required approvals, permits and financing for the construction of a building in Baltimore, Maryland. The operating lease became effective during the second quarter of 2014 when these outstanding contingencies were met by the developer. See Note 22—Commitments and Contingencies for further information regarding Generation's total commitments under the lease agreement.

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—300MWs 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 or certain specified provisions are elected, 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. However, during the third quarter of 2014, the conditions associated with one of the generation development commitments changed such that Exelon and Generation now believe that the most likely outcome will involve making subsidy payments and/or liquidated damages payments rather than constructing the specified generating plant. As a result, Exelon and Generation recorded a pre-tax $44 million loss contingency related to this generation development commitment which is included in Operating and maintenance expense in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income. While this $44 million loss contingency represents Generation's best estimate of the future obligation, it is reasonably possible that Exelon and Generation could ultimately be required to make cumulative subsidy payments of up to a maximum of approximately $105 million over a 20-year period dependent on actual generating output from a successfully constructed generating plant.

To date, Generation has placed into service 40MW and has commenced development of 150MW of new generation in Maryland towards the 300MW commitment. In July 2013, Generation executed an engineering procurement and construction contract to expand its Perryman, Maryland site with at least 120MW of natural gas-fired generation to satisfy one of the commitments to Maryland with achievement of commercial operation expected in 2015. In December 2013, Generation entered into contracts associated with the construction of the 40MW Fourmile Wind project, which was placed in service in December 2014. In December 2014, Generation entered into contracts associated with the construction of the 30MW Fair Wind project in western Maryland with achievement of commercial operations expected in 2015. The wind projects will satisfy a portion of the 125MW Tier I land-based renewables commitment. See Note 22—Commitments and Contingencies for additional information. Exelon's and Generation's consolidated financial statements include $185 million and $24 million of capitalized expenditures within Property, plant and equipment, net as of December 31, 2014 and 2013, respectively, and $3 million and $6 million of development costs within Operating and maintenance expense for the periods ended December 31, 2014 and 2013, respectively, associated with the pursuit of these commitments for new generation in the State of Maryland.

**Combined Notes to Consolidated Financial Statements—(Continued)**
**(Dollars in millions, except per share data unless otherwise noted)**

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 was 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 was 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 Constellation Merger***

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 ratesetting 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.

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

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.

The final purchase price allocation of the Merger of Exelon with Constellation was as follows:

| Preliminary Purchase Price Allocation, excluding amortization | Exelon |
|---|---|
| Current assets | $ 4,936 |
| Property, plant, and equipment | 9,342 |
| Unamortized energy contracts | 3,218 |
| Other intangibles, trade name and retail relationships | 457 |
| Investment in affiliates | 1,942 |
| Pension and OPEB regulatory asset | 740 |
| Other assets | 2,265 |
| Total assets | 22,900 |
| Current liabilities | 3,408 |
| Unamortized energy contracts | 1,722 |
| Long-term debt, including current maturities | 5,632 |
| Noncontrolling interest | 90 |
| Deferred credits and other liabilities and preferred securities | 4,683 |
| Total liabilities, preferred securities and noncontrolling interest | 15,535 |
| Total purchase price | $ 7,365 |

***Impact of the Constellation 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 $3,165 million, $3,065 million and $2,091 million and net income (loss) $211 million, $210 million and $(31) million during the years ended December 31, 2014, 2013 and 2012, respectively.

During the year ended December 31, 2014, Exelon and Generation both incurred merger and integration-related costs of $22 million. Of these amounts, nothing was deferred as a regulatory asset as of December 31, 2014.

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.

**Combined Notes to Consolidated Financial Statements—(Continued)**
**(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, 2014, 2013, and 2012. See Note 22—Commitments and Contingencies for additional information.

***Pro-forma Impact of the Constellation Merger***

The following unaudited pro forma financial information reflects the consolidated results of operations of Exelon as if the merger with Constellation had taken place on January 1, 2011. The unaudited pro forma information was calculated after applying Exelon'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.

| | Exelon | |
|---|---|---|
| | Year Ended December 31, | |
| **(unaudited)** | **2012** | **2011 (a)** |
| Total revenues | 26,700 | 30,712 |
| Net income attributable to Exelon | 2,092 | 974 |
| Basic earnings per share | 2.56 | 1.15 |
| Diluted earnings per share | 2.55 | 1.14 |

(a) The amounts above include non-recurring costs directly related to the merger of $236 million for the year ended December 31, 2011.
(b) The amounts above include non-recurring costs directly related to the merger of $203 million for the year ended December 31, 2011.

**Asset Divestitures**

Including the Quail Run generating facility that was sold on January 21, 2015, Generation has sold certain generating assets with a total net book value of approximately $1.8 billion prior to consideration of asset impairments (See Note 8—Impairment of Long-Lived Assets for further information), for total pre-tax proceeds of approximately $1.8 billion (after-tax proceeds of approximately $1.4 billion), which resulted in cumulative pre-tax gains on sale of approximately $412 million, which are included in Gain (loss) on sales of assets on Exelon's Consolidated Statement of Operations and Comprehensive Income. The proceeds are expected to be used primarily to finance a portion of the acquisition of PHI.

| Station | Net Generation Capacity | Location | Operating Segment | Percent Owned |
|---|---|---|---|---|
| Fore River | 726 MW | North Weymouth, MA | New England | 100% |
| West Valley | 185 MW | Salt Lake City, UT | Other | 100% |
| Keystone | 714 MW | Shelocta, PA | Mid-Atlantic | 41.98% |
| Conemaugh | 532 MW | New Florence, PA | Mid-Atlantic | 31.28% |
| Safe Harbor | 278 MW | Conestoga, PA | Mid-Atlantic | 66.7% |
| Quail Run | 488 MW | Odessa, TX | ERCOT | 100% |

**Combined Notes to Consolidated Financial Statements—(Continued)**
**(Dollars in millions, except per share data unless otherwise noted)**

At December 31, 2014, the assets and liabilities of the Quail Run generating facility were reported as Assets held for sale and within Other current liabilities on Exelon's Consolidated Balance Sheets. The table below presents the major classes of assets and liabilities held for sale at December 31, 2014.

| | December 31, 2014 |
|---|---|
| **Assets:** | |
| Property, plant and equipment, net [(a)] | $143 |
| Inventory | 4 |
| Total assets held for sale | $147 |
| **Liabilities:** | |
| Accrued expenses | $ 1 |
| Asset retirement obligations | 4 |
| Total liabilities held for sale [(b)] | $ 5 |

(a) The total aggregate book value of property, plant and equipment is net of a $50 million pre-tax impairment loss recorded within Operating and maintenance expense on Exelon's and Generation's Statements of Operations and Comprehensive Income. See Note 8—Impairment of Long-Lived Assets for further information.
(b) Included within Other current liabilities on Exelon's Consolidated Balance Sheets.

**5. Investment in Constellation Energy Nuclear Group, LLC**

As a result of the Constellation merger, Generation owns a 50.01% interest in CENG, a nuclear generation business. Generation has historically had 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 April 1, 2014, Generation and subsidiaries of Generation, EDF, EDF, Inc. (EDFI) (a subsidiary of EDF) and CENG entered into 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 (the Integration Transaction). CENG will reimburse Generation for its direct and allocated costs for such services. As part of the arrangement, Nine Mile Point Nuclear Station, LLC, a subsidiary of CENG, also assigned to Generation its obligations as Operator of Nine Mile Point Unit 2 under an operating agreement with Long Island Power Authority, the Unit 2 co-owner. In addition, on April 1, 2014, the Power Services Agency Agreement (PSAA) was amended and extended until the permanent cessation of power generation by the CENG generation plants.

In addition, on April 1, 2014, Generation made 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 April 1, 2034, whichever occurs first. Immediately following receipt of the proceeds of such loan, CENG made a $400 million special distribution to EDFI.

Exelon, Generation, and subsidiaries of Generation, EDFI and its parent (E.D.F. International S.A.S.), and CENG also executed a Fourth Amended and Restated Operating Agreement for CENG on April 1, 2014, pursuant to which, among other things, CENG committed to make preferred distributions to Generation (after repayment of the $400 million loan and associated interest) 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 April 1, 2014 (Preferred Distribution Rights).

Generation and EDFI also entered into a Put Option Agreement on April 1, 2014, pursuant to which EDFI has 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 NOSA. In addition, under limited circumstances, the period for exercise of the put option may be extended for 18 months.

On April 1, 2014, Generation also executed an Indemnity Agreement pursuant to which Generation indemnified 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 guarantees Generation's obligations under this indemnity.

In addition, on April 1, 2014, Generation, EDFI, CENG and Nine Mile Point Nuclear Station, LLC entered into an Employee Matters Agreement (EMA) that provides for the transfer of CENG employees to Exelon or one of its affiliates and Exelon's assumption of the sponsorship of the employee benefit plans (including certain incentive, health and welfare, and postemployment benefit plans, among others) and their related trusts by Exelon as the plan sponsor as of July 14, 2014. The EMA also generally requires CENG to fund the obligation related to pre-transfer service of employees, including the underfunded balance of the pension and other postretirement welfare benefit plans measured as of July 14, 2014 by making periodic payments to Generation. These payments will be made on an agreed payment schedule or upon the occurrence of certain specified events, such as EDF's disposition of a majority of its interest in CENG.

As a condition to obtaining regulatory approval for the NOSA and related transactions from the NRC, Exelon executed a support agreement pursuant to which Exelon may be required under specified circumstances to provide up to $245 million of financial support to CENG (Exelon Support Agreement). The Exelon Support Agreement supersedes a previous support agreement under which Generation had agreed to provide up to $205 million of financial support for CENG. In addition, Exelon executed a Guarantee pursuant to which Exelon may be required under specified circumstances to provide up to $165 million in additional financial support for CENG. A previous support agreement executed by an affiliate of EDF remains in effect under which the EDF affiliate may be required to provide up to approximately $145 million of financial support for CENG under specified circumstances. The agreements were executed on April 1, 2014 when the NRC licenses were transferred to Generation. No liability has been recognized by Exelon for the guarantees.

Prior to April 1, 2014, Exelon and Generation accounted for their investment in CENG under the equity method of accounting. From January 1, 2014, through March 31, 2014, Generation recorded $19 million of equity in losses of unconsolidated affiliates related to its investment in CENG and recorded $17 million of revenues from CENG. For the twelve months ended December 31, 2013, Generation recorded $9 million of equity in losses of unconsolidated affiliates related to its investment in CENG and $56 million of revenues from CENG. The book value of Generation's investment in CENG prior to the consolidation was $1.9 billion, and the book value of the AOCI related to CENG prior to consolidation was $116 million, net of taxes of $77 million.

As a result of the consolidation of CENG on April 1, 2014, there are several additional transactions included in Exelon's Consolidated Financial Statements between CENG and EDF that are considered related party transactions to Generation. As further described in Note 25—Related Party Transactions EDF and Generation had a PPA with CENG under which they purchased 15% and 85% (through December 31, 2014), respectively, of the nuclear output owned by CENG that was not sold to third parties under pre-existing PPAs. Beginning January 1, 2015 and continuing through the life of the respective plants, EDF and Generation will purchase 49.99% and 50.01%, respectively, of the nuclear output owned by CENG. Beginning April 1, 2014, sales to Generation are eliminated in consolidation. For the year ended December 31, 2014, Generation had sales to EDF of $137 million. See discussion above and Note 2—Variable Interest Entities for additional information regarding other transactions, between CENG and EDF included within Exelon financial statements.

See Note 2—Variable Interest Entities for additional information about the Registrant's VIEs.

### *Accounting for the Consolidation of CENG*

The transfer of the nuclear operating licenses and the execution of the NOSA on April 1, 2014, resulted in the derecognition of the equity method investment in CENG and the recording of all assets, liabilities and EDF's noncontrolling interest in CENG at fair value on Exelon's Consolidated Balance Sheets. As a result of the consolidation, Exelon recorded a net gain of $261 million within their respective Consolidated Statements of Operations and Comprehensive Income. This gain consists of approximately $136 million related to the step up to fair value basis of our ownership interest in CENG, and approximately $132 million related to the settlement of pre-existing transactions between CENG and Generation. The net gain on the consolidation of CENG of $261 million is net of a $7 million payment to EDF.

**Combined Notes to Consolidated Financial Statements—(Continued)**
**(Dollars in millions, except per share data unless otherwise noted)**

The fair value of CENG's assets and liabilities recorded in consolidation 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 valuations necessary to assess the fair values of certain assets and liabilities are considered preliminary as a result of the short time period between the execution of the NOSA and the end of the second quarter of 2014. The estimates of the fair value of assets and liabilities may be modified up to one year from April 1, 2014, as more information is obtained about the fair value of assets and liabilities. The principal items that have been revised include the asset retirement obligation liabilities and related asset retirement costs. These items have been updated with inputs from a third party engineering firm with corresponding adjustments recorded in 2014. See Note 15—Asset Retirement Obligations for discussion of the impacts of adjustments recorded during 2014 related to updated estimates of the CENG asset retirement obligation liabilities. In the period of such revisions, these and any other material changes to the fair value assessments have resulted in adjustments to the amounts recorded upon consolidation. In addition, the asset or liability adjustments impacting depreciation and/or accretion expense recorded after the consolidation date have impacted Generation's post-consolidation results of operations. No material changes are expected to the fair value of assets and liabilities.

Generation recorded the assets and liabilities of CENG at fair value as of April 1, 2014. The following assets and liabilities of CENG were recorded within Exelon's Consolidated Balance Sheets as of the date of integration, adjusted for the modifications discussed above:

| Fair Values | |
|---|---|
| Current assets | $ 499 |
| Nuclear decommissioning trust fund | 1,955 |
| Property, plant and equipment | 3,017 |
| Nuclear fuel | 482 |
| Other assets | 10 |
| Total assets | 5,963 |
| Current liabilities | 237 |
| Asset retirement obligation | 1,760 |
| Pension and other employee benefit obligations | 281 |
| Unamortized energy contract liabilities | 171 |
| Other liabilities | 114 |
| Total liabilities | 2,563 |
| Total net assets | $3,400 |

Exelon also recorded the fair value of the noncontrolling interest on its Consolidated Balance Sheets of approximately $1.5 billion, net of the fair value of $152 million for certain specified additional distribution rights under the Operating Agreement. In addition, the noncontrolling interest was further reduced by the $400 million special cash distribution to EDF.

Due to the Preferred Distribution Rights that Generation has on CENG's available cash, the earnings attributable to the noncontrolling interest on Exelon's Statements of Operations and Comprehensive Income as well as the corresponding adjustment to Noncontrolling interest on Exelon's Consolidated Balance Sheets will not be in proportion to Generation's and EDF's equity ownership interests. Rather, the attribution will consider Generation's Preferred Distribution Rights and allocate net income based on each owner's rights to CENG'S net assets. For the year ended December 31, 2014, Generation reduced by $13 million the amount of Net income attributable to noncontrolling interests on Exelon's Consolidated Statements of Operations and Comprehensive Income. As a result of the consolidation, Exelon's Consolidated Statements of Operations and Comprehensive Income includes CENG's incremental operating revenues of $218 million and CENG's net income, prior to any intercompany eliminations and any adjustments for noncontrolling interest, of $407 million during the year ended December 31, 2014.

Exelon incurred integration-related costs of $26 million for the year ended December 31, 2014. The costs incurred are classified primarily within Operating and maintenance expense in Exelon's Consolidated Statements of Operations and Comprehensive Income for the year ended December 31, 2014.

**Combined Notes to Consolidated Financial Statements—(Continued)**
**(Dollars in millions, except per share data unless otherwise noted)**

See Note 17—Severance for integration-related severance costs incurred during the year ended December 31, 2014.

### 6. Accounts Receivable

Accounts receivable at December 31, 2014 and 2013 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:

| | |
|---|---|
| **2014** | |
| Unbilled customer revenues | $1,381 |
| Allowance for uncollectible accounts [(a)] | (311) |
| **2013** | |
| Unbilled customer revenues | $1,151 |
| Allowance for uncollectible accounts [(a)] | (272) |

(a) Includes the allowance for uncollectible accounts on customer and other accounts receivable.

***PECO Installment Plan Receivables.*** 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 $15 million and $19 million as of December 31, 2014 and 2013, 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, 2014 of $15 million consists of $1 million, $3 million and $11 million for low risk, medium risk and high risk segments, respectively. The allowance for uncollectible accounts balance 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 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, 2014 and 2013 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.

### 7. Property, Plant and Equipment

The following table presents a summary of property, plant and equipment by asset category as of December 31, 2014 and 2013:

| | Average Service Life (years) | 2014 | 2013 |
|---|---|---|---|
| **Asset Category** | | | |
| Electric—transmission and distribution | 5-90 | $30,157 | $28,123 |
| Electric—generation | 1-56 | 22,911 | 20,420 |
| Gas—transportation and distribution | 5-90 | 3,505 | 3,296 |
| Common—electric and gas | 5-50 | 1,169 | 1,101 |
| Nuclear fuel [(a)] | 1-8 | 5,947 | 5,196 |
| Construction work in progress | N/A | 2,167 | 1,890 |
| Other property, plant and equipment [(b)] | 5-50 | 973 | 1,017 |
| Total property, plant and equipment | | 66,829 | 61,043 |
| Less: accumulated depreciation [(c)] | | 14,742 | 13,713 |
| Property, plant and equipment, net | | $52,087 | $47,330 |

**Combined Notes to Consolidated Financial Statements—(Continued)**
**(Dollars in millions, except per share data unless otherwise noted)**

(a) Includes nuclear fuel that is in the fabrication and installation phase of $1,003 million and $947 million at December 31, 2014 and 2013, respectively.
(b) Includes Generation's buildings under capital lease with a net carrying value of $15 million and $23 million at December 31, 2014 and 2013, respectively. The original cost basis of the buildings was $52 million and $59 million, and total accumulated amortization was $37 million and $36 million, as of December 31, 2014 and 2013, respectively. Also includes ComEd's buildings under capital lease with a net carrying value at both December 31, 2014 and 2013, of $8 million. The original cost basis of the buildings was $8 million and total accumulated amortization was immaterial as of December 31, 2014 and 2013, respectively. Includes land held for future use and non utility property at ComEd, PECO, and BGE of $57 million, $21 million, and $32 million, respectively. These balances also include capitalized acquisition, development and exploration costs of $242 million related to oil and gas production activities at Generation.
(c) Includes accumulated amortization of nuclear fuel in the reactor core at Generation of $2,673 million and $2,371 million as of December 31, 2014 and 2013, respectively.

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 | 2014 | 2013 | 2012 |
|---|---|---|---|
| Electric—transmission and distribution | 2.93% | 2.91% | 2.76% |
| Electric—generation | 3.50% | 3.35% | 3.15% |
| Gas | 2.13% | 2.06% | 2.03% |
| Common—electric and gas | 7.32% | 7.53% | 7.61% |

***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.

See Note 1—Significant Accounting Policies 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

### Long-Lived Assets

Generation evaluates long-lived assets for recoverability whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. In 2014, updates to the long-term fundamental energy prices, which included a thorough evaluation of key assumptions including gas prices, load growth, plant retirements and renewable growth, suggested that the carrying value of certain wind assets with market price exposure may be impaired. Generation concluded that the estimated undiscounted future cash flows and fair value of twelve wind projects, primarily located in West Texas, were less than their respective carrying values at May 31, 2014. As a result, long-lived assets held and used with a carrying amount of approximately $151 million were written down to their fair value of $65 million and a pre-tax impairment charge of $86 million was recorded in Operating and maintenance expense in Exelon's Consolidated Statements of Operations and Comprehensive Income.

In 2013, lower projected wind production and a decline in power prices suggested that the carrying value of certain wind projects with market price exposure for either all or a portion of the life of the asset 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. 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, net of the impairment amount attributable to noncontrolling interests for certain of the projects, was recorded in Operating and maintenance expense in Exelon's Consolidated Statements of Operations and Comprehensive Income.

In 2014, certain non-nuclear generating assets were identified as assets held for sale on Exelon's Consolidated Balance Sheets. When long-lived assets are held for sale, an impairment loss is recognized to the extent that the asset's carrying value exceeds its estimated fair value less costs to sell. Long-lived assets with a carrying amount of approximately $1 billion were written down to their fair value of $556 million and a pre-tax impairment charge of $450 million was recorded in Operating and maintenance expense on Exelon's Consolidated Statements of Operations and Comprehensive Income.

In 2012, a subsidiary of Generation sold three Maryland generating stations in connection with the Constellation merger. As a result of the transaction, Exelon recorded a pre-tax impairment charge of $272 million to reflect the difference between the sales price and the carrying value of the generating stations, which was included in Operating and maintenance expense in Exelon's Consolidated Statements of Operations and Comprehensive Income.

See Note 4—Mergers, Acquisitions, and Dispositions for further information on asset sales.

In the fourth quarter of 2014, a significant decline in oil prices suggested that the carrying value of certain Upstream assets may be impaired. Generation concluded that the estimated undiscounted future cash flows and fair value of various Upstream properties, primarily located in Oklahoma and Texas, were less than their respective carrying values at December 31, 2014. As a result, long-lived assets with a combined net book value of approximately $163 million were written down to their fair value of $39 million and a pre-tax impairment charge of $124 million was recorded in Operating and maintenance expense in Exelon's Consolidated Statements of Operations and Comprehensive Income. After reflecting the impairment, Exelon has $189 million of Upstream assets remaining on its Consolidated Balance Sheets at December 31, 2014. Further declines in commodity prices could potentially result in future impairments of the Upstream assets.

The fair value analysis used in the above impairments was primarily based on the income approach using significant unobservable inputs (Level 3) including revenue, generation and production forecasts, projected capital and maintenance expenditures and discount rates. Changes in the assumptions described above could potentially result in future impairments of Exelon's long-lived assets, which could be material.

### 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 (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

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 operate the stations and keep or market the power itself or require the lessees to arrange for a third-party to bid on a service contract for a period following the lease term. 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 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.

On February 26, 2014, UII and the City Public Service Board of San Antonio, Texas (CPS) finalized an agreement to terminate the leases on the generating station located in Texas, as described above, prior to its expiration dates. As a result of the lease

**Combined Notes to Consolidated Financial Statements—(Continued)**
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termination, UII received a net early termination amount of $335 million from CPS and wrote down the net investment in the CPS long-term lease of $336 million in Investments in Exelon's Consolidated Balance Sheets in 2014; resulting in a pre-tax loss of $1 million being reflected in Operating and maintenance expense in the Consolidated Statements of Operations and Comprehensive Income in 2014.

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.

Based on the annual reviews performed in 2014 and 2013, the estimated residual value of Exelon's direct financing leases for the Georgia generating stations experienced other than temporary declines given reduced long-term energy and capacity price expectations. As a result, Exelon recorded a $24 million and $14 million pre-tax impairment charge in 2014 and 2013, respectively, for these stations. These impairment charges were recorded in Investments and Operating and maintenance expense in Exelon's Consolidated Balance Sheets and the Consolidated Statements of Operations and Comprehensive Income, 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, 2014, 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 2014.

At December 31, 2014 and 2013, the components of the net investment in long-term leases were as follows:

| | December 31, 2014 | December 31, 2013 |
|---|---|---|
| Estimated residual value of leased assets | $685 | $1,465 |
| Less: unearned income | 324 | 767 |
| Net investment in long-term leases | $361 | $ 698 |

### 9. Jointly Owned Electric Utility Plant

Exelon, Generation, PECO and BGE's undivided ownership interests in jointly owned electric plants and transmission facilities at December 31, 2014 and 2013 were as follows:

| | Nuclear generation | | | | Fossil fuel generation | | | Transmission | | Other |
|---|---|---|---|---|---|---|---|---|---|---|
| | Quad Cities | Peach Bottom | Salem [(a)] | Nine Mile Point Unit 2 [(g)] | Keystone [(f)] | Conemaugh [(f)] | Wyman | PA [(b)] | DE/NJ [(c)] | Other [(d)] |
| Operator | Generation | Generation | PSEG Nuclear | Generation | GenOn | GenOn | FP&L | First Energy | PSEG | |
| Ownership interest | 75.00% | 50.00% | 42.59% | 82.00% | — | — | 5.89% | Various | 42.55% | 44.24% |
| **Exelon's share at December 31, 2014:** | | | | | | | | | | |
| Plant [(e)] | $ 995 | $1,095 | $ 531 | $ 676 | $— | $— | $ 3 | $ 14 | $ 64 | $ 2 |
| Accumulated depreciation [(e)] | 266 | 343 | 150 | 14 | — | — | 3 | 7 | 34 | 1 |
| Construction work in progress | 15 | 133 | 29 | 48 | — | — | — | — | — | — |
| **Exelon's share at December 31, 2013:** | | | | | | | | | | |
| Plant [(e)] | $ 941 | $ 883 | $ 501 | $ — | $725 | $399 | $ 3 | $ 14 | $ 64 | $ 2 |
| Accumulated depreciation [(e)] | 226 | 326 | 134 | — | 268 | 220 | 3 | 7 | 34 | 1 |
| Construction work in progress | 27 | 174 | 24 | — | 6 | 121 | — | — | — | — |

**Combined Notes to Consolidated Financial Statements—(Continued)**
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(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, 2014 and 2013.
(b) PECO and BGE own a 22% and 7% share, respectively, in 127 miles of 500kV lines located in Pennsylvania; PECO and BGE also own a 20.7% and 10.56% share, respectively, of a 500kV substation immediately outside of the Conemaugh fossil generating station which supplies power to the 500kV lines including, but not limited to, the lines noted above.
(c) PECO owns a 42.55% share in 131 miles of 500kV 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.
(d) Generation has a 44.24% ownership interest in assets located at Merrill Creek Reservoir located in New Jersey.
(e) Excludes asset retirement costs.
(f) As of December 31, 2014, Generation sold its ownership interest in Keystone and Conemaugh. At December 31, 2013, Generation held 41.98% and 31.28% ownership interest in Keystone and Conemaugh, respectively. See Note 4—Mergers, Acquisitions, and Dispositions for additional information.
(g) On April 1, 2014, Generation assumed operational control of CENG's nuclear fleet, and as of that date, CENG's operations are consolidated into Generation's financial statements. As of December 31, 2013, Generation's ownership interest in CENG, including Nine Mile Point, was treated as an equity method investment, and thus did not represent an undivided Interest. See Note 5 - Investment in Constellation Energy Nuclear Group, LLC for additional information.

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 Purchased power and fuel and Operating and maintenance expenses on Exelon's Consolidated Statements of Operations and Comprehensive Income.

## 10. Intangible Assets

### Goodwill

Exelon's gross amount of goodwill, accumulated impairment losses and carrying amount of goodwill for the years ended December 31, 2014 and 2013 were as follows:

| | Gross Amount[(a)] | Accumulated Impairment Losses | Carrying Amount |
|---|---|---|---|
| Balance, January 1, 2013 | $4,608 | $1,983 | $2,625 |
| Goodwill from business combination | 47 | — | 47 |
| Balance, December 31, 2014 | $4,655 | $1,983 | $2,672 |

(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 its operating results are 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 operating results are 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.

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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.

***2014 Goodwill Impairment Assessment***. Pursuant to authoritative guidance, ComEd is required to test its goodwill for impairment annually and more frequently if an event occurs or circumstances change that suggest an impairment is more likely than not. ComEd performed a qualitative assessment as of November 1, 2014, for its 2014 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 as well as changes in certain market conditions, including the discount rate and EBITDA multiples, while also considering the passing margin from its last quantitative assessment performed as of November 1, 2013.

***Prior 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.

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.

**Combined Notes to Consolidated Financial Statements—(Continued)**
**(Dollars in millions, except per share data unless otherwise noted)**

### Other Intangible Assets

Exelon, Generation and ComEd's other intangible assets and liabilities, included in Unamortized energy contract assets and Other long-term assets and liabilities in their Consolidated Balance Sheets, consisted of the following as of December 31, 2014:

| | Weighted Average Amortization Years [h] | Gross | Accumulated Amortization | Net | Estimated amortization expense 2015 | 2016 | 2017 | 2018 | 2019 |
|---|---|---|---|---|---|---|---|---|---|
| *Unamortized Energy Contracts* [a] | | | | | | | | | |
| Exelon Wind [b] | 18.0 | $ 224 | $ (55) | $169 | $ 14 | $ 14 | $ 14 | $ 14 | $ 14 |
| Antelope Valley [c] | 25.0 | 190 | (12) | 178 | 8 | 8 | 8 | 8 | 8 |
| Constellation [d] | 1.5 | 1,499 | (1,451) | 48 | 19 | (31) | (21) | 11 | 8 |
| CENG [e] | 1.7 | (97) | 29 | (68) | (20) | (11) | (15) | (18) | (15) |
| Integrys [d] | 2.4 | 6 | (5) | 1 | (8) | 6 | 1 | 1 | — |
| *Customer Relationships* | | | | | | | | | |
| Constellation [d] | 12.4 | 214 | (58) | 156 | 18 | 18 | 18 | 18 | 17 |
| Integrys [d] | 10.0 | 48 | (1) | 47 | 5 | 5 | 5 | 5 | 5 |
| *Trade Names* | | | | | | | | | |
| Constellation [d] | 10.0 | 243 | (79) | 164 | 23 | 23 | 23 | 23 | 23 |
| Chicago settlement—1999 agreement [f] | 21.8 | 100 | (79) | 21 | 3 | 3 | 4 | 4 | 4 |
| Chicago settlement—2003 agreement [g] | 17.9 | 62 | (40) | 22 | 4 | 4 | 3 | 3 | 3 |
| Total intangible assets | | $2,489 | $(1,751) | $738 | $ 66 | $ 39 | $ 40 | $ 69 | $ 67 |

(a) Includes unamortized energy contract assets and liabilities on Exelon's Consolidated Balance Sheets. Excludes $26 million of other miscellaneous unamortized energy contracts that have been acquired at various points in time. The estimated amortization for these miscellaneous unamortized energy contracts is $4 million, $3 million, $0 million, $2 million and $2 million for 2015, 2016, 2017, 2018 and 2019, respectively.
(b) In December 2010, Generation acquired all of the equity interests of John Deere Renewables, LLC (later named Exelon Wind), adding 735MWs of installed, operating wind capacity located in eight states.
(c) In September 2011, Generation acquired all of the interest in Antelope Valley Solar Ranch One, a 230 MW solar project under development in northern Los Angeles County, CA from First Solar, Inc.
(d) See Note 4—Mergers, Acquisitions, and Dispositions for further information on these acquisitions.
(e) See Note 5—Investment in Constellation Energy Nuclear Group, LLC for additional information.
(f) 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.
(g) 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 deferred credits and other liabilities, and other long-term liabilities on Exelon's Consolidated Balance Sheets are being recognized ratably (approximately $2 million annually) as an offset to amortization expense over the remaining term of the franchise agreement.
(h) Weighted-average amortization period was calculated at the date of a) acquisition for acquired assets or b) settlement agreement.

The following table summarizes the amortization expense related to intangible assets and liabilities for each of the years ended December 31, 2014, 2013 and 2012:

| | For the Year Ended December 31, |
|---|---|
| 2014 [a] | $ 179 |
| 2013 [a] | 478 |
| 2012 [a] | 1,150 |

(a) Amortization of unamortized energy contracts totaling $135 million, $430 million and $1,110 million for the years ended December 31, 2014, 2013 and 2012, respectively, was recorded in Purchase power and fuel expense or Operating revenues within Exelon's Consolidated Statement of Operations and Comprehensive Income.

**Combined Notes to Consolidated Financial Statements—(Continued)**
**(Dollars in millions, except per share data unless otherwise noted)**

***Acquired Intangible Assets***

Accounting guidance for business combinations requires the acquirer to separately recognize identifiable intangible assets in the application of purchase accounting.

**Unamortized Energy Contracts.** Unamortized energy contract assets and liabilities represent the remaining unamortized fair value of non-derivative energy contracts that Generation has acquired. The valuation of unamortized energy contracts 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 fair value 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 Exelon Wind unamortized energy contracts are amortized on a straight line basis over the period in which the associated contract revenues are recognized as a decrease in Operating revenue within Exelon's and Generation's Consolidated Statement of Operations and Comprehensive Income. In the case of Antelope Valley, Constellation, CENG and Integrys, 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 acquisition dates through either Purchase power and fuel expense or Operating revenues within Exelon's and Generation's Consolidated Statement of Operations and Comprehensive Income.

**Customer Relationships.** The customer relationship intangible 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 fair value 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 accounting guidance requires that customer-based intangibles be amortized over the period expected to be benefited using the pattern of economic benefit. The amortization of the customer relationships is recorded in Depreciation and amortization expense within Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income.

**Trade Name.** The Constellation trade name intangible was determined based on the relief from royalty method of income approach whereby fair value is determined to be the present value of the license fees avoided by owning the assets. The fair value 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. The Constellation trade name intangible is amortized on a straight-line basis over a period of 10 years. The amortization of the trade name is recorded in Depreciation and amortization expense within Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income.

***Renewable Energy Credits and Alternative Energy Credits***

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). Purchased RECs are recorded at cost on the date they are purchased. The cost of RECs purchased on a stand-alone basis is based on the transaction price, while the cost of RECs acquired through PPAs represents the difference between the total contract price and the market price of energy at contract inception. 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, 2014, and 2013, PECO had current AECs of $13 million and $19 million, respectively. PECO had no noncurrent AECs and $5 million as of December 31, 2014, and 2013, respectively. As of December 31, 2014, and 2013, Generation had current RECs of $191 million and $158 million, respectively, and $44 million of noncurrent REC's as of December 31, 2014. As of December 31, 2014, and 2013, ComEd, had current RECs of $4 million and $3 million, respectively. See Note 3—Regulatory Matters and Note 22—Commitments and Contingencies for additional information on RECs and AECs.

**Combined Notes to Consolidated Financial Statements—(Continued)**
**(Dollars in millions, except per share data unless otherwise noted)**

## 11. Fair Value of Financial Assets and Liabilities

### *Fair Value of Financial Liabilities Recorded at the Carrying Amount*

The following tables present the carrying amounts and fair values of Exelon's short-term liabilities, long-term debt, SNF obligation, and trust preferred securities (long-term debt to financing trusts or junior subordinated debentures) as of December 31, 2014 and 2013:

| | December 31, 2014 | | | | | December 31, 2013 | |
|---|---|---|---|---|---|---|---|
| | Carrying Amount | Fair Value Level 1 | Fair Value Level 2 | Fair Value Level 3 | Fair Value Total | Carrying Amount | Fair Value |
| Short-term liabilities | $ 463 | $ 3 | $ 448 | $ 12 | $ 463 | $ 344 | $ 344 |
| Long-term debt (including amounts due within one year) | 21,164 | 1,208 | 20,417 | 1,311 | 22,936 | 19,132 | 19,751 |
| Long-term debt to financing trusts | 648 | — | — | 648 | 648 | 648 | 631 |
| SNF obligation | 1,021 | — | 833 | — | 833 | 1,021 | 790 |

*Short-Term Liabilities.* The short-term liabilities included in the tables above are comprised of dividends payable (included in other current liabilities) (Level 1), short-term borrowings (Level 2) and third party financing (Level 3). The Registrants' carrying amounts of the short-term liabilities are representative of fair value because of the short-term nature of these instruments.

*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 Exelon's equity units (Level 1) are valued based on publicly traded securities issued by Exelon.

The fair value of Generation's non-government-backed fixed rate project financing debt, including nuclear fuel procurement contracts, (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-backed 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 (Level 2).

*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.

***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.
- Level 2—inputs other than quoted prices included within Level 1 that are directly observable for the asset or liability or indirectly observable through corroboration with observable market data.
- Level 3—unobservable inputs, such as internally developed pricing models or third-party valuations for the asset or liability due to little or no market activity for the asset or liability.

Transfers in and out of levels are recognized as of the end of the reporting period when 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. There were no transfers between Level 1 and Level 2 during the year ended December 31, 2014 for cash equivalents, nuclear decommissioning trust fund investments, pledged assets for Zion Station decommissioning, Rabbi trust investments, and deferred compensation obligations.

**Combined Notes to Consolidated Financial Statements—(Continued)**
**(Dollars in millions, except per share data unless otherwise noted)**

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, 2014 and 2013:

| As of December 31, 2014 | Exelon | | | |
|---|---|---|---|---|
| | Level 1 | Level 2 | Level 3 | Total |
| **Assets** | | | | |
| Cash equivalents [(a)] | $ 1,119 | $ — | $ — | $ 1,119 |
| Nuclear decommissioning trust fund investments | | | | |
| Cash equivalents | 208 | 37 | — | 245 |
| Equity | | | | |
| Domestic | 2,423 | 2,207 | — | 4,630 |
| Foreign | 612 | — | — | 612 |
| Equity funds subtotal | 3,035 | 2,207 | — | 5,242 |
| Fixed income | | | | |
| Corporate debt securities | — | 2,023 | 239 | 2,262 |
| U.S. Treasury and agencies | 996 | — | — | 996 |
| Foreign governments | — | 95 | — | 95 |
| State and municipal debt | — | 438 | — | 438 |
| Other | — | 511 | — | 511 |
| Fixed income subtotal | 996 | 3,067 | 239 | 4,302 |
| Middle market lending | — | — | 366 | 366 |
| Private equity | — | — | 83 | 83 |
| Real estate | — | — | 3 | 3 |
| Other | — | 301 | — | 301 |
| Nuclear decommissioning trust funds subtotal [(b)] | 4,239 | 5,612 | 691 | 10,542 |
| Pledged assets for Zion Station decommissioning | | | | |
| Cash equivalents | — | 15 | — | 15 |
| Equities | 6 | 1 | — | 7 |
| Fixed income | | | | |
| U.S. Treasury and agencies | 5 | 3 | — | 8 |
| Corporate debt | — | 89 | — | 89 |
| State and municipal debt | — | 10 | — | 10 |
| Other | — | 3 | — | 3 |
| Fixed income subtotal | 5 | 105 | — | 110 |
| Middle market lending | — | — | 184 | 184 |
| Pledged assets for Zion Station decommissioning subtotal [(c)] | 11 | 121 | 184 | 316 |
| Rabbi trust investments [(d)] | | | | |
| Cash equivalents | 1 | — | — | 1 |
| Mutual funds [(e)] | 46 | — | — | 46 |
| Rabbi trust investments subtotal | 47 | — | — | 47 |
| Commodity derivative assets | | | | |
| Economic hedges | 1,667 | 3,465 | 1,681 | 6,813 |
| Proprietary trading | 201 | 284 | 27 | 512 |
| Effect of netting and allocation of collateral [(f)] | (1,982) | (2,757) | (557) | (5,296) |
| Commodity derivative assets subtotal | (114) | 992 | 1,151 | 2,029 |
| Interest rate and foreign currency derivative assets | | | | |
| Derivatives designated as hedging instruments | — | 31 | — | 31 |
| Economic hedges | — | 13 | — | 13 |
| Proprietary trading | 18 | 9 | — | 27 |
| Effect of netting and allocation of collateral | (17) | (31) | — | (48) |
| Interest rate and foreign currency derivative assets subtotal | 1 | 22 | — | 23 |
| Other investments | 2 | — | 3 | 5 |
| **Total assets** | 5,305 | 6,747 | 2,029 | 14,081 |

**Combined Notes to Consolidated Financial Statements—(Continued)**
**(Dollars in millions, except per share data unless otherwise noted)**

| As of December 31, 2014 | Exelon Level 1 | Level 2 | Level 3 | Total |
|---|---|---|---|---|
| **Liabilities** | | | | |
| Commodity derivative liabilities | | | | |
| Economic hedges | (2,241) | (3,458) | (995) | (6,694) |
| Proprietary trading | (195) | (295) | (42) | (532) |
| Effect of netting and allocation of collateral [f] | 2,416 | 3,557 | 729 | 6,702 |
| Commodity derivative liabilities subtotal | (20) | (196) | (308) | (524) |
| Interest rate and foreign currency derivative liabilities | — | — | — | — |
| Derivatives designated as hedging instruments | — | (41) | — | (41) |
| Economic hedges | — | (103) | — | (103) |
| Proprietary trading | (14) | (9) | — | (23) |
| Effect of netting and allocation of collateral | 25 | 29 | — | 54 |
| Interest rate and foreign currency derivative liabilities subtotal | 11 | (124) | — | (113) |
| Deferred compensation obligation | — | (107) | — | (107) |
| **Total liabilities** | (9) | (427) | (308) | (744) |
| **Total net assets** | $5,296 | $6,320 | $1,721 | $13,337 |

**Combined Notes to Consolidated Financial Statements—(Continued)**
**(Dollars in millions, except per share data unless otherwise noted)**

| As of December 31, 2013 | Exelon | | | |
|---|---|---|---|---|
| | Level 1 | Level 2 | Level 3 | Total |
| Assets | | | | |
| Cash equivalents (a) | $1,230 | $ — | $ — | $ 1,230 |
| Nuclear decommissioning trust fund investments | | | | |
| Cash equivalents | 459 | — | — | 459 |
| Equities | | | | |
| Domestic | 1,642 | 2,271 | — | 3,913 |
| Foreign | 249 | — | — | 249 |
| Equity funds subtotal | 1,891 | 2,271 | — | 4,162 |
| Fixed income | | | | |
| Corporate debt securities | — | 1,753 | 31 | 1,784 |
| U.S. Treasury and agencies | 882 | — | — | 882 |
| Foreign governments | — | 87 | — | 87 |
| State and municipal debt | — | 294 | — | 294 |
| Other | — | 75 | — | 75 |
| Fixed income subtotal | 882 | 2,209 | 31 | 3,122 |
| Middle market lending | — | — | 314 | 314 |
| Private equity | — | — | 5 | 5 |
| Other | — | 14 | — | 14 |
| Nuclear decommissioning trust funds subtotal (b) | 3,232 | 4,494 | 350 | 8,076 |
| Pledged assets for Zion Station decommissioning | | | | |
| Cash equivalents | — | 26 | — | 26 |
| Equities | 16 | — | — | 16 |
| Fixed income | | | | |
| U.S. Treasury and agencies | 45 | 4 | — | 49 |
| Corporate debt | — | 227 | — | 227 |
| State and municipal debt | — | 20 | — | 20 |
| Fixed income subtotal | 45 | 251 | — | 296 |
| Middle market lending | — | — | 112 | 112 |
| Other | — | 1 | — | 1 |
| Pledged assets for Zion Station decommissioning subtotal (c) | 61 | 278 | 112 | 451 |
| Rabbi trust investments (d) | | | | |
| Cash equivalents | 2 | — | — | 2 |
| Mutual funds (e) | 54 | — | — | 54 |
| Rabbi trust investments subtotal | 56 | — | — | 56 |
| Commodity 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 derivative assets subtotal | (46) | 766 | 577 | 1,297 |
| Interest rate and foreign currency derivative assets | 30 | 39 | — | 69 |
| Effect of netting and allocation of collateral | (30) | (2) | — | (32) |
| Interest rate and foreign currency derivative assets subtotal | — | 37 | — | 37 |
| Other investments | — | — | 15 | 15 |
| **Total assets** | 4,533 | 5,575 | 1,054 | 11,162 |

**Combined Notes to Consolidated Financial Statements—(Continued)**
**(Dollars in millions, except per share data unless otherwise noted)**

| | Exelon | | | |
|---|---|---|---|---|
| **As of December 31, 2013** | **Level 1** | **Level 2** | **Level 3** | **Total** |
| **Liabilities** | | | | |
| Commodity 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 derivative liabilities subtotal | 1 | (139) | (305) | (443) |
| Interest rate and foreign currency derivative liabilities | (31) | (17) | — | (48) |
| Effect of netting and allocation of collateral | 31 | 1 | — | 32 |
| Interest rate and foreign currency 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 |

(a) Excludes certain cash equivalents considered to be held-to-maturity and not reported at fair value.

(b) Excludes net liabilities of $5 million at both December 31, 2014 and 2013. 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 $3 million and $7 million at December 31, 2014 and 2013, respectively. These items consist of receivables related to pending securities sales, interest and dividend receivables, and payables related to pending securities purchases.

(d) Excludes $35 million and $32 million of cash surrender value of life insurance investment at December 31, 2014 and 2013, respectively, at Exelon Consolidated. Excludes $11 million and $10 million of cash surrender value of life insurance investment at December 31, 2014 and 2013, respectively, at Generation.

(e) The mutual funds held by the Rabbi trusts at Exelon Consolidated include $45 million related to deferred compensation and $1 million related to a Supplemental Executive Retirement Plan at December 31, 2014, and $53 million related to deferred compensation and $1 million related to a Supplemental Executive Retirement Plan at December 31, 2013.

(f) Includes collateral postings (received) to/from counterparties. Collateral posted (received) to/from counterparties, net of collateral paid to counterparties, totaled $434 million, $800 million and $172 million allocated to Level 1, Level 2 and Level 3 mark-to-market derivatives, respectively, as of December 31, 2014. Collateral posted (received) to/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.

**Combined Notes to Consolidated Financial Statements—(Continued)**
**(Dollars in millions, except per share data unless otherwise noted)**

The following table presents the fair value reconciliation of Level 3 assets and liabilities measured at fair value on a recurring basis during the year ended December 31, 2014 and 2013:

| | Generation | | | | | ComEd | | Exelon |
|---|---|---|---|---|---|---|---|---|
| For The Year Ended December 31, 2014 | Nuclear Decommissioning Trust Fund Investments | Pledged Assets for Zion Station Decommissioning | Mark-to-Market Derivatives | Other Investments | Total Generation | Other-ComEd [(b)] | Eliminated in Consolidation | Total |
| Balance as of January 1, 2014 | $350 | $112 | $ 465 | $ 15 | $ 942 | $(193) | $— | $ 749 |
| Total realized / unrealized gains (losses) | | | | | | | | |
| Included in net income | 6 | — | 526[(a)] | — | 532 | — | — | 532 |
| Included in noncurrent payables to affiliates | 14 | — | — | — | 14 | — | (14) | — |
| Included in payable for Zion Station decommissioning | — | 2 | — | — | 2 | — | — | 2 |
| Included in regulatory assets/ liabilities | — | — | — | — | — | (14) | 14 | — |
| Change in collateral | — | — | 198 | — | 198 | — | — | 198 |
| Purchases, sales, issuances and settlements | | | | | | | | |
| Purchases | 400 | 120 | 76[(c)] | 2 | 598 | — | — | 598 |
| Sales | (15) | (50) | (7) | (8) | (80) | — | — | (80) |
| Settlements | (64) | — | — | — | (64) | — | — | (64) |
| Transfers into Level 3 | — | — | (7) | — | (7) | — | — | (7) |
| Transfers out of Level 3 | — | — | (201) | (6) | (207) | — | — | (207) |
| Balance as of December 31, 2014 | $691 | $184 | $1,050 | $ 3 | $1,928 | $(207) | $— | $1,721 |
| The amount of total gains included in income attributed to the change in unrealized gains (losses) related to assets and liabilities as of December 31, 2014 | $ 4 | $— | $ 640 | $— | $ 644 | $ — | $— | $ 644 |

**Combined Notes to Consolidated Financial Statements—(Continued)**
**(Dollars in millions, except per share data unless otherwise noted)**

| | Generation | | | | | ComEd | | Exelon |
|---|---|---|---|---|---|---|---|---|
| For The Year Ended December 31, 2013 | Nuclear Decommissioning Trust Fund Investments | Pledged Assets for Zion Station Decommissioning | Mark-to-Market Derivatives [d] | Other Investments | Total Generation | Other-ComEd [b][f] | Eliminated in Consolidation | Total |
| Balance as of January 1, 2013 | $183 | $ 89 | $ 660 | $ 17 | $ 949 | $(293) | $ — | $ 656 |
| Total realized / unrealized gains (losses) | | | | | | | | |
| Included in net income | 2 | — | (51)[a] | — | (49) | — | 7 | (42) |
| Included in other comprehensive income | — | — | (219) | 2 | (217) | — | 219 | 2 |
| Included in noncurrent payables to affiliates | 8 | — | — | — | 8 | — | (8) | — |
| Included in payable for Zion Station decommissioning | — | — | — | — | — | — | — | — |
| Included in regulatory assets/ liabilities | — | — | — | — | — | 100 | (218) | (118) |
| Change in collateral | — | — | 7 | — | 7 | — | — | 7 |
| Purchases, sales, issuances and settlements | | | | | | | | |
| Purchases | 203 | 62 | 28 | 4 | 297 | — | — | 297 |
| Sales | (28) | (39) | (11) | (8) | (86) | — | — | (86) |
| Settlements | (18) | — | — | — | (18) | — | — | (18) |
| Transfers into Level 3 | — | — | 86[e] | 1 | 87 | — | — | 87 |
| Transfers out of Level 3 | — | — | (35) | (1) | (36) | — | — | (36) |
| Balance as of December 31, 2013 | $350 | $112 | $ 465 | $ 15 | $ 942 | $(193) | $ — | $ 749 |
| The amount of total gains included in income attributed to the change in unrealized gains (losses) related to assets and liabilities held as of December 31, 2013 | $ 1 | $— | $ 156 | $— | $ 157 | $ — | $ — | $ 168 |

(a) Includes the reclassification of $114 million and $207 million of realized gains due to the settlement of derivative contracts for the years ended December 31, 2014 and 2013, respectively.
(b) Includes $13 million and $133 million of decreases in fair value and $1 million and ($7) million of realized gains (losses) due to settlements associated with floating-to-fixed energy swap contracts with unaffiliated suppliers for the years ended December 31, 2014 and 2013, respectively.
(c) Includes $34 million of fair value from contracts acquired as a result of the Integrys acquisition.
(d) Includes $11 million of decreases in fair value and realized gains 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.
(e) Includes an increase of transfers into Level 3 arising from reductions in market liquidity, which resulted in less observable contract tenures in various locations.
(f) 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.

**Combined Notes to Consolidated Financial Statements—(Continued)**
**(Dollars in millions, except per share data unless otherwise noted)**

The following tables present the income statement classification of the total realized and unrealized gains (losses) included in income for Exelon's Level 3 assets and liabilities measured at fair value on a recurring basis during the years ended December 31, 2014 and 2013:

| | Operating Revenues | Purchased Power and Fuel | Other, net [(a)] |
|---|---|---|---|
| Total gains (losses) included in net income for the year ended December 31, 2014 | $614 | $(88) | $6 |
| Change in the unrealized gains (losses) relating to assets and liabilities held for the year ended December 31, 2014 | $663 | $(23) | $4 |

| | Operating Revenues | Purchased Power and Fuel | Other, net [(a)] |
|---|---|---|---|
| Total gains (losses) included in net 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 |

(a) Other, net activity consists of realized and unrealized gains (losses) included in income for the NDT funds held by Generation.

***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.* 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.* The trust fund investments have been established to satisfy Generation's and CENG's nuclear decommissioning obligations as required by the NRC. The NDT funds hold debt and equity securities directly and indirectly through commingled funds and mutual funds, which are included in Equities, Fixed Income and Other. Generation's and CENG'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, which are included in Domestic or Foreign equities, 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, which are included in Corporate debt, are determined using a third party valuation that contains significant unobservable inputs and are categorized in Level 3.

Equity, balanced 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, Generation, and CENG 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.

Private equity investments include investments in operating companies that are not publicly traded on a stock exchange. 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.

As of December 31, 2014, Generation has outstanding commitments to invest in middle market lending, corporate debt securities, private equity investments, and real estate investments of approximately $290 million. These commitments will be funded by Generation's existing nuclear decommissioning trust funds.

See Note 15—Asset Retirement Obligations for further discussion on the NDT fund investments.

*Rabbi Trust Investments.* 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.* 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.

**Combined Notes to Consolidated Financial Statements—(Continued)**
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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.* 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***

*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 other attributes. 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 more 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

**Combined Notes to Consolidated Financial Statements—(Continued)**
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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 $2.75 and $0.34 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 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.

The table below discloses the significant inputs to the forward curve used to value these positions.

| Type of trade | Fair Value at December 31,2014 | Valuation Technique | Unobservable Input | Range |
|---|---|---|---|---|
| Mark-to-market derivatives—Economic hedges (Generation) [(a)(c)] | $ 893 | Discounted Cash Flow | Forward power price | $ 15 - $120[(d)] |
| | | | Forward gas price | $1.52 - $14.02[(d)] |
| | | Option Model | Volatility percentage | 8% - 257% |
| Mark-to-market derivatives—Proprietary trading (Generation) [(a)(c)] | $ (15) | Discounted Cash Flow | Forward power price | $ 15 - $117[(d)] |
| Mark-to-market derivatives (ComEd) | $(207) | Discounted Cash Flow | Forward heat rate [(b)] | 8x - 9x |
| | | | Marketability reserve | 3.5% - 8% |
| | | | Renewable factor | 86% - 126% |

(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 three positions of $172 million as of December 31, 2014.
(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 $97 and $8.14, respectively, and would be approximately $76 for power proprietary trading.

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| Type of trade | Fair Value at December 31, 2013 | Valuation Technique | Unobservable Input | Range |
|---|---|---|---|---|
| Mark-to-market derivatives—Economic hedges (Generation) [a][c] | $ 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][c] | $ 3 | Discounted Cash Flow | Forward power price | $ 10 - $176[d] |
| Mark-to-market derivatives (ComEd) | $(193) | Discounted Cash Flow | Forward heat rate[b] | 8x - 9x |
| | | | 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 three 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.

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 price 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.

### 12. Derivative Financial Instruments

The Registrants use derivative instruments to manage commodity price risk and interest rate risk related to ongoing business operations.

**Combined Notes to Consolidated Financial Statements—(Continued)**
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***Commodity Price Risk***

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, 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 Constellation merger. Because the underlying forecasted transactions remained probable, the fair value of the effective portion of these cash flow hedges was frozen in Accumulated OCI and was reclassified to results of operations when the forecasted purchase or sale of the energy commodity occurred. The effect of this decision is that all derivative economic hedges related to 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. As such, Generation uses a variety of derivative and non-derivative instruments to manage the commodity price risk of its electric generation facilities, including power and gas 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, 2014, the percentage of expected generation hedged for the major reportable segments was 93%-96%, 61%-64% and 31%-34% for 2015, 2016, and 2017, respectively. The percentage of expected generation hedged is the amount of equivalent sales divided by the expected generation (which reflects the divestiture impact of Quail Run). Expected generation is the volume of energy that best represents our commodity position in energy markets from owned or contracted for capacity based upon a simulated dispatch model that makes assumptions regarding future market conditions, which are calibrated to market quotes for power, fuel, load following products, and options. 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. See Note 4—Mergers, Acquisitions, and Dispositions of the Combined Notes to Consolidated Financial Statements for more detail regarding divestitures.

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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 for the June 2013 through May 2014 procurement period. In addition, the ICC's December 18, 2013 Order approved the reduction of ComEd's commitments under those contracts for the June 2014 through May 2015 procurement period, and the amount of the reductions was approved in March 2014. 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 2014 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 2014 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 10,571 GWh, 8,762 GWh and 12,958 GWh

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for the years ended December 31, 2014, 2013 and 2012, are a complement to 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*

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, 2014, Exelon and Generation had $1,450 million and $550 million of notional amounts of fixed-to-floating hedges outstanding, respectively, and $3,070 million and $770 million of notional amounts of floating-to-fixed hedges outstanding, respectively. 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 $8 million decrease in Exelon Consolidated pre-tax income for the year ended December 31, 2014. 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 exchange hedges as of December 31, 2014:

| | Generation | | | | | Other | | | | Exelon |
|---|---|---|---|---|---|---|---|---|---|---|
| Description | Derivatives Designated as Hedging Instruments | Economic Hedges | Proprietary Trading (a) | Collateral and Netting (b) | Subtotal | Derivatives Designated as Hedging Instruments | Economic Hedges | Collateral and Netting (b) | Subtotal | Total |
| Mark-to-market derivative assets (current assets) | $ 7 | $ 7 | $ 20 | $(22) | $12 | $ 3 | $ — | $— | $ 3 | $ 15 |
| Mark-to-market derivative assets (noncurrent assets) | 1 | 5 | 7 | (7) | 6 | 20 | 1 | (19) | 2 | 8 |
| Total mark-to-market derivative assets | 8 | 12 | 27 | (29) | 18 | 23 | 1 | (19) | 5 | 23 |
| Mark-to-market derivative liabilities (current liabilities) | (8) | (2) | (14) | 25 | 1 | — | — | — | — | 1 |
| Mark-to-market derivative liabilities (noncurrent liabilities) | (4) | — | (9) | 10 | (3) | (29) | (101) | 19 | (111) | (114) |
| Total mark-to-market derivative liabilities | (12) | (2) | (23) | 35 | (2) | (29) | (101) | 19 | (111) | (113) |
| Total mark-to-market derivative net assets (liabilities) | $ (4) | $ 10 | $ 4 | $ 6 | $16 | $ (6) | $(100) | $— | $(106) | $ (90) |

(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.

**Combined Notes to Consolidated Financial Statements—(Continued)**
**(Dollars in millions, except per share data unless otherwise noted)**

The following table provides a summary of the interest rate and foreign exchange hedge balances recorded by the Registrants 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.

*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:

| | Year Ended December 31, | | | | | |
|---|---|---|---|---|---|---|
| | 2014 | 2013 | 2012 | 2014 | 2013 | 2012 |
| Income Statement Location | Gain (Loss) on Swaps | | | Gain (Loss) on Borrowings | | |
| Interest expense | $3 | $(24) | $(9) | $15 | $(3) | $(1) |

(a) For the years ended December 31, 2014 and 2013, the loss on Generation swaps included $(17) million and $16 million realized in earnings, respectively, with $4 million and $2 million excluded from hedge effectiveness testing, respectively.

During 2014, Exelon entered into $100 million and $75 million of notional amounts of fixed-to-floating fair value hedges related to interest rate swaps, which expire in 2019 and 2020, respectively. At December 31, 2014, Exelon and Generation had total outstanding fixed-to-floating fair value hedges related to interest rate swaps of $1,450 million and $550 million, with a derivative asset of $29 million and $7 million, respectively. At December 31, 2013, Exelon and Generation had outstanding fixed-to-floating fair value hedges related to interest rate swaps of $1,275 million and $550 million, with a derivative asset of $26 million and $23 million, respectively. During the years ended December 31, 2014 and 2013, the impact on the results of operations, as a result of the ineffectiveness from fair value hedges, was a $18 million gain and $2 million gain, respectively.

*Cash Flow Hedges.* In connection with the DOE guaranteed loan for the Antelope Valley project financings, 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 September 30, 2014. The interest rate swap was designated as a cash flow hedge, and as a result, unrealized losses of approximately $21 million have been recorded to Accumulated OCI, net on Exelon's Consolidated Balance Sheets. During the third quarter of 2014, the interest rate swap was terminated consistent with the agreements. The unrealized loss of $21 million will be amortized into Interest expense on Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income over the term of the DOE guaranteed loan.

**Combined Notes to Consolidated Financial Statements—(Continued)**
**(Dollars in millions, except per share data unless otherwise noted)**

During the third quarter of 2011, Sacramento PV Energy, a subsidiary of Generation, entered into floating-to-fixed interest rate swaps to manage a portion of its interest rate exposure in connection with the long-term borrowings. See Note 13—Debt and Credit Agreements for additional information regarding the financing. The swaps have a total notional amount of $26 million as of December 31, 2014 and expire in 2027. After the closing of the Constellation merger, the swaps were re-designated as cash flow hedges. At December 31, 2014, the subsidiary had a $3 million derivative liability related to these swaps.

During the third quarter of 2012, Constellation Solar Horizons, a subsidiary of Generation, entered into a floating-to-fixed interest rate swap to manage a portion of its interest rate exposure in connection with the long-term borrowings. See Note 13—Debt and Credit Agreements for additional information regarding the financing. The swap has a notional amount of $26 million as of December 31, 2014, and expires in 2030. This swap is designated as a cash flow hedge. At December 31, 2014, the derivative asset related to the swap was immaterial.

During the first quarter of 2014, ExGen Renewables I, LLC, a subsidiary of Generation, entered into floating-to-fixed interest rate swaps to manage a portion of its interest rate exposure in connection with the long-term borrowings. See Note 13—Debt and Credit Agreements for additional information regarding the financing. The swaps have a notional amount of $213 million as of December 31, 2014 and expire in 2020. The swaps are designated as cash flow hedges. At December 31, 2014, the subsidiary had a $2 million derivative liability related to the swaps.

During the third quarter of 2014, ExGen Texas Power, LLC, a subsidiary of Generation, entered into a floating-to-fixed interest rate swap to manage a portion of its interest rate exposure in connection with the long-term borrowing. See Note 13—Debt and Credit Agreements for additional information regarding the financing. The swaps have a notional amount of $505 million as of December 31, 2014 and expire in 2019. The swap was designated as a cash flow hedge in the fourth quarter of 2014. At December 31, 2014, the subsidiary had a $8 million derivative liability related to the swap.

During 2014, Exelon entered into $400 million of floating-to-fixed forward starting interest rate swaps to manage a portion of the interest rate exposure associated with the anticipated refinance of existing debt. The swaps are designated as cash flow hedges. At December 31, 2014, Exelon had a $28 million derivative liability related to the swaps.

During the years ended December 31, 2014 and 2013, the impact on the results of operations as a result of ineffectiveness from cash flow hedges was immaterial.

*Economic Hedges.* During 2014, Exelon entered into $1,900 million of floating-to-fixed forward starting interest rate swaps to manage a portion of the interest rate exposure associated with the anticipated future debt issuance related to the proposed PHI acquisition. At December 31, 2014, Exelon had a $100 million derivative liability related to the swaps.

During the fourth quarter, fixed-to-floating interest rate swaps, which were marked-to-market, acquired as part of the Constellation merger, expired for Exelon and Generation. The notional amounts of the swaps was $150 million.

At December 31, 2014, Generation had $126 million in notional amounts of interest rate derivative contracts to economically hedge risk associated with the interest rate component of commodity positions and $349 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.

***Fair Value Measurement and Accounting for the Offsetting of Amounts Related to Certain Contracts***

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 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

**Combined Notes to Consolidated Financial Statements—(Continued)**
**(Dollars in millions, except per share data unless otherwise noted)**

hedges and proprietary trading derivatives are shown gross. 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 including initial margin on exchange positions, is aggregated in the collateral and netting column. As of December 31, 2014 and 2013, $8 million and $10 million of cash collateral posted, respectively, was not offset against derivative positions because such collateral was not associated with any energy-related derivatives, were associated with accrual positions, 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.

The following table provides a summary of the derivative fair value balances recorded by the Registrants as of December 31, 2014:

| | Generation | | | | ComEd | Exelon |
|---|---|---|---|---|---|---|
| **Derivatives** | **Economic Hedges** | **Proprietary Trading** | **Collateral and Netting (a)** | **Subtotal (b)** | **Economic Hedges (c)** | **Total Derivatives** |
| Mark-to-market derivative assets (current assets) | $ 4,992 | $ 456 | $(4,184) | $1,264 | $ — | $1,264 |
| Mark-to-market derivative assets (noncurrent assets) | 1,821 | 56 | (1,112) | 765 | — | 765 |
| Total mark-to-market derivative assets | 6,813 | 512 | (5,296) | 2,029 | — | 2,029 |
| Mark-to-market derivative liabilities (current liabilities) | (4,947) | (468) | 5,200 | (215) | (20) | (235) |
| Mark-to-market derivative liabilities (noncurrent liabilities) | (1,540) | (64) | 1,502 | (102) | (187) | (289) |
| Total mark-to-market derivative liabilities | (6,487) | (532) | 6,702 | (317) | (207) | (524) |
| Total mark-to-market derivative net assets (liabilities) | $ 326 | $ (20) | $ 1,406 | $1,712 | $(207) | $1,505 |

(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 $(416) million and $(171) million, respectively, and current and noncurrent liabilities are shown net of collateral of $(599) million and $(220) million, respectively. The total cash collateral posted, net of cash collateral received and offset against mark-to-market assets and liabilities was $1,406 million at December 31, 2014.

(c) Includes current and noncurrent liabilities relating to floating-to-fixed energy swap contracts with unaffiliated suppliers.

**Combined Notes to Consolidated Financial Statements—(Continued)**
**(Dollars in millions, except per share data unless otherwise noted)**

The following table provides a summary of the derivative fair value balances recorded by the Registrants as of December 31, 2013:

| | Generation | | | | ComEd | Exelon |
|---|---|---|---|---|---|---|
| **Derivatives** | **Economic Hedges** | **Proprietary Trading** | **Collateral and Netting (a)** | **Subtotal (b)** | **Economic Hedges (c)** | **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. Current liabilities are shown net of collateral of $(12) million. Collateral related to noncurrent liabilities was $0 million. 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.

*Cash Flow Hedges.* As discussed previously, effective prior to the Constellation merger, Generation de-designated all of its cash flow hedges relating to commodity price risk. Because the underlying forecasted transactions remain at least reasonably probable, 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 $2 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. See Note 13—Debt and Credit Agreements for information about reclassifications from Accumulated OCI on interest rate swap activity that occurred after December 31, 2014.

**Combined Notes to Consolidated Financial Statements—(Continued)**
**(Dollars in millions, except per share data unless otherwise noted)**

The tables below provide the activity of Accumulated OCI related to cash flow hedges for the years ended December 31, 2014 and 2013, 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 | |
|---|---|---|---|
| | | Generation | Exelon |
| | Income Statement Location | Energy-Related Hedges | Total Cash Flow Hedges |
| Accumulated OCI derivative gain at January 1, 2013 | | $ 532[(a)(d)] | $ 368 |
| Effective portion of changes in fair value | | — | 29[(e)] |
| Reclassifications from accumulated OCI to net income | Operating Revenues | (413)[(c)(b)] | (277) |
| Ineffective portion recognized in income | Operating Revenues | — | — |
| Accumulated OCI derivative gain at December 31, 2013 | | 119[(d)] | 120 |
| Effective portion of changes in fair value | | — | (31)[(e)] |
| Reclassifications from accumulated OCI to net income | Operating Revenues | (117)[(b)] | (117) |
| Accumulated OCI derivative gain at December 31, 2014 | | $ 2[(d)] | $ (28) |

(a) Includes $133 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.
(b) Amount is net of related income tax expense of $78 million and $270 million for the years ended December 31, 2014 and 2013, respectively.
(c) Includes $133 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 year ended December 31, 2013.
(d) Excludes $20 million and $5 million, of losses, net of taxes, related to interest rate swaps and treasury rate locks for the years ended December 31, 2014 and 2013, respectively.
(e) Includes $15 million and $15 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 years ended December 31, 2014 and 2013, respectively.

During the years ended December 31, 2014, 2013, and 2012, 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 $195 million, $683 million and $1,368 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 for the year ended December 31, 2012.

The effect of Exelon's former energy-related cash flow hedge activity impact on pre-tax earnings based on the reclassification adjustment from Accumulated OCI to earnings was a $195 million, $464 million and $747 million pre-tax gain for the years ended December 31, 2014, 2013 and 2012, respectively. Changes in cash flow hedge ineffectiveness, primarily due to changes in market prices, were losses of $5 million for the year ended December 31, 2012. 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 Constellation merger date.

**Combined Notes to Consolidated Financial Statements—(Continued)**
**(Dollars in millions, except per share data unless otherwise noted)**

*Economic Hedges.* 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 ("treasury") 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. Exelon entered into floating-to-fixed forward starting interest rate swaps to manage interest rate risks associated with anticipated future debt issuance related to the proposed PHI acquisition. For the years ended December 31, 2014, 2013 and 2012, 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, or interest expense at Exelon in the Consolidated Statements of Operations and Comprehensive Income and are included in "Net fair value changes related to derivatives" in Exelon'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 Corporate | Exelon |
|---|---|---|---|---|---|---|---|
| **Year Ended December 31, 2014** | **Operating Revenues** | **Purchased Power and Fuel** | **Interest Expense** | **Total** | **Operating Revenues [(a)]** | **Interest Expense** | **Total** |
| Change in fair value of commodity positions | $(413) | $(194) | $— | $(607) | $— | $ — | $(607) |
| Reclassification to realized at settlement of commodity positions | 231 | (223) | — | 8 | — | — | 8 |
| Net commodity mark-to-market gains (losses) | (182) | (417) | — | (599) | — | — | (599) |
| Change in fair value of treasury positions | 10 | — | (2) | 8 | — | (100) | (92) |
| Reclassification to realized at settlement of treasury positions | (2) | — | — | (2) | — | — | (2) |
| Net treasury mark-to market gains (losses) | 8 | — | (2) | 6 | — | (100) | (94) |
| Net mark-to market gains (losses) | $(174) | $(417) | $ (2) | $(593) | $— | $(100) | $(693) |

| | Generation | | | | Intercompany Eliminations | Exelon Corporate | Exelon |
|---|---|---|---|---|---|---|---|
| **Year Ended December 31, 2013** | **Operating Revenues** | **Purchased Power and Fuel** | **Interest Expense** | **Total** | **Operating Revenues [(a)]** | **Interest Expense** | **Total** |
| Change in fair value of commodity positions | $286 | $180 | $— | $466 | $ (6) | $— | $460 |
| Reclassification to realized at settlement of commodity positions | (64) | 104 | — | 40 | 13 | — | 53 |
| Net commodity mark-to-market gains (losses) | 222 | 284 | — | 506 | 7 | — | 513 |
| Change in fair value of treasury positions | (1) | — | (4) | (5) | — | — | (5) |
| Reclassification to realized at settlement of treasury positions | (1) | — | — | (1) | — | — | (1) |
| Net treasury mark-to market gains (losses) | (2) | — | (4) | (6) | — | — | (6) |
| Net mark-to market gains (losses) | $220 | $284 | $ (4) | $500 | $ 7 | $— | $507 |

**Combined Notes to Consolidated Financial Statements—(Continued)**
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| Year Ended December 31, 2012 | Generation Operating Revenues | Generation Purchased Power and Fuel | Generation Interest Expense | Generation Total | Intercompany Eliminations Operating Revenues (a) | Exelon Corporate Interest Expense | Exelon Total |
|---|---|---|---|---|---|---|---|
| Change in fair value of commodity positions | $(362) | $215 | $— | $(147) | $ (94) | $— | $(241) |
| Reclassification to realized at settlement of commodity positions | 432 | 238 | — | 670 | 101 | — | 771 |
| Net commodity mark-to-market gains (losses) | 70 | 453 | — | 523 | 7 | — | 530 |
| Change in fair value of treasury positions | — | — | 6 | 6 | — | — | 6 |
| Reclassification to realized at settlement of treasury positions | (3) | — | — | (3) | — | — | (3) |
| Net treasury mark-to market gains (losses) | (3) | — | 6 | 3 | — | — | 3 |
| Net mark-to market gains (losses) | $ 67 | $453 | $ 6 | $ 526 | $ 7 | $— | $ 533 |

(a) Prior to the Constellation merger, the five-year financial swap contract between Generation and ComEd was de-designated. As a result, all prospective changes in fair value were recorded to operating revenues and eliminated in consolidation.

*Proprietary Trading Activities.* For the years ended December 31, 2014, 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 commodity derivative instruments entered into for proprietary trading purposes and interest rate derivative contracts to hedge risk associated with the interest rate component of underlying commodity positions. Gains and losses associated with proprietary trading are reported as operating revenue in Exelon's Consolidated Statements of Operations and Comprehensive Income and are included in "Net fair value changes related to derivatives" in Exelon'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, 2014 | 2013 | 2012 |
|---|---|---|---|---|
| Change in fair value of commodity positions | Operating Revenues | $ (1) | $(22) | $ (13) |
| Reclassification to realized at settlement of commodity positions | Operating Revenues | (29) | (15) | 108 |
| Net commodity mark-to-market gains (losses) | Operating Revenues | (30) | (37) | 95 |
| Change in fair value of treasury positions | Operating Revenues | 1 | 1 | 1 |
| Reclassification to realized at settlement of treasury positions | Operating Revenues | 3 | (3) | — |
| Net treasury mark-to market gains (losses) | Operating Revenues | 4 | (2) | 1 |
| Net mark-to market gains (losses) | Operating Revenues | $(26) | $(39) | $ 96 |

### *Credit Risk*

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

**Combined Notes to Consolidated Financial Statements—(Continued)**
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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.

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, 2014. 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 exclude credit risk exposure from individual retail counterparties, Nuclear fuel procurement contracts and exposure through RTOs, ISOs, NYMEX, ICE and Nodal commodity exchanges, further discussed in QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK. Additionally, the figures in the tables below exclude exposures with affiliates, including net receivables with ComEd, PECO and BGE of $43 million, $29 million and $40 million, respectively.

| Rating as of December 31, 2014 | 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 | $1,629 | $ 62 | $1,567 | 1 | $452 |
| Non-investment grade | 49 | 19 | 30 | — | — |
| No external ratings | | | | | |
| Internally rated—investment grade | 479 | — | 479 | — | — |
| Internally rated—non-investment grade | 60 | 4 | 56 | — | — |
| Total | $2,217 | $ 85 | $2,132 | 1 | $452 |

| Net Credit Exposure by Type of Counterparty | December 31, 2014 |
|---|---|
| Financial institutions | $ 295 |
| Investor-owned utilities, marketers, power producers | 958 |
| Energy cooperatives and municipalities | 862 |
| Other | 17 |
| Total | $2,132 |

(a) As of December 31, 2014, credit collateral held from counterparties where Generation had credit exposure included $69 million of cash and $16 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, 2014, ComEd's net 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

**Combined Notes to Consolidated Financial Statements—(Continued)**
**(Dollars in millions, except per share data unless otherwise noted)**

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, 2014, 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, 2014, PECO had credit exposure of $8 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, 2014, BGE had no net credit exposure to 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, 2014, BGE had credit exposure of $8 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***

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.

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

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, 2014 | 2013 |
|---|---|---|
| Gross Fair Value of Derivative Contracts Containing this Feature [(a)] | $(1,433) | $(1,056) |
| Offsetting Fair Value of In-the-Money Contracts Under Master Netting Arrangements [(b)] | 1,140 | 846 |
| Net Fair Value of Derivative Contracts Containing This Feature [(c)] | $ (293) | $ (210) |

(a) Amount represents the gross fair value of out-of-the-money derivative contracts containing credit-risk-related contingent features 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 $1,497 million and letters of credit posted of $672 million, and cash collateral held of $77 million and letters of credit held of $24 million as of December 31, 2014 for counterparties with derivative positions. Generation had cash collateral posted of $72 million and letters of credit posted of $364 million and cash collateral held of $206 million and letters of credit held of $34 million at December 31, 2013 for counterparties with derivative positions. In the event of a credit downgrade below investment grade (i.e. to BB+ by S&P or Ba1 by Moody's), Generation would have been required to post additional collateral of $2.4 billion and $2.0 billion as of December 31, 2014 and 2013, respectively. 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, 2014, Generation's and Exelon's swaps were in a liability position, with a fair value of $16 million and $90 million, respectively.

See Note 24—Segment Information for further 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, 2014, ComEd held approximately $2 million 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, 2014, 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 3—Regulatory Matters 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, 2014, PECO was not required to post collateral for any of these agreements. If PECO lost its investment grade credit rating as of December 31, 2014, PECO could have been required to post approximately $36 million of collateral to its counterparties.

**Combined Notes to Consolidated Financial Statements—(Continued)**
**(Dollars in millions, except per share data unless otherwise noted)**

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.

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, 2014, BGE was not required to post collateral for any of these agreements. If BGE lost its investment grade credit rating as of December 31, 2014, BGE could have been required to post approximately $79 million of collateral to its counterparties.

## 13. Debt and Credit Agreements

***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, 2014 and 2013:

| | 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, | |
|---|---|---|---|---|---|---|
| **Commercial Paper Issuer** | **2014 (a)(b)** | **2013 (a)(b)** | **2014** | **2013** | **2014** | **2013** |
| Exelon Corporate | $ 500 | $ 500 | $— | $— | — % | 0.27% |
| Generation | 5,600 | 5,600 | — | — | 0.32% | 0.32% |
| ComEd | 1,000 | 1,000 | 304 | 184 | 0.33% | 0.40% |
| PECO | 600 | 600 | — | — | n.a. | n.a. |
| BGE | 600 | 600 | 120 | 135 | 0.29% | 0.31% |
| **Total** | $8,300 | $8,300 | $424 | $319 | | |

(a) Reflects aggregate bank commitments under the revolving and bilateral credit agreements (with the exception of $200 million bilateral agreements for Generation) that backstop the commercial paper program. See discussion below and Credit Agreements table below for items affecting effective program size.

(b) 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 expired on October 17, 2014 and were renewed at the same amount through October 16, 2015. These facilities are solely utilized to issue letters of credit. As of December 31, 2014, letters of credit issued under these agreements totaled $9 million, $16 million, $21 million and $1 million for Generation, ComEd, PECO and BGE, respectively. Also, excludes the unsecured bridge credit facility of $3.2 billion at December 31, 2014, to support the PHI transaction discussed below.

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.

**Combined Notes to Consolidated Financial Statements—(Continued)**
**(Dollars in millions, except per share data unless otherwise noted)**

At December 31, 2014, the Registrants had the following aggregate bank commitments, credit facility borrowings and available capacity under their respective credit agreements:

| | | | | Available Capacity at December 31, 2014 | |
|---|---|---|---|---|---|
| Borrower | Aggregate Bank Commitment [(a)] | Facility Draws | Outstanding Letters of Credit [(c)] | Actual | To Support Additional Commercial Paper [(b)] |
| Exelon Corporate | $ 500 | $— | $ 6 | $ 494 | $ 494 |
| Generation | 5,800 | — | 1,181 | 4,619 | 4,504 |
| ComEd | 1,000 | — | 2 | 998 | 694 |
| PECO | 600 | — | 1 | 599 | 599 |
| BGE | 600 | — | — | 600 | 480 |
| **Total** | $8,500 | $— | $1,190 | $7,310 | $6,771 |

(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 expired on October 17, 2014 and were renewed at the same amount through October 16, 2015. These facilities are solely utilized to issue letters of credit. As of December 31, 2014, letters of credit issued under these agreements totaled $9 million, $16 million, $21 million and $1 million for Generation, ComEd, PECO and BGE, respectively. Also, excludes the unsecured bridge credit facility of $3.2 billion at December 31, 2014, to support the PHI transaction discussed below.
(b) Excludes $200 million bilateral credit facilities that do not back Generation's commercial paper program.
(c) Excludes nonrecourse debt letters of credit, see discussion below on Continental Wind.

As of December 31, 2014, there were no borrowings under the Registrants' credit facilities.

The following tables present the short-term borrowings activity for Exelon, during 2014, 2013 and 2012.

| | 2014 | 2013 | 2012 |
|---|---|---|---|
| Average borrowings | $ 571 | $ 254 | $ 199 |
| Maximum borrowings outstanding | 1,164 | 682 | 505 |
| Average interest rates, computed on a daily basis | 0.32% | 0.37% | 0.48% |
| Average interest rates, at December 31 | 0.53% | 0.35% | n.a. |

***Credit Facilities***

On March 28, 2014, ComEd extended for an additional year the expiration date of 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, 2019. The credit facility also allows ComEd to request increases in the aggregate commitments of up to an additional $500 million. Any 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 May 30, 2014, each of Exelon Corporate, Generation, PECO and BGE extended the expiration date of its unsecured revolving credit facility with aggregate bank commitments of $500 million, $5.3 billion, $600 million and $600 million, respectively, into May 2019, with the exception of a cumulative amount of $315 million in commitments, which expire in April 2018. Costs incurred to extend these facilities were not material.

On October 24, 2014, a $100 million bilateral CENG credit facility was amended and extended for an additional year. This facility has been utilized by CENG to fund working capital and capital projects. This facility does not back Generation's commercial paper program.

On November 24, 2014, Generation entered into a $25 million bilateral credit facility, scheduled to mature in December of 2016. This facility does not currently back Generation's commercial paper program.

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

On January 9, 2015, Generation amended and extended its $75 million bilateral credit facility for an additional two years. This facility does not back Generation's commercial paper program.

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, 7.5, 0.0 and 0.0 basis points for prime based borrowings and 127.5, 127.5, 107.5, 90.0 and 100.0 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' revolving credit facilities would not constitute an event of default under any of the other Registrants' revolving 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 revolving credit facility would constitute an event of default under the Exelon Corporation revolving credit facility.

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, 2014:

| | 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, 2014, the interest coverage ratios at the Registrants were as follows:

| | Exelon | Generation | ComEd | PECO | BGE |
|---|---|---|---|---|---|
| Interest coverage ratio | 9.19 | 12.35 | 7.03 | 8.72 | 9.28 |

***Credit Agreements***

In May 2014, concurrently and in connection with entering into the agreement to acquire PHI, Exelon entered into a credit facility to which the lenders committed to provide Exelon a 364-day senior unsecured bridge credit facility of $7.2 billion to support the contemplated transaction and provide flexibility for timing of permanent financing. The bridge credit facility was subsequently reduced to $3.2 billion as a result of the June 2014 debt and equity security issuances discussed below, as well as, the net after-tax proceeds from generating asset divestitures during the second half of 2014. During the year ended December 31, 2014, Exelon recorded $31 million to interest expense in connection with the bridge facility to temporarily finance the PHI acquisition. It is not currently expected that Exelon will be required to draw upon this credit facility to finance the proposed PHI acquisition.

***Junior Subordinated Notes***

In June 2014, Exelon issued $1.15 billion of junior subordinated notes in the form of 23 million equity units at a stated amount of $50.00 per unit. Net proceeds from the issuance were $1.11 billion, net of a $35 million underwriter fee. The net proceeds are expected to be used to finance a portion of the acquisition of PHI and for general corporate purposes.

Each equity unit represents an undivided beneficial ownership interest in Exelon's 2.5% junior subordinated notes due in 2024 and a forward equity purchase contract which settles in 2017. The junior subordinated notes are expected to be remarketed in 2017. In connection with the remarketing, Exelon may modify the maturity date of the notes to a date earlier than June 1, 2024 but not earlier than June 1, 2020, remove redemption provisions of the notes, or change the interest rate on the notes, including changing the interest rate from fixed to floating. Investors that participate in the remarketing receive the remarketing proceeds and may use those funds to either settle the equity forward upon settlement date or invest in the remarketed debt and use other funds for the share purchase. Exelon intends to use the remarketing proceeds to repay debt issued or for other corporate purposes as soon as practical following such settlements. If the remarketing fails, holders of the notes will have the right to put their notes to Exelon for an amount equal to the principal amount of notes held by such holder plus accrued interest. The equity units carry a total annual distribution rate of 6.5%, which is comprised of a quarterly coupon rate of interest of 2.5% and a quarterly contract payment of 4.0% (contract payments).

Each purchase contract obligates the holder to purchase, and Exelon to sell, for $50.00 a number of shares of Exelon's common stock in accordance with the conversion ratios set forth below:

- If the market price equals or exceeds $43.7484, then 1.1429 shares.
- If the market price is less than $43.7484 but greater than $35.00, a number of shares of common stock having a value, based on the market price, equal to $50.00.
- If the market price is less than or equal to $35.00, then 1.4286 shares.

A holder's ownership interest in the notes is pledged to Exelon to secure the holder's obligation under the related forward equity purchase contract. If a holder of the forward equity purchase contract chooses at any time to no longer be a holder of the notes, such holder's obligation under the purchase contract must be secured by a U.S. Treasury security.

At the time of issuance, Exelon determined that the forward equity purchase contract had no value and therefore the entire $1.15 billion of junior subordinated notes were allocated to debt and recorded within Long-term debt on Exelon's Consolidated Balance Sheet. Additionally, at the time of issuance, the present value of the contract payments of $131 million were recorded to Long-term debt, representing the obligation to make contract payments, with an offsetting reduction to Common stock. The obligation for the contract payments will be accreted to interest expense over the 3 year period ending in 2017 in Exelon's Consolidated Statement of Operations and Comprehensive Income. The Long-term debt recorded for the contract payments is considered a non-cash financing transaction that was excluded from Exelon's Consolidated Statements of Cash Flows. Until settlement of the equity purchase contract, earnings per share dilution resulting from the equity unit issuance will be determined under the treasury stock method.

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

***Long-Term Debt***

The following tables present the outstanding long-term debt at Exelon as of December 31, 2014 and 2013:

| | Rates | Maturity Date | December 31, 2014 | December 31, 2013 |
|---|---|---|---|---|
| **Long-term debt** | | | | |
| Rate stabilization bonds | 5.72% — 5.82% | 2017 | $ 195 | $ 265 |
| First mortgage bonds [a][b] | 1.20% — 6.45% | 2015 - 2044 | 8,079 | 7,746 |
| Senior unsecured notes | 2.00% — 7.60% | 2015 - 2042 | 7,071 | 7,571 |
| Unsecured bonds | 2.80% — 6.35% | 2016 - 2036 | 1,750 | 1,750 |
| Pollution control note | 4.10% | 2014 | — | 20 |
| Nuclear fuel procurement contracts | 3.25% — 3.35% | 2018 | 70 | — |
| Junior subordinated notes | 6.50% | 2017 | 1,150 | — |
| Nonrecourse debt: | | | | |
| Fixed rates | 2.33% — 6.00% | 2031 - 2037 | 1,166 | 1,077 |
| Variable rates | 2.41% — 5.00% | 2019 - 2030 | 1,101 | 150 |
| Notes payable and other [c] | 6.95% — 7.83% | 2015 - 2053 | 174 | 181 |
| **Total long-term debt** | | | 20,756 | 18,760 |
| Unamortized debt discount and premium, net | | | (37) | (19) |
| Fair value adjustment | | | 441 | 384 |
| Fair value hedge carrying value adjustment, net | | | 4 | 7 |
| Long-term debt due within one year | | | (1,802) | (1,509) |
| **Long-term debt** | | | $19,362 | $17,623 |
| **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.
(c) Includes capital lease obligations of $32 million and $41 million at December 31, 2014 and 2013, respectively. Lease payments of $3 million, $4 million, $4 million, $4 million, $5 million and $12 million will be made in 2015, 2016, 2017, 2018, 2019 and thereafter, respectively.
(d) Amounts owed to these financing trusts are recorded as Long-term debt to financing trusts within Exelon's Consolidated Balance Sheets.

Long-term debt maturities at Exelon in the periods 2014 through 2019 and thereafter are as follows:

| Year | Exelon |
|---|---|
| 2015 | $ 1,739 |
| 2016 | 1,269 |
| 2017 | 2,400 |
| 2018 | 1,415 |
| 2019 | 982 |
| Thereafter | 13,599[a] |
| Total | $21,404 |

(a) Includes $648 million due to ComEd, PECO and BGE financing trusts.

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***Nonrecourse Debt***

Exelon and Generation have issued nonrecourse debt financing, in which approximately $2.7 billion of generating assets have been pledged as collateral at December 31, 2014.

***Denver Airport.*** In June 2011, Generation entered into a 20-year, $7 million solar loan agreement, fully amortizing by June 30, 2031 related to a solar construction project in Denver, Colorado. The agreement bears interest at a fixed rate of 5.50% annually with interest payable annually. As of December 31, 2014, $7 million was outstanding.

***CEU Upstream.*** In July 2011, Generation entered into 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. The agreement is scheduled to expire on January 14, 2019, at a fixed rate of 2.41% annually with interest payable quarterly. As of December 31, 2014, $77 million was outstanding under the facility. 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, 2014, Generation was in compliance with this provision.

***Sacramento PV Energy.*** In July 2011, a subsidiary of Generation entered into a 19-year, $41 million nonrecourse note to finance a 30MW solar facility in Sacramento, California. The note bears interest at a variable rate equal to the six-month LIBOR plus 2.25%. Interest is payable quarterly and is secured by the equity interests and assets of the subsidiary. The note is scheduled to mature on December 31, 2030. As of December 31, 2014, $35 million was outstanding. The subsidiary also executed interest rate swaps with an initial notional value of $30 million in order to convert the variable interest payments to fixed payments on 75% of the $41 million facility amount, as required by the debt covenants. See Note 12—Derivative Financial Instruments for additional information regarding interest rate swaps.

***Holyoke Solar Cooperative.*** In October 2011, Generation entered into a 20-year, $10 million solar loan agreement, fully amortizing by December 31, 2031 related to a solar construction project in Holyoke, Massachusetts. The agreement bears interest at a fixed rate of 5.25% annually with interest payable monthly. As of December 31, 2014, $10 million was outstanding. The agreement includes a provision that requires Generation to establish and maintain a reserve fund to be held by Holyoke Solar Cooperative. As of December 31, 2014, Generation was in compliance with this provision.

***Antelope Valley Solar Ranch One.*** In December 2011, the DOE Loan Programs Office issued a guarantee for up to $646 million for a nonrecourse loan from the Federal Financing Bank to support the financing of the construction of the Antelope Valley facility. The project became fully operational 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. As of December 31, 2014, $557 million was outstanding.

In addition, Generation has issued letters of credit to support its equity investment in the project. As of December 31, 2014, Generation had $156 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. Generation expects to contribute approximately $2 million in additional equity contributions.

In connection with this agreement, on September 28, 2011, Generation entered into a floating-to-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. During the third quarter of 2014, the original interest rate swap was terminated, consistent with the agreements. See Note 12—Derivative Financial Instruments for additional information regarding the interest rate swaps associated with Antelope Valley.

***Constellation Solar Horizons.*** In September 2012, a subsidiary of Generation entered into an 18-year $38 million nonrecourse note to recover capital used to build a 16MW solar facility in Emmitsburg, Maryland. The note is schedule to mature on September 7, 2030. The note bears interest at a variable rate equal to the three-month LIBOR plus 2.25%. Interest is payable quarterly, and the

**Combined Notes to Consolidated Financial Statements—(Continued)**
**(Dollars in millions, except per share data unless otherwise noted)**

note is secured by the equity interests and assets of the subsidiary. As of December 31, 2014, $34 million was outstanding. The subsidiary also executed interest rate swaps for an initial notional amount of $29 million in order to convert the variable interest payments to fixed payments on 75% of the $38 million facility amount, as required by the debt covenants. See Note 12—Derivative Financial Instruments for additional information regarding interest rate swaps.

***Continental Wind.*** In September 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 with interest payable semi-annually. 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 667MW. The net proceeds were distributed to Generation for its general business purposes. As of December 31, 2014, $592 million was outstanding. In connection with this nonrecourse 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, 2014, the Continental Wind letter of credit facility had $47 million in letters of credit outstanding related to the project.

***ExGen Renewables I.*** On February 6, 2014, ExGen Renewables I, LLC (EGR), an indirect subsidiary of Exelon and Generation, borrowed $300 million aggregate principal amount pursuant to a nonrecourse senior secured loan, due February 6, 2021. The proceeds were distributed to Generation for its general business purposes. The loan bears interest at a variable rate equal to LIBOR plus 4.25%, subject to a 1% floor with interest payable quarterly. EGR indirectly owns Continental Wind. As of December 31, 2014, $282 million was outstanding. In addition to the financing, EGR entered into interest rate swaps with an initial notional amount of $240 million at an interest rate of 2.03% to manage a portion of the interest rate exposure in connection with the financing. See Note 12—Derivative Financial Instruments for additional information regarding interest rate swaps.

***ExGen Texas Power.*** In September 2014, ExGen Texas Power, LLC (EGTP), an indirect subsidiary of Exelon and Generation, issued $675 million aggregate principal amount of a nonrecourse senior secured term loan, scheduled to mature on September 18, 2021. The net proceeds were distributed to Generation for general business purposes. The term loan bears interest at a variable rate equal to LIBOR plus 4.75%, subject to a 1% LIBOR floor with interest payable quarterly. As of December 31, 2014, $673 million was outstanding. As part of the agreement, a revolving credit facility was established for the amount of $20 million available through, and scheduled to mature on September 18, 2019. In addition to the financing, EGTP entered into interest rate swaps with an initial notional amount of approximately $505 million at an interest rate of 2.34% to hedge a portion of the interest rate exposure in connection with this financing, as required by the debt covenants. See Note 12—Derivative Financial Instruments for additional information regarding interest rate swaps.

## 14. Income Taxes

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

| | For the Year Ended December 31, | | |
|---|---|---|---|
| | 2014 | 2013 | 2012 |
| Included in operations: | | | |
| Federal | | | |
| Current | $121 | $ 744 | $ 37 |
| Deferred | 576 | 140 | 701 |
| Investment tax credit amortization | (20) | (15) | (11) |
| State | | | |
| Current | 42 | 181 | (25) |
| Deferred | (53) | (6) | (75) |
| Total | $666 | $1,044 | $627 |

**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, | | |
|---|---|---|---|
| | 2014 | 2013 | 2012 [(a)] |
| U.S. Federal statutory rate | 35.0% | 35.0% | 35.0% |
| Increase (decrease) due to: | | | |
| State income taxes, net of Federal income tax benefit | 1.3 | 4.8 | (3.5) |
| Qualified nuclear decommissioning trust fund income | 2.4 | 3.7 | 5.4 |
| Tax exempt income | (0.2) | (0.2) | (0.2) |
| Domestic production activities deduction | (2.0) | — | — |
| Health care reform legislation | 0.1 | 0.1 | 0.1 |
| Amortization of investment tax credit, net deferred taxes | (1.1) | (1.9) | (1.1) |
| Plant basis differences | (1.9) | (1.6) | (2.4) |
| Production tax credits and other credits | (2.4) | (2.1) | (2.2) |
| Fines and Penalties | — | — | 2.6 |
| Merger expenses [(b)] | — | — | 2.4 |
| Non-controlling interest | (1.8) | — | — |
| Statute of limitations expiration | (2.6) | (0.1) | (0.1) |
| Other | — | (0.1) | (1.1) |
| Effective income tax rate | 26.8% | 37.6% | 34.9% |

(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) 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, 2014 and 2013 are presented below:

| | For the Year Ended December 31, | |
|---|---|---|
| | 2014 | 2013 |
| Plant basis differences | $(12,143) | $(11,612) |
| Accrual based contracts | (178) | (214) |
| Derivatives and other financial instruments | (46) | (509) |
| Deferred pension and postretirement obligation | 1,914 | 1,489 |
| Nuclear decommissioning activities | (726) | (647) |
| Deferred debt refinancing costs | 112 | 173 |
| Regulatory assets and liabilities | (1,824) | (1,611) |
| Tax loss carryforward | 111 | 252 |
| Tax credit carryforward | 97 | 534 |
| Investment in CENG | (563) | (541) |
| Other, net | 1,029 | 804 |
| Deferred income tax liabilities (net) | $(12,217) | $(11,882) |
| Unamortized investment tax credits | (555) | (490) |
| Total deferred income tax liabilities (net) and unamortized investment tax credits | $(12,772) | $(12,372) |

**Combined Notes to Consolidated Financial Statements—(Continued)**
**(Dollars in millions, except per share data unless otherwise noted)**

The following table provides Exelon's carryforwards and any corresponding valuation allowances as of December 31, 2014.

| | Exelon |
|---|---|
| **Federal** | |
| Federal general business credits carryforward | 184[(a)] |
| **State** | |
| State net operating losses and other credit carryforwards | 3,141[(b)] |
| Deferred taxes on state tax attributes (net) | 169 |
| Valuation allowance on state tax attributes | 50 |

(a) Exelon's federal general business credit carryforwards will expire beginning in 2032.
(b) Exelon's state net operating losses and other carryforwards, which are presented on a post-apportioned basis, will expire beginning in 2015.

***Tabular reconciliation of unrecognized tax benefits***

The following table provides a reconciliation of Exelon's unrecognized tax benefits as of December 31, 2014, 2013 and 2012:

| | |
|---|---|
| Unrecognized tax benefits at January 1, 2014 | $2,175 |
| Increases based on tax positions related to 2014 | 15 |
| Change to positions that only affect timing | (255) |
| Increases based on tax positions prior to 2014 | 18 |
| Decreases based on tax positions prior to 2014 | (1) |
| Decrease from settlements with taxing authorities | (35) |
| Decreases from expiration of statute of limitations | (88) |
| Unrecognized tax benefits at December 31, 2014 | $1,829 |
| Unrecognized tax benefits at January 1, 2013 | $1,024 |
| Increases based on tax positions related to 2013 | 19 |
| Change to positions that only affect timing | 649 |
| Increases based on tax positions prior to 2013 | 493 |
| Decreases based on tax positions prior to 2013 | (6) |
| Decreases from expiration of statute of limitations | (4) |
| Unrecognized tax benefits at December 31, 2013 | $2,175 |
| Unrecognized tax benefits at January 1, 2012 | $ 807 |
| Merger balance transfer | 195 |
| Increases based on tax positions related to 2012 | 34 |
| Change to positions that only affect timing | (88) |
| Increases based on tax positions prior to 2012 | 91 |
| Decreases based on tax positions prior to 2012 | (6) |
| Decreases related to settlements with taxing authorities | (2) |
| Decreases from expiration of statute of limitations | (7) |
| Unrecognized tax benefits at December 31, 2012 | $1,024 |

Included in Exelon's unrecognized tax benefits balance at December 31, 2014 and 2013 are approximately $1,129 million and $1,387 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

**Combined Notes to Consolidated Financial Statements—(Continued)**
**(Dollars in millions, except per share data unless otherwise noted)**

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 $701 million and $672 million, respectively, of unrecognized tax benefits at December 31, 2014 that, if recognized, would decrease the effective tax rate. Exelon and Generation had $788 million and $768 million, respectively, of unrecognized tax benefits at December 31, 2013 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*

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. In the first quarter of 2014, Exelon filed an appeal of the decision to the United States Court of Appeals for the Federal Circuit and oral arguments were heard in January of 2015.

Due to the possibility of final resolution through an appellate decision, Generation continues to believe that it is reasonably possible that the $661 million of total unrecognized tax benefits will significantly decrease in the next twelve months.

*Settlement of Income Tax Audits and Litigation*

As of December 31, 2014, Exelon and Generation have approximately $188 million of state unrecognized tax benefits that could significantly increase or decrease within the 12 months after the reporting date as a result of completing audits and expected statute of limitation expirations that if recognized would decrease the effective tax rate.

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 tax positions reflected in the Registrants' Consolidated Balance Sheets.

| Net interest receivable (payable) as of | Exelon | Generation | ComEd | PECO | BGE |
|---|---|---|---|---|---|
| December 31, 2014 | $(310) | $ 40 | $(203) | $3 | $ (1) |
| December 31, 2013 | (349) | (37) | (174) | 3 | — |

The following table sets forth the net interest expense, including interest related to tax positions, recognized in interest expense (income) in other income and deductions in the Registrants' Consolidated Statements of Operations and Comprehensive Income. The Registrants have not accrued any material penalties with respect to uncertain tax positions.

| Net interest expense (income) for the years ended | Exelon | Generation | ComEd | PECO | BGE |
|---|---|---|---|---|---|
| December 31, 2014 | $ (36) | $(50) | $ 6 | $— | $ 1 |
| December 31, 2013 | 391 | 17 | 281 | (1) | — |
| December 31, 2012 | (1) | 11 | (20) | (1) | 9 |

**Combined Notes to Consolidated Financial Statements—(Continued)**
**(Dollars in millions, except per share data unless otherwise noted)**

***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, 2001-2013 |
| Constellation and subsidiaries consolidated Federal income tax returns | 2011-March 2012 |
| Exelon and subsidiaries Illinois unitary income tax returns | 2007-2013 |
| Constellation combined New York corporate income tax returns | 2008-2013 |
| Various separate company Pennsylvania corporate net income tax returns | 2010-2013 |
| BGE Maryland corporate net income tax returns | 2011-2013 |
| Various Exelon Maryland corporate net income tax returns | 2012-2013 |
| Various Constellation (Non-BGE) Maryland corporate net income tax returns | 2011-2013 |

**Other Tax Matters**

***Like-Kind Exchange***

Exelon, through its ComEd subsidiary, took a position on its 1999 income tax return to defer approximately $1.2 billion of tax gain on the sale of ComEd's fossil generating assets. The gain was deferred by reinvesting a portion of 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 $1.2 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 $90 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 unpaid tax liabilities related to 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

**Combined Notes to Consolidated Financial Statements—(Continued)**
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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 IRS's assertion of penalties will ultimately be sustained and therefore no liability for the penalty has been recorded.

On September 30, 2013, the IRS 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.

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 as of December 31, 2014 may be as much as $810 million, of which approximately $310 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 and interest impacts will increase by a material amount.

In the first quarter of 2014, Exelon entered into an agreement to terminate its investment in one of the three municipal-owned electric generation properties in exchange for a net early termination amount of $335 million. The termination resulted in a 2014 tax payment of approximately $285 million by Exelon, including approximately $155 million by ComEd representing the remaining gain deferred pursuant to the like-kind exchange transaction. In the event of a fully successful IRS challenge to Exelon's like-kind exchange position, Exelon will be required to pay the full amount of tax and after-tax interest discussed in the preceding paragraph but will ultimately be entitled to a refund of the 2014 tax payment. See Note 8—Impairment of Long-Lived Assets for further details.

### *Accounting for Generation Repairs*

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 will change its method of accounting for deducting repairs in accordance with this guidance beginning with its 2014 tax year. Generation has calculated that adoption of the new method will result in a cash tax detriment of approximately $120 million.

### *Accounting for Electric Transmission and Distribution Property Repairs*

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 was reflected in the effective income tax rate reconciliation in 2011 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, and $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*

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

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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 determine the financial statement impacts of the gas distribution repair costs accounting method changes after guidance is issued.

***Accounting for Final Tangible Property Regulations***

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.

***Long-Term State Tax Apportionment***

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 2014 pursuant to Exelon's long-term state tax apportionment policy, resulting in the recording of a deferred state tax benefit for Exelon and Generation of $28 million (net of Federal taxes) and $40 million (net of Federal taxes), respectively. The amounts recorded for 2013 in accordance with the policy were immaterial.

***Allocation of Tax Benefits***

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 2014, Generation and PECO recorded an allocation of Federal tax benefits from Exelon under the Tax Sharing Agreement of $55 million and $25 million, respectively. ComEd and BGE did not record an allocation of Federal tax benefits from Exelon under the Tax Sharing Agreement as a result of tax net operating losses.

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 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 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 million, related to tax benefits associated with capital projects constructed by ComEd on behalf of Exelon and Generation.

**Combined Notes to Consolidated Financial Statements—(Continued)**
**(Dollars in millions, except per share data unless otherwise noted)**

### 15. Asset Retirement Obligations

***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.

The following table provides a rollforward of the nuclear decommissioning ARO reflected on Exelon's Consolidated Balance Sheets, from January 1, 2013 to December 31, 2014:

| | |
|---|---|
| Nuclear decommissioning ARO at January 1, 2013 | $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 |
| Consolidation of CENG [(b)] | 1,760 |
| Accretion expense | 334 |
| Net increase due to changes in, and timing of, estimated future cash flows | 19 |
| Costs incurred to decommission retired plants | (7) |
| Nuclear decommissioning ARO at December 31, 2014 [(a)] | $6,961 |

(a) Includes $8 million and $9 million as the current portion of the ARO at December 31, 2014 and 2013, respectively, which is included in Other current liabilities on Exelon's Consolidated Balance Sheets.
(b) Represents the fair value of the CENG ARO liability as of April 1, 2014, the date of consolidation. See Note 5—Investment in Constellation Energy Nuclear Group, LLC for additional information.

During 2014, Generation's ARO increased by approximately $2.1 billion. The increase is largely driven by the recording of an ARO on Exelon's Consolidated Balance Sheets at fair value, including subsequent purchase accounting adjustments, upon consolidation of CENG (see Note 5—Investment in Constellation Energy Nuclear Group, LLC ). The change in the ARO was also driven by an increase for accretion of the obligation and an increase in the estimated costs to decommission Byron, Braidwood, and LaSalle nuclear units resulting from the completion of updated decommissioning costs studies received during 2014 as part of the annual assessment. These increases in the ARO were partially offset by decreases in the ARO due to a reduction in estimated escalation rates, primarily for labor and energy costs. The increase in the ARO due to the changes in, and timing of, estimated cash flows was offset within Property, plant and equipment on Exelon's Consolidated Balance Sheets, aside from an approximate $16 million credit to income, which is included in Operating and maintenance expense within Exelon's Consolidated Statements of Operations and Comprehensive Income.

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 was entirely offset by decreases in Property, plant and equipment within Exelon's Consolidated Balance Sheets.

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

***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 Generation's nuclear units have been funded with amounts collected from the previous owners and their respective utility customers. 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 former PECO 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. Aside from the former PECO units, Generation does not currently collect any amounts, nor is there any mechanism by which Generation can seek to collect additional amounts, from utility customers. Apart from the contributions made to the NDT funds from amounts previously collected from ComEd and currently collected from PECO customers, Generation has not made contributions to the NDT funds.

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) and the CENG units, where any shortfall is required to be funded by both Generation and EDF. Generation, through PECO, 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, compared to decommissioning costs, as well as 5% of any additional shortfalls, on an aggregate basis for all former PECO units. The initial $50 million and up to 5% of any additional shortfalls, would be borne by Generation. No recourse exists to collect additional amounts for any of Generation's other nuclear 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 Generation's other nuclear units, Generation retains any funds remaining after decommissioning. However, in connection with CENG's acquisition of the Nine Mile Point and Ginna plants and settlements with certain regulatory agencies, CENG is subject to certain conditions pertaining to nuclear decommissioning trust funds that, if met, could possibly result in obligations to make payments to certain third parties (clawbacks). For Nine Mile Point and Ginna, the clawback provisions are triggered only in the event that the required decommissioning activities are discontinued or not started or completed in a timely manner. In the event that the clawback provisions are triggered for Nine Mile Point, then, depending upon the triggering event, an amount equal to 50% of the total amount withdrawn from the funds for non-decommissioning activities or 50% of any excess funds in the trust funds above the amounts required for decommissioning (including spent fuel management and decommissioning) is to be paid to the Nine Mile Point sellers. In the event that the clawback provisions are triggered for Ginna, then an amount equal to any estimated cost savings realized by not completing any of the required decommissioning activities is to be paid to the Ginna sellers. Generation expects to comply with applicable regulations and timely commence and complete all required decommissioning activities.

At December 31, 2014, and 2013, Exelon had NDT fund investments totaling $10,537 million and $8,071 million, respectively. At December 31, 2014, approximately 52% of the funds were invested in equity securities and 48% were invested in fixed income securities. At December 31, 2013, approximately 48% of the funds were invested in equity securities and 52% were invested in fixed income securities. 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.

**Combined Notes to Consolidated Financial Statements—(Continued)**
**(Dollars in millions, except per share data unless otherwise noted)**

The following table provides unrealized gains on NDT funds for 2014, 2013 and 2012:

| | For the Years Ended December 31, | | |
|---|---|---|---|
| | 2014 | 2013 | 2012 |
| Net unrealized gains on decommissioning trust funds—Regulatory Agreement Units [(a)] | $180 | $406 | $386 |
| Net unrealized gains on decommissioning trust funds—Non-Regulatory Agreement Units [(b)(c)] | 134 | 146 | 105 |

(a) Net unrealized gains related to Generation's NDT funds associated with Regulatory Agreement Units are included in Regulatory liabilities on Exelon's Consolidated Balance Sheets.
(b) Excludes $29 million, $7 million and $73 million of net unrealized gains related to the Zion Station pledged assets in 2014, 2013 and 2012, respectively. Net unrealized gains related to Zion Station pledged assets are included in the Payable for Zion Station decommissioning on Exelon's Consolidated Balance Sheets.
(c) Net unrealized gains related to Generation's NDT funds with Non-Regulatory Agreement Units are included within Other, net in Exelon'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 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 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, 2014, the NDT funds of each of the former ComEd units, except for Zion (see Zion Station Decommissioning below), 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 former PECO 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 Non-Regulatory Agreement Units are reflected in Exelon's Consolidated Statements of Operations and Comprehensive Income.

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.

**Combined Notes to Consolidated Financial Statements—(Continued)**
**(Dollars in millions, except per share data unless otherwise noted)**

***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 and decommission the SNF dry storage facility, 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 its 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.

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 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 for Zion Station decommissioning 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 for the SNF. Following ZionSolutions' completion of its contractual obligations and transfer of the NRC license to Generation, Generation will store the SNF at Zion Station until it is transferred to the DOE for ultimate disposal, and will complete all remaining decommissioning activities associated with the SNF dry storage facility. Generation has a liability of approximately $86 million, which is included within the nuclear decommissioning ARO at December 31, 2014. Generation also has retained NDT assets to fund its obligation to maintain the SNF at Zion Station until transfer to the DOE 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 payables to ZionSolutions, and withdrawals by ZionSolutions at December 31, 2014 and 2013:

| | 2014 | 2013 |
|---|---|---|
| Carrying value of Zion Station pledged assets | $319 | $458 |
| Payable to Zion Solutions [(a)] | 292 | 414 |
| Current portion of payable to Zion Solutions [(b)] | 137 | 109 |
| Cumulative withdrawals by Zion Solutions to pay decommissioning costs | 666 | 498 |

(a) Excludes a liability recorded within Exelon'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 Consolidated Balance Sheets.

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 constructed a dry cask storage facility on the land and has loaded the SNF from the SNF pools onto the dry cask storage facility 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 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 and its parent company have also provided a performance guarantee and EnergySolutions has 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.

**Combined Notes to Consolidated Financial Statements—(Continued)**
**(Dollars in millions, except per share data unless otherwise noted)**

***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 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, 2014 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, 2014 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 6% to 6.3% (as compared to a historical 5-year annual average pre-tax return of approximately 9%).

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 had 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 March 26, 2014, in accordance with a NRC requirement with respect to units involved in a merger or acquisition, CENG submitted its NRC-required decommissioning funding status report as of December 31, 2013 and no additional financial assurance was required.

On March 31, 2014, Generation submitted its NRC required annual decommissioning funding report as of December 31, 2013 for reactors that have been shut down except for Zion Station which is included on a separate report to the NRC submitted by EnergySolutions (see Zion Station Decommissioning above). This submittal also included the required updated financial tests for the Limerick Unit 1 parent guarantee. There was no change to the amount of the parent guarantee, or the funding status of these reactors. Adequate decommissioning funding assurance is in place for all reactors owned by Generation. During 2014, the operating license for Limerick Unit 1 was extended by 20 years. As a result of this extension, and the subsequent funding assurance calculation performed by the NRC, it was found that the parent company guarantee was no longer required and thus the parent guarantee for Limerick Unit 1 will be cancelled effective March 13, 2015. See Note 3—Regulatory Matters for additional information regarding the operating license extension for Limerick Unit 1.

Generation will file its next biennial decommissioning funding status report with the NRC on or before March 31, 2015. That report will reflect the status of decommissioning funding assurance as of December 31, 2014. Due to increased cost estimates received in the second half of 2014, Braidwood Unit 1, Braidwood Unit 2, and Byron Unit 2 do not have adequate funding assurance based on the most recent calculations as of December 31, 2014. NRC guidance provides licensees with two years or by the time of submitting the next biennial report (on or before March 31, 2017) to resolve funding assurance shortfalls. During this period, Generation will monitor funding assurance and new developments, including the impact of a 20-year license renewal for Braidwood and Byron, to assess the status of funding assurance and to take steps, if necessary, to address any funding shortfall on these funds on or before March 31, 2017.

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. The January 31, 2013 letter from the NRC does not take issue with 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. 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. On May 1, 2014, the NRC issued its final determination. Although the NRC determined that these historical status reports did not provide complete and accurate information, the violation of the regulatory requirements was not a deliberate violation. The NRC noted the low safety significance and Generation's corrective actions to satisfy the NRC Staff's expectations and issued a Severity Level IV violation, with no monetary penalty. A Severity Level IV violation is the lowest level of violation.

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 Generation's nuclear power plants. Exelon and Generation have cooperated with the SEC and provided the requested documents. On February 13, 2014, Exelon received a letter from the SEC confirming that it had concluded its investigation and that no further action was anticipated based on information provided by Exelon.

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 units, the NRC minimum funding status of those plants could change at subsequent NRC filing dates.

### Non-Nuclear Asset Retirement Obligations

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.

**Combined Notes to Consolidated Financial Statements—(Continued)**
**(Dollars in millions, except per share data unless otherwise noted)**

The following table provides a rollforward of the non-nuclear AROs reflected on the Exelon's Consolidated Balance Sheets from January 1, 2013 to December 31, 2014:

| | |
|---|---|
| Non-nuclear AROs at January 1, 2013 | $343 |
| Net increase (decrease) due to changes in, and timing of, estimated future cash flows [(a)] | 1 |
| Development projects [(b)] | 2 |
| Accretion expense [(c)] | 18 |
| Payments | (13) |
| Non-nuclear AROs at December 31, 2013 [(d)] | 351 |
| Net increase (decrease) due to changes in, and timing of, estimated future cash flows [(a)] | (1) |
| Development projects [(b)] | 11 |
| Accretion expense [(c)] | 15 |
| Liabilities held for sale [(e)] | (4) |
| Sale of generating assets [(f)] | (20) |
| Payments | (6) |
| Non-nuclear AROs at December 31, 2014 [(d)] | $346 |

(a) During the year ended December 31, 2014, Generation recorded a decrease of $(2) million and ComEd recorded an increase of $1 million in Operating and maintenance expense. PECO, and BGE did not record any adjustments in Operating and maintenance expense for the year ended December 31, 2014. During the year ended December 31, 2013, Generation recorded an increase in Operating and maintenance expense of $13 million. ComEd, PECO, and BGE did not record any adjustments in Operating and maintenance expense for the year ended December 31, 2013.
(b) Relates to new AROs recorded due to the construction of solar, wind and other non-nuclear generating sites.
(c) 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.
(d) During the year ended December 31, 2014, Generation, ComEd, PECO and BGE recorded $1 million, $1 million, $1 million, and $1 million, respectively, as the current portion of the ARO. During December 31, 2013 Generation, ComEd, PECO and BGE recorded $0 million, $2 million, $1 million, and $0 million, respectively, as the current portion of the ARO. This is included in Other current liabilities on the Registrants' respective Consolidated Balance Sheets.
(e) Represents AROs related to generating stations classified as held for sale as of December 31, 2014. See Note 4—Mergers, Acquisitions, and Dispositions for further information.
(f) Reflects a reduction to the ARO resulting primarily from the sales of the Keystone and Conemaugh generating stations. See Note 4—Mergers, Acquisitions, and Dispositions for further information.

## 16. Retirement Benefits

As of December 31, 2014, Exelon sponsored defined benefit pension plans and other postretirement benefit plans for essentially all Generation, ComEd, PECO, BGE and BSC employees. The table below shows the pension and postretirement benefit plans in which each operating company participated at December 31, 2014.

On April 1, 2014, as a result of the consolidation of CENG into Generation, the obligations associated with CENG's pension and other postretirement plans are reflected in the disclosures below based on an April 1, 2014 valuation adjusted for subsequent activity. Exelon assumed sponsorship of the CENG pension and other postretirement benefit plans in the third quarter of 2014 when the employees transferred to Exelon. CENG will fund the underfunded balances of the pension and other postretirement benefit plans measured at July 14, 2014 on an agreed payment schedule or upon the occurrence of certain specified events, such as EDF's disposition of a majority of its interest in CENG. Payments received from CENG related to the funded plans will be contributed to the appropriate benefit trusts.

### *Benefit Obligations, Plan Assets and Funded Status*

Exelon recognizes the overfunded or underfunded status of defined benefit pension and OPEB 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 2014, Exelon received an updated valuation of its legacy pension and other postretirement benefit obligations to reflect actual census data as of January 1, 2014. This valuation resulted in an increase to the pension obligation of $35 million and an increase to the other postretirement benefit obligation of $12 million. Additionally, Accumulated other comprehensive loss (AOCL) increased by approximately $12 million (after tax), regulatory assets increased by approximately $34 million, and

**Combined Notes to Consolidated Financial Statements—(Continued)**
**(Dollars in millions, except per share data unless otherwise noted)**

regulatory liabilities increased by approximately $5 million. During the second quarter of 2014, Exelon received an updated valuation for the remainder of its pension and other postretirement obligations to reflect actual census data as of January 1, 2014. This valuation resulted in an increase to the pension obligation of $13 million and an increase to the other postretirement benefit obligation of $3 million. Additionally, AOCL increased by approximately $1 million (after tax) and regulatory assets increased by approximately $15 million.

In April 2014, Exelon announced plan design changes for certain other postretirement benefit plans, which required an interim remeasurement of the benefit obligation for those plans using assumptions as of April 30, 2014, including updated discount rates and asset values. The remeasurement resulted in a decrease to Exelon's non-pension postretirement benefit obligations, regulatory assets, and AOCL of approximately $790 million, $240 million, and $259 million (after tax), respectively, and an increase in regulatory liabilities of approximately $125 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 | |
|---|---|---|---|---|
| | 2014 | 2013 | 2014 | 2013 |
| Change in benefit obligation: | | | | |
| Net benefit obligation at beginning of year | $15,459 | $16,800 | $ 4,451 | $4,820 |
| Service cost | 293 | 317 | 117 | 162 |
| Interest cost | 749 | 650 | 186 | 194 |
| Plan participants' contributions | — | — | 42 | 34 |
| Actuarial loss (gain) | 2,095 | (1,363) | 502 | (551) |
| Plan amendments | — | 1 | (1,012) | 15 |
| Acquisitions/divestitures [(a)] | 594 | — | 142 | — |
| Curtailments | (8) | — | — | — |
| Settlements | (30) | (69) | — | — |
| Gross benefits paid | (896) | (877) | (231) | (223) |
| Net benefit obligation at end of year | $18,256 | $15,459 | $ 4,197 | $4,451 |

| | Pension Benefits | | Other Postretirement Benefits | |
|---|---|---|---|---|
| | 2014 | 2013 | 2014 | 2013 |
| Change in plan assets: | | | | |
| Fair value of net plan assets at beginning of year | $13,571 | $13,357 | $2,238 | $2,135 |
| Actual return on plan assets | 1,443 | 821 | 90 | 209 |
| Employer contributions | 332 | 339 | 291 | 83 |
| Plan participants' contributions | — | — | 42 | 34 |
| Benefits paid | (896) | (877) | (231) | (223) |
| Acquisitions/divestitures [(a)] | 454 | — | — | — |
| Settlements | (30) | (69) | — | — |
| Fair value of net plan assets at end of year | $14,874 | $13,571 | $2,430 | $2,238 |

(a) On April 1, 2014, Generation assumed operational control of CENG's nuclear fleet. As a result, Exelon became a sponsor of CENG's pension and OPEB plans effective July 14, 2014. See Note 5—Investment in Constellation Energy Nuclear Group, LLC for further information.

**Combined Notes to Consolidated Financial Statements—(Continued)**
**(Dollars in millions, except per share data unless otherwise noted)**

Exelon presents its benefit obligations and plan assets net on its balance sheet within the following line items:

| | Pension Benefits | | Other Postretirement Benefits | |
|---|---|---|---|---|
| | 2014 | 2013 | 2014 | 2013 |
| Other current liabilities | $ 16 | $ 12 | $ 25 | $ 23 |
| Pension obligations | 3,366 | 1,876 | — | — |
| Non-pension postretirement benefit obligations | — | — | 1,742 | 2,190 |
| Unfunded status (net benefit obligation less net plan assets) | $3,382 | $1,888 | $1,767 | $2,213 |

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 | |
|---|---|---|
| | 2014 | 2013 |
| Projected benefit obligation | $18,256 | $15,452 |
| Fair value of net plan assets | 14,874 | 13,564 |

| | ABO in excess of plan assets | |
|---|---|---|
| | 2014 | 2013 |
| Projected benefit obligation | $18,256 | $15,452 |
| Accumulated benefit obligation | 17,191 | 14,552 |
| Fair value of net plan assets | 14,874 | 13,564 |

On a PBO basis, the plans were funded at 81% at December 31, 2014 compared to 88% at December 31, 2013. On an ABO basis, the plans were funded at 87% at December 31, 2014 compared to 93% at December 31, 2013. The ABO differs from the PBO in that the ABO includes no assumption about future compensation levels.

### *Components of Net Periodic Benefit Costs*

The majority of the 2014 pension benefit cost for Exelon-sponsored plans is calculated using an expected long-term rate of return on plan assets of 7.00% and a discount rate of 4.80%. Certain of the pension plans were remeasured as of October 31, 2014 using an expected long-term rate of return on plan assets of 7.00% and a discount rate of 3.95%. Costs incurred during the year ended December 31, 2014 reflect the impact of this remeasurement. The majority of the 2014 other postretirement benefit cost is calculated using an expected long-term rate of return on plan assets of 6.59% for funded plans and a discount rate of 4.90% for all plans. Certain of the other postretirement benefit plans were remeasured as of April 30, 2014 using an expected long-term rate of return on plan assets of 6.59% and a discount rate of 4.30%. Costs for December 31, 2014 reflect the impact of this remeasurement.

On July 14, 2014 Exelon became the sponsor of the pension and other postretirement plans formerly sponsored by CENG. The components of cost for the CENG plans are included in the table below for the period from April 1, 2014 to December 31, 2014, and reflect the valuation performed on April 1, 2014 upon consolidation of CENG. Refer to Note 5—Investment in Constellation Energy Nuclear Group, LLC for further details on the consolidation of CENG. The 2014 pension benefit cost for these plans is calculated using an expected long-term rate of return on plan assets of 7.75% and discount rates ranging from 3.60%—4.30%. The majority of the 2014 other postretirement benefit cost for the CENG plans is calculated using a discount rate of 4.55%.

**Combined Notes to Consolidated Financial Statements—(Continued)**
**(Dollars in millions, except per share data unless otherwise noted)**

A portion of the net periodic benefit cost for all pension and OPEB plans are capitalized within each of the Registrant's Consolidated Balance Sheets. The following table presents the components of Exelon's net periodic benefit costs, prior to any capitalization, for the years ended December 31, 2014, 2013 and 2012.

| | Pension Benefits | | | Other Postretirement Benefits | | |
|---|---|---|---|---|---|---|
| | 2014 | 2013 | 2012 | 2014 | 2013 | 2012 |
| **Components of net periodic benefit cost:** | | | | | | |
| Service cost | $ 293 | $ 317 | $ 280 | $ 117 | $ 162 | $ 156 |
| Interest cost | 749 | 650 | 698 | 186 | 194 | 205 |
| Expected return on assets | (994) | (1,015) | (988) | (154) | (132) | (115) |
| Amortization of: | | | | | | |
| Transition obligation | — | — | — | — | — | 11 |
| Prior service cost (credit) | 14 | 14 | 15 | (122) | (19) | (17) |
| Actuarial loss | 420 | 562 | 450 | 50 | 83 | 81 |
| Curtailment benefits | — | — | — | — | — | (7) |
| Settlement charges | 2 | 9 | 31 | — | — | — |
| Contractual termination benefits [(a)] | — | — | 14 | — | — | 6 |
| **Net periodic benefit cost** | $ 484 | $ 537 | $ 500 | $ 77 | $ 288 | $ 320 |

(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 Prescription Drug, Improvement and Modernization Act of 2003 (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 (Part D subsidy). 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 would no longer elect to take the direct Part D subsidy. This resulted in a $17 million increase in cost for the year ended December 31, 2012 related to the amortization of an actuarial loss. Beginning in 2013, eligible employees are offered an Employee Group Waiver Plan (EGWP), a standard Medicare Part D Plan, with a supplemental "wrap," which contains a wraparound prescription drug design that allows the company to provide benefits above those available under the EGWP.

**Combined Notes to Consolidated Financial Statements—(Continued)**
**(Dollars in millions, except per share data unless otherwise noted)**

***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, 2014, 2013 and 2012 for all plans combined.

| | Pension Benefits | | | Other Postretirement Benefits | | |
|---|---|---|---|---|---|---|
| | 2014 | 2013 | 2012 | 2014 | 2013 | 2012 |
| **Changes in plan assets and benefit obligations recognized in AOCI and regulatory assets (liabilities):** | | | | | | |
| Current year actuarial (gain) loss | $1,639 | $(1,169) | $1,693 | $ 561 | $(628) | $ 304 |
| Amortization of actuarial loss | (420) | (562) | (450) | (50) | (83) | (81) |
| Current year prior service (credit) cost | — | — | 1 | (1,012) | 15 | (109) |
| Amortization of prior service (cost) credit | (14) | (14) | (15) | 122 | 19 | 17 |
| Current year transition (asset) obligation | — | — | — | — | — | 1 |
| Amortization of transition asset (obligation) | — | — | — | — | — | (11) |
| Curtailments | — | — | (10) | — | — | (1) |
| Settlements | (2) | (8) | (31) | — | — | — |
| **Total recognized in AOCI and regulatory assets (liabilities)** [(a)] | $1,203 | $(1,753) | $1,188 | $ (379) | $(677) | $ 120 |

(a) Of the $1,203 million loss related to pension benefits, $788 million and $415 million were recognized in AOCI and regulatory assets, respectively, during 2014. Of the $379 million gain related to other postretirement benefits, $162 million and $217 million were recognized in AOCI and regulatory assets (liabilities), respectively, during 2014. 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.

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, 2014 and 2013, respectively, for all plans combined:

| | Pension Benefits | | Other Postretirement Benefits | |
|---|---|---|---|---|
| | 2014 | 2013 | 2014 | 2013 |
| Prior service cost (credit) | $ 49 | $ 62 | $(963) | $ (73) |
| Actuarial loss | 7,407 | 6,192 | 985 | 474 |
| Total [(a)] | $7,456 | $6,254 | $ 22 | $401 |

(a) Of the $7,456 million related to pension benefits, $4,310 million and $3,146 million are included in AOCI and regulatory assets, respectively, at December 31, 2014. Of the $22 million related to other postretirement benefits, $22 million is included in regulatory assets (liabilities) at December 31, 2014. 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.

**Combined Notes to Consolidated Financial Statements—(Continued)**
**(Dollars in millions, except per share data unless otherwise noted)**

The following table provides the components of Exelon's AOCI and regulatory assets at December 31, 2014 (included in the table above) that are expected to be amortized as components of periodic benefit cost in 2015. 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, 2015 and actual claims activity as of December 31, 2014. The valuation is expected to be completed in the first quarter of 2015 for the majority of the benefit plans.

| | Pension Benefits | Other Postretirement Benefits |
|---|---|---|
| Prior service cost (credit) | $ 13 | $(175) |
| Actuarial loss | 562 | 74 |
| Total [(a)] | $575 | $(101) |

(a) Of the $575 million related to pension benefits at December 31, 2014, $329 million and $246 million are expected to be amortized from AOCI and regulatory assets in 2015, respectively. Of the $101 million related to other postretirement benefits at December 31, 2014, $(51) million and $(50) million are expected to be amortized from AOCI and regulatory assets (liabilities) in 2015, 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 EROA, 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.

*Expected Rate of Return.* In selecting the EROA, 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.

*Mortality.* For the December 31, 2014 actuarial valuation, Exelon changed its assumption of mortality to reflect more recent expectations of future improvements in life expectancy. The change was supported through completion of an experience study and supplemental analyses performed by its actuaries. The change in assumption resulted in increases of $361 million and $117 million in the pension and other postretirement benefits obligations, respectively.

**Combined Notes to Consolidated Financial Statements—(Continued)**
**(Dollars in millions, except per share data unless otherwise noted)**

The following assumptions were used to determine the benefit obligations for the plans at December 31, 2014, 2013 and 2012. 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 | | |
|---|---|---|---|---|---|---|
| | 2014 | 2013 | 2012 | 2014 | 2013 | 2012 |
| Discount rate | 3.94% | 4.80% | 3.92% | 3.92% | 4.90% | 4.00% |
| Rate of compensation increase | (a) | (b) | (c) | (a) | (b) | (c) |
| Mortality table | RP-2000 table with Scale BB-2D improvements (adjusted) | RP-2000 table with Scale AA improvements | RP-2000 table with Scale AA improvements | RP-2000 table with Scale BB-2D improvements (adjusted) | RP-2000 table with Scale AA improvements | RP-2000 table with Scale AA improvements |
| Health care cost trend on covered charges | N/A | N/A | N/A | 6.00% decreasing to ultimate trend of 5.00% in 2017 | 6.00% decreasing to ultimate trend of 5.00% in 2017 | 6.50% decreasing to ultimate trend of 5.00% in 2017 |

(a) 3.25% for 2015-2019 and 3.75% thereafter.
(b) 3.25% for 2014-2018 and 3.75% thereafter.
(c) 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, 2014, 2013 and 2012:

| | Pension Benefits | | | Other Postretirement Benefits | | |
|---|---|---|---|---|---|---|
| | 2014 | 2013 | 2012 | 2014 | 2013 | 2012 |
| Discount rate | 4.80%(a) | 3.92%(b) | 4.74%(c) | 4.90%(a) | 4.00%(b) | 4.80%(c) |
| Expected return on plan assets | 7.00%(d) | 7.50%(d) | 7.50%(d) | 6.59%(d) | 6.45%(d) | 6.68%(d) |
| Rate of compensation increase | (e) | (f) | 3.75% | (e) | (f) | 3.75% |
| Mortality table | RP-2000 table with Scale AA improvements | RP-2000 table with Scale AA improvements | RP-2000 table with Scale AA improvements | RP-2000 table with Scale AA improvements | RP-2000 table with Scale AA improvements | RP-2000 table with Scale AA improvements |
| 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) The discount rates above represent the initial discount rates used to establish the majority of Exelon's pension and other postretirement benefits costs for the year ended December 31, 2014. Certain of the other postretirement benefit plans were remeasured as of April 30, 2014 using an expected long-term rate of return on plan assets of 6.59% and a discount rate of 4.30%. Costs for the year ended December 31, 2014 reflect the impact of this remeasurement. On April 1, 2014, Generation assumed operational control of CENG's nuclear fleet. As a result, Exelon became the sponsor of CENG's legacy pension and OPEB plans effective July 14, 2014; discount rates for those plans, impacting 2014 costs, ranged from 3.60%-4.30% and 4.09%-4.55%, respectively. See Note 5—Investment in Constellation Energy Nuclear Group, LLC for further information.
(b) 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 measurements.
(c) The discount rates above represent the initial discounts rates used to establish Exelon's pension and other postretirement benefits costs for the year ended December 31, 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.
(d) Not applicable to pension and other postretirement benefit plans that do not have plan assets.
(e) 3.25% for 2014-2018 and 3.75% thereafter.
(f) 3.25% for 2013-2017 and 3.75% thereafter.

**Combined Notes to Consolidated Financial Statements—(Continued)**
**(Dollars in millions, except per share data unless otherwise noted)**

Assumed health care cost trend rates impact the costs reported for Exelon's other postretirement benefit plans for participants populations with plan designs that do not have a cap on cost growth. 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 2014 total service and interest cost components | $ 35 |
| on postretirement benefit obligation at December 31, 2014 | 162 |
| Effect of a one percentage point decrease in assumed health care cost trend: | |
| on 2014 total service and interest cost components | (24) |
| on postretirement benefit obligation at December 31, 2014 | (113) |

***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 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.

***Contributions***

The following table provides contributions made by Exelon to the pension and other postretirement benefit plans:

| | Pension Benefits | | | Other Postretirement Benefits | | |
|---|---|---|---|---|---|---|
| | 2014 [(b)] | 2013 | 2012 | 2014 | 2013 | 2012 [(a)] |
| Exelon | $332 | $339 | $149 | $291 | $83 | $323 |

(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, received Federal subsidy payments of $10 million, in 2012. Effective January 1, 2013, Exelon is no longer receiving this subsidy.
(b) Exelon's pension contributions include $43 million related to the legacy CENG plans that was funded by CENG as provided in an Employee Matters Agreement (EMA) between Exelon and CENG.

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, until the plan is fully funded on an ABO basis, the projected contribution reflects a funding strategy of contributing $250 million. This level funding strategy helps minimize volatility of future period required pension contributions.

Exelon plans to contribute $447 million to its qualified pension plans in 2015, of which Generation, ComEd, PECO, and BGE will contribute $230 million, $138 million, $40 million, and $1 million, respectively. Exelon's and Generation's expected qualified pension plan contributions above include $36 million related to the legacy CENG plans that will be funded by CENG as provided in an EMA between Exelon and CENG.

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 $15 million in 2015, of which Generation, ComEd, PECO, and BGE will make payments of $6 million, $1 million, $1 million and $1 million, respectively.

**Combined Notes to Consolidated Financial Statements—(Continued)**
**(Dollars in millions, except per share data unless otherwise noted)**

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 2015, 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 $37 million in 2015, of which Generation, ComEd, PECO, and BGE expect to contribute $17 million, $2 million, $0 million, and $17 million, respectively.

***Estimated Future Benefit Payments***

Estimated future benefit payments to participants in all of the pension plans and postretirement benefit plans at December 31, 2014 were:

| | Pension Benefits | Other Postretirement Benefits |
|---|---|---|
| 2015 | $ 1,064 | $ 217 |
| 2016 | 962 | 223 |
| 2017 | 979 | 230 |
| 2018 | 1,004 | 236 |
| 2019 | 1,032 | 247 |
| 2020 through 2024 | 5,825 | 1,373 |
| Total estimated future benefit payments through 2024 | $10,866 | $2,526 |

***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 6.46% to estimate its 2015 pension and other postretirement benefit costs, respectively.

Exelon's pension and other postretirement benefit plan target asset allocations and December 31, 2014 and 2013 asset allocations were as follows:

**Pension Plans**

| Asset Category | Target Allocation | Percentage of Plan Assets at December 31, 2014 | 2013 |
|---|---|---|---|
| Equity securities | 32% | 33% | 35% |
| Fixed income securities | 37% | 37 | 37 |
| Alternative investments [(a)] | 31% | 30 | 28 |
| Total | | 100% | 100% |

**Combined Notes to Consolidated Financial Statements—(Continued)**
**(Dollars in millions, except per share data unless otherwise noted)**

**Other Postretirement Benefit Plans**

| Asset Category | Target Allocation | Percentage of Plan Assets at December 31, 2014 | 2013 |
|---|---|---|---|
| Equity securities | 41% | 42% | 45% |
| Fixed income securities | 34% | 34 | 37 |
| Alternative investments [(a)] | 25% | 24 | 18 |
| Total | | 100% | 100% |

(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, 2014. 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, 2014, there were no significant concentrations (defined as greater than 10% of plan assets) of risk in Exelon's pension and other postretirement benefit plan assets.

**Combined Notes to Consolidated Financial Statements—(Continued)**
**(Dollars in millions, except per share data unless otherwise noted)**

***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, 2014 and 2013:

| At December 31, 2014 [a] | Level 1 | Level 2 | Level 3 | Total |
|---|---|---|---|---|
| **Pension plan assets** | | | | |
| Cash equivalents | $ 1 | $ — | $ — | $ 1 |
| Equities: | | | | |
| Domestic | 1,556 | 1,133 | 2 | 2,691 |
| Foreign | 1,705 | 316 | — | 2,021 |
| Equities subtotal | 3,261 | 1,449 | 2 | 4,712 |
| Fixed income: | | | | |
| Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies | 1,051 | 88 | — | 1,139 |
| Debt securities issued by states of the United States and by political subdivisions of the states | — | 80 | — | 80 |
| Corporate debt securities | — | 3,125 | 120 | 3,245 |
| Other | — | 942 | 152 | 1,094 |
| Derivative instruments [b]: | | | | |
| Assets | — | 4 | — | 4 |
| Liabilities | — | (16) | — | (16) |
| Fixed income subtotal | 1,051 | 4,223 | 272 | 5,546 |
| Private equity | — | — | 904 | 904 |
| Hedge funds | — | 1,355 | 1,329 | 2,684 |
| Real estate | 243 | — | 744 | 987 |
| **Pension plan assets subtotal** | 4,556 | 7,027 | 3,251 | 14,834 |

| At December 31, 2014 [a] | Level 1 | Level 2 | Level 3 | Total |
|---|---|---|---|---|
| **Other postretirement benefit plan assets** | | | | |
| Cash equivalents | 11 | — | — | 11 |
| Equities: | | | | |
| Domestic | 296 | 378 | — | 674 |
| Foreign | 184 | 147 | — | 331 |
| Equities subtotal | 480 | 525 | — | 1,005 |
| Fixed income: | | | | |
| Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies | 15 | 59 | — | 74 |
| Debt securities issued by states of the United States and by political subdivisions of the states | — | 197 | — | 197 |
| Corporate debt securities | — | 42 | — | 42 |
| Other | 253 | 272 | — | 525 |
| Fixed income subtotal | 268 | 570 | — | 838 |
| Hedge funds | — | 339 | 110 | 449 |
| Real estate | 8 | — | 116 | 124 |
| **Other postretirement benefit plan assets subtotal** | 767 | 1,434 | 226 | 2,427 |
| **Total pension and other postretirement benefit plan assets** [c] | $5,323 | $8,461 | $3,477 | $17,261 |

**Combined Notes to Consolidated Financial Statements—(Continued)**
**(Dollars in millions, except per share data unless otherwise noted)**

| At December 31, 2013 [a] | Level 1 | Level 2 | Level 3 | Total |
|---|---|---|---|---|
| **Pension plan assets** | | | | |
| Equities: | | | | |
| Domestic | $1,587 | $ 865 | $ 2 | $ 2,454 |
| Foreign | 1,773 | 302 | — | 2,075 |
| Equities subtotal | 3,360 | 1,167 | 2 | 4,529 |
| Fixed income: | | | | |
| Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies | 908 | 99 | — | 1,007 |
| 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 |
| Other | 5 | 899 | — | 904 |
| Derivative instruments [b]: | | | | |
| Assets | — | 7 | — | 7 |
| Liabilities | — | (134) | — | (134) |
| Fixed income subtotal | 913 | 4,091 | 41 | 5,045 |
| Private equity | — | — | 806 | 806 |
| Hedge funds | — | 1,266 | 1,039 | 2,305 |
| Real estate | 264 | 2 | 582 | 848 |
| **Pension plan assets subtotal** | 4,537 | 6,526 | 2,470 | 13,533 |

| At December 31, 2013 [a] | Level 1 | Level 2 | Level 3 | Total |
|---|---|---|---|---|
| **Other postretirement benefit plan assets** | | | | |
| Cash equivalents | 51 | — | — | 51 |
| Equities: | | | | |
| Domestic | 296 | 345 | — | 641 |
| Foreign | 154 | 170 | — | 324 |
| Equities subtotal | 450 | 515 | — | 965 |
| Fixed income: | | | | |
| Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies | 17 | 46 | — | 63 |
| 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 |
| Other | 305 | 225 | — | 530 |
| Fixed income subtotal | 322 | 472 | — | 794 |
| Private equity | — | — | 2 | 2 |
| Hedge funds | — | 295 | 4 | 299 |
| Real estate | 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 |

(a) See Note 11—Fair Value of Financial Assets and Liabilities for a description of levels within the fair value hierarchy.
(b) Derivative instruments have a total notional amount of $1,491 million and $2,651 million at December 31, 2014 and 2013, 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 $42 million and $43 million at December 31, 2014 and 2013, 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.

**Combined Notes to Consolidated Financial Statements—(Continued)**
**(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, 2014 and 2013:

| | Hedge funds | Private equity | Real estate | Fixed income | Equities | Total |
|---|---|---|---|---|---|---|
| **Pension Assets** | | | | | | |
| Balance as of January 1, 2014 | $1,039 | $ 806 | $582 | $ 41 | $ 2 | $2,470 |
| Actual return on plan assets: | | | | | | |
| Relating to assets still held at the reporting date | 77 | 112 | 83 | 7 | — | 279 |
| Relating to assets sold during the period | 3 | — | — | — | — | 3 |
| Purchases, sales and settlements: | | | | | | |
| Purchases | 311 | 173 | 136 | 227 | — | 847 |
| Sales | (38) | — | (19) | (3) | — | (60) |
| Settlements [(a)] | (33) | (203) | (65) | — | — | (301) |
| Transfers into (out of) Level 3 [(b)(c)] | (30) | 16 | 27 | — | — | 13 |
| Balance as of December 31, 2014 | $1,329 | $ 904 | $744 | $272 | $ 2 | $3,251 |
| **Other Postretirement Benefits** | | | | | | |
| Balance as of January 1, 2014 | $ 4 | $ 2 | $109 | $— | $— | $ 115 |
| Actual return on plan assets: | | | | | | |
| Relating to assets still held at the reporting date | 1 | — | 13 | — | — | 14 |
| Purchases, sales and settlements: | | | | | | |
| Purchases | 109 | 1 | 1 | — | — | 111 |
| Sales | (4) | (2) | (7) | — | — | (13) |
| Settlements [(a)] | — | (1) | — | — | — | (1) |
| Balance as of December 31, 2014 | $ 110 | $ — | $116 | $— | $— | $ 226 |

| | Hedge funds | Private equity | Real estate | Fixed income | Equities | 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 [(c)] | (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 |
| Purchases, sales and settlements: | | | | | | |
| Purchases | — | 1 | 3 | — | — | 4 |
| Sales | (1) | — | — | — | — | (1) |
| Settlements [(a)] | (4) | — | — | — | — | (4) |
| Transfers into (out of) Level 3 [(c)] | (4) | — | — | — | — | (4) |
| Balance as of December 31, 2013 | $ 4 | $ 2 | $109 | $— | $— | $ 115 |

**Combined Notes to Consolidated Financial Statements—(Continued)**
**(Dollars in millions, except per share data unless otherwise noted)**

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(a) Represents cash settlements only.
(b) In connection with the Employee Matters Agreement between EDF and Exelon, Exelon assumed the pension plan assets of Nine Mile Point Nuclear Station, LLC and Constellation Energy Nuclear Group, LLC resulting in transfers into Level 3 of $56 million.
(c) As of January 1, 2014 and January 1, 2013, 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, 2014 and 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 $43 million and $627 million in 2014 and 2013 respectively.

There were no transfers between Level 1 and Level 2 during the twelve months ended December 31, 2014 for the pension and other postretirement benefit plan assets.

*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.

*Equities.* Equities consist of individually held equity securities, equity mutual funds and equity commingled funds in domestic and foreign markets. 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 Exelon is able to independently corroborate. Equity securities held individually, including rights and warrants, 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 the plans' 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 NAV 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 remaining fixed income securities, including certain other fixed income investments, 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

Other fixed income investments primarily consist of fixed income commingled funds, mutual funds, and short-term investment funds, which 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 NAV per fund share, derived from the quoted prices in active markets of the underlying securities. These funds have been categorized as Level 2. Certain fixed income commingled funds are valued using the NAV per fund share, which is based on the valuation of the underlying investments and include significant unobservable inputs. These funds have been categorized as Level 3.

**Combined Notes to Consolidated Financial Statements—(Continued)**
**(Dollars in millions, except per share data unless otherwise noted)**

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.

*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.

*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 NAV 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.

As of December 31, 2014, Exelon has outstanding commitments to invest in private equity and real estate investments of approximately $825 million. These commitments will be funded by Exelon's existing pension and other postretirement benefit trusts.

### Defined Contribution Savings Plan

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 and after-tax income in accordance with specified guidelines. All Registrants match a percentage of the employee contributions up to certain limits. The following table presents Exelon's matching contributions to the savings plan for the years ended December 31, 2014, 2013 and 2012:

| For the Year Ended December 31, | |
|---|---|
| 2014 | $103 |
| 2013 | 85 |
| 2012 | 67 |

## 17. Severance

Exelon has an ongoing severance plan under which, in general, the longer an employee worked prior to termination the greater the amount of severance benefits. Exelon records 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"), Exelon measures the obligation and records 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.

**Combined Notes to Consolidated Financial Statements—(Continued)**
**(Dollars in millions, except per share data unless otherwise noted)**

### *CENG Integration-Related Severance*

In connection with the Master Agreement, Generation and CENG recorded a severance accrual in the fourth quarter of 2013 for the anticipated employee position reductions as a result of the integration of $2 million and $16 million, respectively. The majority of these positions are corporate and support positions at CENG. On April 1, 2014, the date the NOSA was executed, Generation consolidated the $19 million CENG severance liability pursuant to the Master Agreement. For the years ended December 31, 2014 and 2013, respectively, Exelon and Generation recorded severance benefit costs associated with the employee reductions of $3 million and $2 million within Operating and maintenance expense in their Consolidated Statements of Operations and Comprehensive Income. The estimated amount of severance payments associated with this plan is expected to be approximately $24 million. As of December 31, 2014, management recorded its best estimate of severance benefits, which could be adjusted through the completion of the integration process if additional employee position reductions are identified or if employees resign prior to their agreed upon service termination date. Estimated costs to be incurred after December 31, 2014 are not material.

Amounts included in the table below represent the severance liability recorded by Exelon related to the CENG integration:

| Year Ended December 31, 2014<br>Severance Liability | |
|---|---|
| Balance at December 31, 2013 | $ 2 |
| Integration of CENG [(a)] | 19 |
| Severance charges | 3 |
| Payments | (11) |
| Balance at December 31, 2014 | $ 13 |

(a) Includes the fair value of the CENG integration-related obligation as of April 1, 2014, the date of consolidation. Note this includes an additional $3 million of severance charges incurred in the first quarter of 2014 by CENG. See Note 5—Investment in Constellation Energy Nuclear Group, LLC for additional information.

Cash payments under the severance plan began in 2014. Substantially all cash payments under the plan are expected to be made by the end of 2015.

### *Constellation 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.

The amount of severance expense associated with the post-merger integration recognized for the twelve months ended December 31, 2014 and 2013 is not material. Estimated costs to be incurred after December 31, 2014 are not immaterial.

For the year ended December 31, 2012, Exelon recorded the following severance benefit costs associated with identified job reductions within Operating and maintenance expense in their Consolidated Statements of Operations and Comprehensive Income, except for those costs that were capitalized as regulatory assets related to ComEd and BGE:

| Year Ended December 31, 2012<br>Severance Benefits [(a)] | |
|---|---|
| Severance charges | $124 |
| Stock compensation | 7 |
| Other charges | 7 |
| Total severance benefits | $138 |

(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.

**Combined Notes to Consolidated Financial Statements—(Continued)**
**(Dollars in millions, except per share data unless otherwise noted)**

Amounts included in the table below represent the severance liability recorded by Exelon:

| Severance liability | Exelon |
|---|---|
| Balance at December 31, 2012 | $111 |
| Severance charges [(a)] | 5 |
| Stock compensation | 1 |
| Payments | (64) |
| Balance at December 31, 2013 | $ 53 |
| Payments | (41) |
| Balance at December 31, 2014 | $ 12 |

(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, 2014 and December 31, 2013.

Substantially all cash payments under the plan are expected to be made by the end of 2016.

***Ongoing Severance Plans***

The Registrants provide severance, 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 or with the integration of CENG. These benefits are accrued for when the benefits are considered probable and can be reasonably estimated.

For the years ended December 31, 2014, 2013, and 2012, Exelon recorded severance costs of $7 million, $18 million, and $19 million, respectively, associated with these ongoing severance benefits within Operating and maintenance expense in their Consolidated Statements of Operations and Comprehensive Income:

The severance liability balances associated with these ongoing severance benefits as of December 31, 2014 and 2013 are not material.

### 18. Preferred and Preference Securities

At December 31, 2014 and 2013, 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, 2014 and 2013, 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.

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 was 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.

At December 31, 2014 and 2013, 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

**Combined Notes to Consolidated Financial Statements—(Continued)**
**(Dollars in millions, except per share data unless otherwise noted)**

- 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.

| | | December 31, | | | |
|---|---|---|---|---|---|
| | | 2014 | 2013 | 2014 | 2013 |
| | Redemption Price [(a)] | Shares Outstanding | | 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 | 100.00 | 400,000 | 400,000 | 40 | 40 |
| 6.99%, 1995 Series | 100.35 | 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, 2014 and 2013:

| | | | December 31, | |
|---|---|---|---|---|
| | | | 2014 | 2013 |
| | Par Value | Shares Authorized | Shares Outstanding | |
| **Common Stock** | | | | |
| Exelon | no par value | 2,000,000,000 | 859,833,343 | 857,290,484 |
| ComEd | $12.50 | 250,000,000 | 127,016,947 | 127,016,896 |
| 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 73,533 and 73,709 warrants outstanding to purchase ComEd common stock at December 31, 2014 and 2013, 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, 2014 and 2013, 24,511 and 24,570 shares of common stock, respectively, were reserved for the conversion of warrants.

#### Equity Securities Offering

In June 2014, Exelon marketed an equity offering of 57.5 million shares of its common stock at a public offering price of $35 per share. In connection with such offering, Exelon entered into forward sale agreements requiring Exelon to, at its election, prior to October 29, 2015; i) physically settle the transaction through the issuance of 57.5 million shares of its common stock in exchange for net proceeds at the forward price specified in the agreements of between approximately $1.8 billion and $1.9 billion, after consideration of underwriters discount of approximately $60 million and subject to certain adjustments as provided in the forward sales agreement, or ii) net settle the transaction either through the payment of cash or shares of its common stock based on the then current market value of the shares minus the value of the shares at the forward price, net of the underwriters discount and the daily accretion rate. No amounts have or will be recorded in Exelon's consolidated financial statements with respect to the equity offering until settlement of the forward sale agreements occurs. If Exelon elected to net share settle the contract as of December 31, 2014, Exelon would have been required to issue 4 million shares. If Exelon elects to cash settle the contract, the transaction costs will be recorded as a charge to earnings in the period in which it becomes probable that Exelon will cash settle. Otherwise, all transaction costs will be reflected as a reduction to the value of the common stock issued in Exelon's Consolidated Balance Sheet. The net proceeds received upon settlement are expected to be used to finance a portion of the acquisition of PHI and for general corporate purposes. Until settlement, earnings per share dilution resulting from the forward sales agreement, if any, will be determined under the treasury stock method.

**Combined Notes to Consolidated Financial Statements—(Continued)**
**(Dollars in millions, except per share data unless otherwise noted)**

Concurrent with the forward equity transaction, Exelon also issued $1.15 billion of junior subordinated notes in the form of 23 million equity units. See Note 13—Debt and Credit Agreements for further information on the equity units.

### 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, 2014. During 2014, 2013 and 2012, Exelon had no common stock repurchases.

### 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, 2014, there were approximately 16 million shares authorized for issuance under the LTIP. For the years ended December 31, 2014, 2013 and 2012, 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 67% performance shares and 33% restricted stock units. 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 vested one-third after one year, with the remaining balance vesting over a two-year performance period. These one-time 2013 performance share transition awards 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 Exelon stock ownership requirements are satisfied. In addition to this change, in 2013 ComEd and in 2014 PECO and BGE transitioned from Exelon stock-based awards to cash award programs with payouts based on the performance of each respective utility. The following tables do not include expense related to these plans as they are not considered stock-based compensation plans under the applicable accounting guidance.

The following table presents the stock-based compensation expense included in Exelon's Consolidated Statements of Operations and Comprehensive Income for the years ended December 31, 2014, 2013 and 2012:

| Components of Stock-Based Compensation Expense | Year Ended December 31, 2014 | 2013 | 2012 |
|---|---|---|---|
| Performance share awards | $ 59 | $ 48 | $ 46 |
| Restricted stock units | 61 | 61 | 50 |
| Stock options | 2 | 3 | 15 |
| Other stock-based awards | 5 | 6 | 4 |
| Total stock-based compensation expense included in operating and maintenance expense | 127 | 118 | 115 |
| Income tax benefit | (47) | (44) | (44) |
| Total after-tax stock-based compensation expense | $ 80 | $ 74 | $ 71 |

There were no significant stock-based compensation costs capitalized during the years ended December 31, 2014, 2013 and 2012.

**Combined Notes to Consolidated Financial Statements—(Continued)**
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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, 2014, 2013 and 2012:

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2014 | 2013 | 2012 |
| Realized tax benefit when exercised/distributed: | | | |
| Stock options | $— | $— | $ 3 |
| Restricted stock units | 17 | 11 | 11 |
| Performance share awards | 11 | 11 | 7 |
| Stock deferral plan | — | 1 | — |
| Excess tax benefits included in other financing activities of Exelon's Consolidated Statements of Cash Flows: | | | |
| Stock options | $— | $— | $ 2 |

*Stock Options*

Non-qualified stock options to purchase shares of Exelon's common stock were granted under the LTIP through 2012. Due to changes in the LTIP, there were no stock options granted in 2013 or 2014. For all stock options granted through 2012, 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.

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.

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 year ended 2012:

| | Year ended December 31, 2012 |
|---|---|
| Dividend yield | 5.28% |
| Expected volatility | 23.20% |
| Risk-free interest rate | 1.30% |
| Expected life (years) | 6.25 |
| Weighted average grant date fair value (per share) | 4.18 |

The assumptions above relate to Exelon stock options granted in 2012 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.

**Combined Notes to Consolidated Financial Statements—(Continued)**
**(Dollars in millions, except per share data unless otherwise noted)**

The following table presents information with respect to stock option activity for the year ended December 31, 2014:

| | Shares | Weighted Average Exercise Price (per share) | Weighted Average Remaining Contractual Life (years) | Aggregate Intrinsic Value |
|---|---|---|---|---|
| Balance of shares outstanding at December 31, 2013 | 21,035,445 | $46.07 | | |
| Options exercised | (291,805) | 25.27 | | |
| Options forfeited | (8,886) | 55.78 | | |
| Options expired | (1,903,787) | 41.47 | | |
| Balance of shares outstanding at December 31, 2014 | 18,830,967 | $46.85 | 4.11 | $29 |
| Exercisable at December 31, 2014 [(a)] | 18,398,932 | $47.01 | 4.04 | $29 |

(a) Includes stock options issued to retirement eligible employees.

The following table summarizes additional information regarding stock options exercised for the years ended December 31, 2014, 2013 and 2012:

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2014 | 2013 | 2012 |
| Intrinsic value [(a)] | $3 | $ 4 | $19 |
| Cash received for exercise price | 7 | 19 | 47 |

(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, 2014:

| | Shares | Weighted Average Exercise Price (per share) |
|---|---|---|
| Nonvested at December 31, 2013 [(a)] | 847,118 | $40.22 |
| Vested | (406,197) | 40.21 |
| Forfeited | (8,886) | 55.78 |
| Nonvested at December 31, 2014 [(a)] | 432,035 | $39.91 |

(a) Excludes 746,140 and 1,348,913 of stock options issued to retirement-eligible employees as of December 31, 2014 and December 31, 2013, respectively, as they are fully vested.

At December 31, 2014, $1 million of total unrecognized compensation costs related to nonvested stock options are expected to be recognized over the remaining weighted-average period of 1.0 year.

*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.

**Combined Notes to Consolidated Financial Statements—(Continued)**
**(Dollars in millions, except per share data unless otherwise noted)**

The following table summarizes Exelon's nonvested restricted stock unit activity for the year ended December 31, 2014:

| | Shares | Weighted Average Grant Date Fair Value (per share) |
|---|---|---|
| Nonvested at December 31, 2013 [(a)] | 3,386,697 | $34.10 |
| Granted | 2,252,574 | 28.71 |
| Vested | (1,216,016) | 35.36 |
| Forfeited | (86,094) | 31.99 |
| Undistributed vested awards [(b)] | (578,943) | 29.17 |
| Nonvested at December 31, 2014 [(a)] | 3,758,218 | $31.27 |

(a) Excludes 975,116 and 931,628 of restricted stock units issued to retirement-eligible employees as of December 31, 2014 and December 31, 2013, respectively, as they are fully vested.
(b) Represents restricted stock units that vested but were not distributed to retirement-eligible employees during 2014.

The weighted average grant date fair value (per share) of restricted stock units granted for the years ended December 31, 2014, 2013 and 2012 was $28.71, $31.06 and $39.94, respectively. At December 31, 2014 and 2013, Exelon had obligations related to outstanding restricted stock units not yet settled of $85 million and $77 million, respectively, which are included in common stock in Exelon's Consolidated Balance Sheets. For the years ended December 31, 2014, 2013 and 2012, Exelon settled restricted stock units with fair value totaling $43 million, $28 million and $25 million, respectively. At December 31, 2014, $59 million of total unrecognized compensation costs related to nonvested restricted stock units are expected to be recognized over the remaining weighted-average period of 2.1 years.

*Performance Share Awards*

Performance share awards are granted under the LTIP. The 2014 and 2013 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 common stock portion of the performance share and one-time 2013 performance share transition awards is considered an equity award and is 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.

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, 2014:

| | Shares | Weighted Average Grant Date Fair Value (per share) |
|---|---|---|
| Nonvested at December 31, 2013 [(a)] | 2,014,190 | $32.74 |
| Granted | 1,712,085 | 28.75 |
| Change in performance | 98,227 | 31.85 |
| Vested | (497,714) | 35.05 |
| Forfeited | (29,476) | 30.16 |
| Undistributed vested awards [(b)] | (601,215) | 28.96 |
| Nonvested at December 31, 2014 [(a)] | 2,696,097 | $30.62 |

**Combined Notes to Consolidated Financial Statements—(Continued)**
**(Dollars in millions, except per share data unless otherwise noted)**

(a) Excludes 1,535,791 and 1,411,824 of performance share awards issued to retirement-eligible employees as of December 31, 2014 and December 31, 2013, respectively, as they are fully vested.
(b) Represents performance share awards that vested but were not distributed to retirement-eligible employees during 2014.

The weighted average grant date fair value (per share) of performance share awards granted during the years ended December 31, 2014, 2013 and 2012 was $28.75, $31.55, and $39.71, respectively. During the years ended December 31, 2014, 2013 and 2012, Exelon settled performance shares with a fair value totaling $27 million, $26 million and $23 million, respectively, of which $13 million, $12 million and $3 million was paid in cash, respectively. As of December 31, 2014, $54 million of total unrecognized compensation costs related to nonvested performance shares are expected to be recognized over the remaining weighted-average period of 1.6 years.

The following table presents the balance sheet classification of obligations related to outstanding performance share awards not yet settled:

| | December 31, | |
|---|---|---|
| | 2014 | 2013 |
| Current liabilities [(a)] | $28 | $13 |
| Deferred credits and other liabilities [(b)] | 36 | 24 |
| Common stock | 33 | 32 |
| Total | $97 | $69 |

(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

### *Earnings per Share*

Diluted earnings per share is calculated by dividing Net income attributable to common shareholders 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 the 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, | | |
|---|---|---|---|
| | 2014 | 2013 | 2012 |
| Net income attributable to common shareholders | $1,623 | $1,719 | $1,160 |
| Weighted average common shares outstanding—basic | 860 | 856 | 816 |
| Assumed exercise and/or distributions of stock-based awards | 4 | 4 | 3 |
| Weighted average common shares outstanding—diluted | 864 | 860 | 819 |

The number of stock options not included in the calculation of diluted common shares outstanding due to their antidilutive effect was approximately 17 million in 2014, 20 million in 2013, and 14 million in 2012. The number of equity units related to the PHI merger not included in the calculation of diluted common shares outstanding due to their antidilutive effect was less than 1 million for the year ended December 31, 2014 since issuance. Additionally, there were no forward units related to the PHI merger not included in the calculation of diluted common shares outstanding due to their antidilutive effect for the year ended December 31, 2014 since issuance. Refer to Note 19—Common Stock for further information regarding the equity units and equity forward units.

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, 2014. In 2008, Exelon management decided to defer indefinitely any share repurchases.

**Combined Notes to Consolidated Financial Statements—(Continued)**
**(Dollars in millions, except per share data unless otherwise noted)**

## 21. Changes in Accumulated Other Comprehensive Income

The following tables present changes in accumulated other comprehensive income (loss) (AOCI) by component for the years ended December 31, 2014 and 2013:

| For the Year Ended December 31, 2014 | 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 | $ 120 | $ 2 | $(2,260) | $(10) | $ 108 | $(2,040) |
| OCI before reclassifications | (31) | (1) | (498) | (9) | 11 | (528) |
| Amounts reclassified from AOCI [b] | (117) | 2 | 118 | — | (119) | (116) |
| Net current-period OCI | (148) | 1 | (380) | (9) | (108) | (644) |
| Ending balance | $ (28) | $ 3 | $(2,640) | $(19) | $ — | $(2,684) |

| 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) |

(a) All amounts are net of tax. Amounts in parenthesis represent a decrease in accumulated other comprehensive income.
(b) See next tables for details about these reclassifications.

**Combined Notes to Consolidated Financial Statements—(Continued)**
**(Dollars in millions, except per share data unless otherwise noted)**

The following tables present amounts reclassified out of AOCI to Net income during the years ended December 31, 2014 and 2013:

**For the Year Ended December 31, 2014**

| Details about AOCI components | Items reclassified out of AOCI [(a)] | Affected line item in the Statements of Operations and Comprehensive Income |
|---|---|---|
| Gains and (losses) on cash flow hedges | | |
| Energy related hedges | $ 195 | Operating revenues |
| | 195 | Total before tax |
| | (78) | Tax expense |
| | $ 117 | Net of tax |
| Gains and (losses) on available for sale securities | | |
| Other available securities for sale | $ (2) | Other Income and Deductions |
| | $ (2) | Net of tax |
| Amortization of pension and other postretirement benefit plan items | | |
| Prior service costs [(b)] | $ 46 | |
| Actuarial losses [(b)] | (239) | |
| | (193) | Total before tax |
| | 75 | Tax benefit |
| | $(118) | Net of tax |
| Equity investments | | |
| Sale of equity method investment | $ 5 | |
| Reversal of CENG equity method AOCI | 193 | Equity in losses of unconsolidated affiliates |
| | 198 | Total before tax |
| | (79) | Tax expense |
| | $ 119 | Net of tax |
| Total Reclassifications | $ 116 | Net of tax |

**Combined Notes to Consolidated Financial Statements—(Continued)**
**(Dollars in millions, except per share data unless otherwise noted)**

**For the Year Ended December 31, 2013**

| Details about AOCI components | Items reclassified out of AOCI [(a)] | Affected line item in the Statements of Operations and Comprehensive Income |
|---|---|---|
| Gains and (losses) on cash flow hedges | | |
| Energy related hedges | $ 464 | Operating revenues |
| Other cash flow hedges | (3) | Interest expense |
| | 461 | Total before tax |
| | (184) | Tax expense |
| | $ 277 | Net of tax |
| Amortization of pension and other postretirement benefit plan items | | |
| Prior service costs [(b)] | $ (2) | |
| Actuarial losses [(b)] | (339) | |
| Deferred compensation unit plan [(c)] | (1) | |
| | (342) | Total before tax |
| | 134 | Tax benefit |
| | $(208) | Net of tax |
| Equity investments | | |
| Capital activity | $ (8) | Equity in losses of unconsolidated affiliates |
| | (8) | Total before tax |
| | 3 | Tax benefit |
| | $ (5) | Net of tax |
| Total Reclassifications | $ 64 | 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—Retirement Benefits for additional details).
(c) Amortization of the deferred compensation unit plan is allocated to capital and operating and maintenance expense.

The following table presents income tax expense (benefit) allocated to each component of other comprehensive income (loss) during the years ended December 31, 2014 and 2013:

| | For the Years Ended December 31, | | |
|---|---|---|---|
| | 2014 | 2013 | 2012 |
| Pension and non-pension postretirement benefit plans: | | | |
| Prior service benefit reclassified to periodic benefit cost | $ 19 | $ — | $ (1) |
| Actuarial loss reclassified to periodic cost | (93) | (133) | (110) |
| Transition obligation reclassified to periodic cost | — | — | (2) |
| Pension and non-pension postretirement benefit plans valuation adjustment | 317 | (430) | 237 |
| Change in unrealized loss on cash flow hedges | 96 | 166 | 68 |
| Change in marketable securities | — | — | 1 |
| Change in unrealized income on equity investments | 73 | (71) | (1) |
| Total | $412 | $(468) | $ 192 |

### 22. Commitments and Contingencies

#### 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 mitigated 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, 2014, 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 $2.7 billion, including CENG's related liability.

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.

As part of the execution of NOSA on April 1, 2014, Generation executed an Indemnity Agreement pursuant to which Generation agreed to 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 guarantees Generation's obligations under this indemnity. See Note 5—Investment in Constellation Energy Nuclear Group, LLC for additional information on Generation's operations relating to CENG.

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 2014 and 2013, of which Generation's portion was $18.3 million and $18.5 million respectively. No distributions were declared in 2012. The distributions were recorded as a reduction to Operating and maintenance expense within Exelon and Generation's Consolidated Statements of Operations and Comprehensive Income. 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, 2014, the current maximum aggregate annual retrospective premium obligation for Generation is approximately $319 million. 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.

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. 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

**Combined Notes to Consolidated Financial Statements—(Continued)**
**(Dollars in millions, except per share data unless otherwise noted)**

of insurance proceeds to Generation and the amount of such proceeds that would be available. 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.

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 historically had paid the DOE one mill ($0.001) per kWh of net nuclear generation for the cost of SNF disposal. On November 19, 2013, the D.C. Circuit Court 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 May 9, 2014, the DOE notified Generation that the SNF disposal fee remained in effect through May 15, 2014, after which time the fee was set to zero. For the year ended December 31, 2014, and for the year ended December 31, 2013, Generation incurred expense of $49 million and $136 million, respectively, in SNF disposal fees, recorded in Purchased power and fuel expense within Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income, including Exelon's share of Salem and net of co-owner reimbursements (not including such fees incurred by CENG). Until such time as a new fee structure is in effect, Exelon and Generation will not accrue any further costs related to SNF disposal fees. 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 has been, and is expected to be, delayed significantly.

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, Quad Cities, Ginna, Nine Mile Point, and Calvert Cliffs 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. Settlement agreements pertaining to Calvert Cliffs and Ginna were executed during 2011, and Nine Mile Point during 2012, (the "DOE Settlement Agreements"), as amended in 2014 for Calvert Cliffs and Nine Mile Point, under which the government has agreed to reimburse the costs associated with SNF storage expended or to be expended through 2016 as a result of the DOE delays. The DOE Settlement Agreement is expected to be amended for Ginna in a similar manner as needed. Generation, including CENG, 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.

**Combined Notes to Consolidated Financial Statements—(Continued)**
**(Dollars in millions, except per share data unless otherwise noted)**

Under the settlement agreement, Generation has received cumulative cash reimbursements for costs incurred as follows:

| | Total | Net [(a)] |
|---|---|---|
| Cumulative cash reimbursements [(b)] | $836 | $702 |

(a) Total after considering amounts due to co-owners of certain nuclear stations and to the former owner of Oyster Creek.
(b) Includes $33 million and $30 million, respectively, for amounts received since April 1, 2014, for costs incurred under the CENG DOE Settlement Agreements prior to the consolidation of CENG.

As of December 31, 2014, and 2013, the amount of SNF storage costs for which reimbursement has been or will be requested from the DOE under the DOE settlement agreements is as follows:

| | December 31, 2014 | December 31, 2013 |
|---|---|---|
| DOE receivable—current [(a)] | $82 | $ 71 |
| DOE receivable—noncurrent [(b)] | 7 | — |
| Amounts owed to co-owners [(a)(c)] | (5) | (18) |

(a) Recorded in Accounts receivable, other.
(b) Recorded in Deferred debits and other assets, other
(c) Non-CENG amounts owed to co-owners are recorded in Accounts receivable, other. CENG amounts owed to co-owners are recorded in Accounts payable. Represents amounts owed to the co-owners of Peach Bottom, Quad Cities, and Nine Mile Point Unit 2 generating facilities.

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, 2014, 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, 2014, was 0.020%. 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 Nine Mile Point, Ginna, Oyster Creek and TMI units remain with the former owners. The Clinton and Calvert Cliffs units have no outstanding obligation. See Note 11—Fair Value of Financial Assets and Liabilities for additional information.

### 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.

**Combined Notes to Consolidated Financial Statements—(Continued)**
**(Dollars in millions, except per share data unless otherwise noted)**

At December 31, 2014, 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) | Total |
|---|---|---|---|---|
| 2015 | $ 418 | $152 | $ 20 | $ 590 |
| 2016 | 283 | 228 | 15 | 526 |
| 2017 | 222 | 121 | 15 | 358 |
| 2018 | 112 | 29 | 16 | 157 |
| 2019 | 117 | 5 | 16 | 138 |
| Thereafter | 279 | 1 | 35 | 315 |
| Total | $1,431 | $536 | $117 | $2,084 |

(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, 2014, net of fixed capacity payments expected to be received ("capacity offsets") by Generation under contracts to resell such acquired capacity to third parties under long-term capacity sale contracts. As of December 31, 2014, capacity offsets were $132 million, $133 million, $136 million, $137 million, $138 million, and $591 million for years 2015, 2016, 2017, 2018, 2019, and thereafter, respectively. 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.

PECO has entered into contracts through a competitive procurement process in order to meet a portion of its default service customers' electric supply requirements through 2016. See Note 3—Regulatory Matters for further information regarding the DSP Programs.

ComEd is subject to requirements established by the Illinois 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. 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, 2014 are as follows:

| | | Expiration within | | | | | |
|---|---|---|---|---|---|---|---|
| | Total | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 and beyond |
| ComEd | | | | | | | |
| Electric supply procurement (a) | $ 620 | $329 | $151 | $140 | $— | $— | $ — |
| Renewable energy and RECs (b) | 1,517 | 75 | 76 | 77 | 78 | 84 | 1,127 |
| PECO | | | | | | | |
| Electric supply procurement (c) | 609 | 527 | 82 | — | — | — | — |
| AECs (d) | 13 | 2 | 2 | 2 | 2 | 2 | 3 |
| BGE | | | | | | | |
| Electric supply procurement (e) | 1,315 | 779 | 448 | 88 | — | — | — |
| Curtailment services (f) | 115 | 40 | 34 | 29 | 12 | — | — |

(a) ComEd is permitted to recover its electric supply procurement costs from retail customers with no mark-up. As of December 31, 2014, ComEd has completed the ICC-approved procurement process for a portion of its energy requirements through the periods ending May 31, 2015, 2016 and 2017.
(b) Primarily related to ComEd 20-year contracts for renewable energy and RECs that began in June 2012. ComEd is permitted to recover its renewable energy and REC costs from retail customers with no mark-up. The commitments represent the maximum settlements with suppliers for renewable energy and RECs under the existing contract terms.

**Combined Notes to Consolidated Financial Statements—(Continued)**
**(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 2015 and 2016. 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 2015 through 2017. 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. Beginning with the second quarter of 2014, 100% of CENG's nuclear fuel commitments are disclosed within the Generation line below, since CENG is now fully consolidated by Generation. PECO and BGE have commitments to purchase natural gas related to transportation, storage capacity and services to serve customers in their gas distribution service territory. As of December 31, 2014, these commitments were as follows:

| | | Expiration within | | | | | |
|---|---|---|---|---|---|---|---|
| | Total | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 and beyond |
| Generation | $8,981 | $1,404 | $1,119 | $1,124 | $1,001 | $888 | $3,445 |
| PECO | 428 | 146 | 103 | 60 | 34 | 14 | 71 |
| BGE | 611 | 111 | 82 | 67 | 57 | 54 | 240 |

### Other Purchase Obligations

The Registrants' other purchase obligations as of December 31, 2014, which primarily represent commitments for services, materials and information technology, are as follows:

| | | Expiration within | | | | | |
|---|---|---|---|---|---|---|---|
| | Total | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 and beyond |
| Exelon | $894 | $336 | $258 | $150 | $ 36 | $ 30 | $ 84 |
| Generation (a)(b) | 396 | 163 | 67 | 42 | 30 | 24 | 70 |
| ComEd (c) | 148 | 63 | 77 | 1 | 1 | 1 | 5 |
| PECO (c) | 7 | 3 | 4 | — | — | — | — |
| BGE (c) | 343 | 107 | 110 | 107 | 5 | 5 | 9 |

(a) Purchase obligations do not include commitments related to construction contracts. See Construction Commitments section below for additional information.
(b) Purchase obligations include commitments related to assets-held-for-sale. See Note 4—Mergers, Acquisitions, and Dispositions for additional information.
(c) Purchase obligations include commitments related to smart meter installation. See Note 3—Regulatory Matters for additional information.

### Commercial Commitments

Exelon's commercial commitments as of December 31, 2014, representing commitments potentially triggered by future events, were as follows:

| | | Expiration within | | | | | |
|---|---|---|---|---|---|---|---|
| | Total | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 and beyond |
| Letters of credit (non-debt) (a) | $1,233 | $1,151 | $ 77 | $ 5 | $— | $— | $ — |
| Surety bonds(b) | 596 | 545 | 10 | 4 | 1 | 2 | 34 |
| Performance guarantees (c) | 1,239 | 472 | 20 | 20 | 20 | 20 | 687 |
| Energy marketing contract guarantees (d) | 3,220 | 3,220 | — | — | — | — | — |
| Lease guarantees(e) | 40 | — | — | — | — | — | 40 |
| Nuclear insurance premiums (f) | 3,014 | — | — | — | — | — | 3,014 |
| Underwriters discount (g) | 60 | 60 | — | — | — | — | — |
| Total commercial commitments | $9,402 | $5,448 | $107 | $ 29 | $ 21 | $ 22 | $3,775 |

**Combined Notes to Consolidated Financial Statements—(Continued)**
**(Dollars in millions, except per share data unless otherwise noted)**

(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. Additionally includes $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 $3.2 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 $0.6 billion at December 31, 2014, which represents the total amount Exelon could be required to fund based on December 31, 2014 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.
(g) Represents the underwriters discount for Exelon's forward equity transaction. See Note 19—Common Stock for further details of the equity securities offering.

### Construction Commitments

Generation's ongoing investments in renewables development and new natural gas construction illustrates Generation's growth strategy to provide for diversification opportunities while leveraging its expertise and strengths.

Generation completed the construction of the Antelope Valley solar PV facility in Los Angeles County, California, which became fully operational in the first half of 2014. Generation has no further remaining construction commitments for the project.

On July 3, 2013, Generation executed a turbine supply agreement to expand its Beebe wind project in Michigan. The remaining commitment is approximately $2 million under the contract and achievement of commercial operations was attained 2014.

On July 26, 2013, Generation executed an engineering procurement and construction contract to expand its Perryman, Maryland generation site with at least 120MW of new natural gas-fired generation. The remaining commitment is approximately $39 million under the contract and achievement of commercial operation is expected in 2015. This project will satisfy a portion of Exelon's commitment to Maryland. See Note 4—Mergers, Acquisitions, and Dispositions for additional information on commitments to develop or assist in development of new generation in Maryland resulting from the Constellation merger.

On December 27, 2013, Generated executed a turbine supply agreement for construction of the 40MW Fourmile Wind project in western Maryland. The remaining commitment is approximately $2 million under the contract and achievement of commercial operations was attained in 2014. This project will satisfy a portion of Exelon's 125 MW Tier I land-based renewables commitment made to Maryland. See Note 4—Mergers, Acquisitions, and Dispositions for additional information on commitments to develop or assist in development of new generation in Maryland resulting from the Constellation merger.

During the third and fourth quarter of 2014, Generation executed contracts associated with the construction of new combined-cycle gas turbine units in Texas. The remaining commitment is approximately $1.0 billion under these contracts and achievement of commercial operations is expected in 2017.

During the fourth quarter of 2014 Generation executed contracts associated with the construction of the 30 MW Fair Wind project in western Maryland. The remaining commitment is approximately $19 million under these contracts and achievement of commercial operations is expected in 2015. This project will satisfy a portion of Exelon's 125 MW Tier I land-based renewables commitment made to Maryland. See Note 4—Mergers, Acquisitions, and Dispositions for additional information on commitments to develop or assist in development of new generation in Maryland resulting from the Constellation merger.

During the fourth quarter of 2014 Generation executed contracts associated with the construction of the 78 MW Sendero Wind project in southern Texas. The remaining commitment is approximately $56 million under these contracts and achievement of commercial operations is expected in 2015.

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.

**Combined Notes to Consolidated Financial Statements—(Continued)**
**(Dollars in millions, except per share data unless otherwise noted)**

### *Equity Investment Commitments*

As part of Generation's recent investments in technology development, Generation has entered into equity purchase agreements which include commitments to purchase additional equity through incremental payments. The additional equity is provided by the agreements to fund the anticipated needs of the planned operations of the associated companies. The commitment includes approximately $20 million of in-kind services. As of December 31, 2014, Generation's estimated commitment relating to its equity purchase agreements, including the in-kind services contributions, is anticipated to be as follows:

| | Total |
|---|---|
| 2015 | $ 98 |
| 2016 | 38 |
| 2017 | 20 |
| 2018 | 11 |
| Total | $167 |

### 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, 2014 were:

| | Exelon |
|---|---|
| 2015 | $ 99 |
| 2016 | 102 |
| 2017 | 102 |
| 2018 | 86 |
| 2019 | 70 |
| Remaining years | 699 |
| Total minimum future lease payments | $1,158[(a)] |

(a) Excludes Generation's PPAs and tolling arrangements that are accounted for as contingent operating lease payments, since these expected cash outflows are already disclosed in the Net Capacity Purchases table under the Energy Commitment.

The following table presents Exelon's rental expense under operating leases for the years ended December 31, 2014, 2013 and 2012:

| For the Year Ended December 31, [(a)] | |
|---|---|
| 2014 | $865 |
| 2013 | 806 |
| 2012 | 930 |

(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 $755 million, $694 million and $801 million during 2014, 2013 and 2012, respectively.

For information regarding capital lease obligations, see Note 13—Debt and Credit Agreements.

### Indemnifications Related to Sale of Sithe

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. The guarantee expired January 31, 2014. Generation was not required to make payments under the guarantee, and, therefore, has no further obligation related to this guarantee.

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

**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 now or formerly owned by them and of property contaminated by hazardous substances generated by them. The Registrants own or lease a number of real estate parcels, including parcels on which their operations or the operations of others may have resulted in contamination by substances that are considered hazardous under environmental laws. In addition, the Registrants are currently involved in a number of proceedings relating to sites where hazardous substances have been deposited and may be subject to additional proceedings in the future.

ComEd, PECO and BGE have identified sites where former MGP activities have or may have resulted in actual site contamination. For almost all of these sites, there are additional PRPs that may share responsibility for the ultimate remediation of each location.

- ComEd has identified 42 sites, 17 of which the remediation has been completed and approved by the Illinois EPA or the U.S. EPA and 25 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 2019.
- PECO has identified 26 sites, 16 of which have been remediated in accordance with applicable PA DEP regulatory requirements. The remaining 10 sites 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 2021.
- 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. At this time, BGE is unable to estimate the results of this investigation.

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 recover, 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. See Note 3—Regulatory Matters for additional information regarding the associated regulatory assets.

As of December 31, 2014 and 2013, Exelon has accrued the following undiscounted amounts for environmental liabilities in other current liabilities and other deferred credits and other liabilities within its Consolidated Balance Sheets:

| | Total environmental investigation and remediation reserve | Portion of total related to MGP investigation and remediation |
|---|---|---|
| December 31, 2014 | $347 | $277 |
| December 31, 2013 | 338 | 273 |

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 activity. Management determines its best estimate of remediation costs based on probabilistic and deterministic modeling using all available information at the time of each study and the remediation standards currently required by the applicable state environmental agency. Prior to completion of any significant clean up, each site remediation plan is approved by the appropriate state environmental agency.

During the third quarter of 2014, 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 environmental liabilities and related regulatory assets by $26 million and $4 million, respectively, primarily reflecting refined assumptions regarding clean-up techniques and scopes based on additional experience and analysis as site clean-up and investigation activities progress.

**Combined Notes to Consolidated Financial Statements—(Continued)**
**(Dollars in millions, except per share data unless otherwise noted)**

BGE has established a reserve for the active sites that is not material. Given that the former gas purification site is in the early stages of investigation and the extent of contamination is not currently known, BGE is unable to estimate actual remediation costs, which may be material to BGE's results of operations, cash flows, and financial position.

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***

***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. As of December 31, 2014 and 2013, Generation's remaining groundwater contamination reserve was $13 million and $14 million. respectively.

***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.

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.

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 an agency agreement related to a coal rail car lease under which Midwest Generation had agreed to reimburse ComEd for all obligations incurred under the coal rail car lease. The rejection left Generation as the party responsible for making all remaining payments under the lease and performing all other obligations thereunder. In January 2013, Generation made the final $10 million payment due under the lease agreement which had been accrued at December 31, 2012.

On March 11, 2014, the Bankruptcy Court for the Northern District of Illinois entered its Order Confirming Debtors' Joint Chapter 11 Plan of Reorganization. On April 1, 2014 (Effective Date), NRG Energy purchased EME's portfolio of generation, including Midwest Generation and the Joint Chapter 11 Plan of Reorganization (Plan) became effective. As part of the Plan, the sale agreement, including the environmental indemnity, and the asbestos cost-sharing agreement were rejected. Creditors were provided 30 days from the Effective Date to file rejection damages claims associated with contracts rejected under the Plan.

During the second quarter of 2013, Exelon filed proofs of claim for approximately $21 million with the Bankruptcy Court for amounts owed by EME and Midwest Generation related to the coal rail car lease. 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 and a claim under the asbestos cost-sharing agreement with an unspecified amount. A settlement was approved on January 22, 2015, to resolve the claims related to the coal rail car lease for $14 million. Exelon received the funds and recorded the corresponding gain January 2015.

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

**Combined Notes to Consolidated Financial Statements—(Continued)**
**(Dollars in millions, except per share data unless otherwise noted)**

(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. 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 March 31, 2014 Form 10-Q, its last public filing prior to its deregistration, that (i) it has accrued a probable amount of approximately $9 million for estimated environmental investigation and remediation costs under CERCLA, or similar laws, for the investigation and remediation of contaminated property at two 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, 2014. 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.

Generation increased its reserve for asbestos-related bodily injury claims at December 31, 2013 by $25 million, as a result of Midwest Generation listing such agreement in the January 2014 plan supplement as an agreement to be rejected in connection with the Plan. As discussed above, the rejection became effective as part of the Plan. Subsequently, Generation increased its reserve by $15 million pursuant to the second quarter 2014 actuarial study of such claims, of which an estimated $6 million pertains to Midwest Generation's share. Midwest Generation publicly disclosed in its March 31, 2014 Form 10-Q, its last public filing prior to its deregistration, that it had $53 million recorded related to asbestos bodily injury claims under the contractual indemnity with ComEd. Exelon and Generation may be entitled to damages associated with the rejection of the agreement. These amounts are considered to be contingent gains and would not be recognized until realized.

***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. 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, and subsequently requested additional analysis sampling and modeling that will be conducted throughout 2015. In light of these additional requests, it is unknown when the U.S EPA will propose a remedy for public comment, but will likely be sometime in 2016 at the earliest. 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. The current estimated cost of the landfill cover remediation for the site is approximately $50 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.

On April 11, 2014, a class action complaint was filed in the U.S. District Court for the Eastern District of Missouri against Cotter and six additional defendants. The complaint alleges that individuals living in the North St. Louis area within a three-mile radius of the West Lake Landfill suffered damage to property or loss of use of property due to the defendants' negligent handling of radioactive materials. On August 22, 2014, the plaintiffs voluntarily dismissed the case without prejudice.

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

**Combined Notes to Consolidated Financial Statements—(Continued)**
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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 2015 so that settlement discussions could proceed. Based on Generation's preliminary review, it appears probable that Generation 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 Exelon 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, Generation, and ComEd 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 Generation's preliminary review, it appears probable that Generation has liability and has established an appropriate accrual for its share of the estimated clean-up costs. A wholly owned subsidiary of Generation has agreed to indemnify BGE 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 $10 million, which has been fully reserved as of December 31, 2014.

***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.

**Combined Notes to Consolidated Financial Statements—(Continued)**
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***Coal Combustion Residuals.*** On December 19, 2014, the U.S. EPA issued the first federal regulation for the disposal of coal combustion residuals (CCR) from power plants, including the classification of CCR as non-hazardous waste under RCRA. The EPA ruling is effective 180 days after publication in the Federal Register, which is anticipated in early 2015. Under the regulation, CCR will continue to be regulated by most states subject to coordination with the federal regulations. Generation has previously recorded reserves consistent with state regulation for its owned coal ash sites, and as such, the regulation is not expected to impact Exelon's and Generation's financial results. Generation is evaluating what, if any, incremental costs will be incurred for coal ash disposal sites formerly owned by Generation that have not yet been closed by their current owners. At this time, however, Generation does not have sufficient information to reasonably assess the potential likelihood or magnitude of any remediation requirements that may be asserted for these former sites under the new federal regulations. For these reasons, Generation is unable to predict whether and to what extent they may ultimately be held responsible for remediation and other costs relating to formerly owned coal ash disposal sites under the new regulations, and as a result no new liability has been recorded as of December 31, 2014.

**Litigation and Regulatory Matters**

***Asbestos Personal Injury Claims***

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, 2014 and 2013, Generation had reserved approximately $100 million and $90 million, respectively, in total for asbestos-related bodily injury claims. As of December 31, 2014, approximately $22 million of this amount related to 255 open claims presented to Generation, while the remaining $78 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. During the second quarter of 2014, Generation increased its reserve by approximately $15 million, primarily due to increased actual and projected number and severity of claims.

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, 2014. 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.

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***

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 Constellation 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 within its Statement of Operations and Comprehensive Income with the remaining $50 million recorded as a Constellation pre-acquisition contingency within its Consolidated Balance Sheets. See Note 4—Mergers, Acquisitions, and Dispositions for additional information on the Constellation merger.

***Continuous Power Interruption***

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. 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. On July 31, 2014, the Illinois Appellate Court reaffirmed the ICC's decision in the appeal of the Summer 2011 Storm Docket and dismissed the appeal of the February 2011 Blizzard Docket. The Illinois Appellate Court's opinion has no accounting impact as ComEd previously established a liability in connection with the June 5, 2013 ICC ruling discussed below. ComEd has asked the Illinois Supreme Court to hear the matter. There is no set time in which the Court must decide whether it will take the case.

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***

On November 19, 2013, a class action complaint was filed in the Northern District of Illinois on behalf of a single individual and a presumptive class that would include all customers that ComEd enrolled in its 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. ComEd intends to contest the allegations of this suit. In February 2014, ComEd filed a motion to dismiss this class action complaint, which was denied in June 2014. As of December 31, 2014, ComEd has a reserve, which is not material, representing its best estimate of probable loss associated with this class action complaint. As ComEd is unable to predict the ultimate outcome of this proceeding, actual damages may differ from the estimated amount recorded, which may be material to ComEd's results of operations, cash flows, and financial position.

***Fund Transfer Restrictions***

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.

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

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***

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.

***General***

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

***Supplemental Statement of Operations Information***

The following tables provide additional information about Exelon's Consolidated Statements of Operations and Comprehensive Income for the years ended December 31, 2014, 2013 and 2012.

| | For the year ended December 31, | | |
|---|---|---|---|
| | 2014 | 2013 | 2012 |
| **Taxes other than income** | | | |
| Utility (a) | $ 456 | $ 449 | $ 463 |
| Property | 396 | 302 | 227 |
| Payroll | 200 | 159 | 131 |
| Other | 102 | 185 | 198 |
| Total taxes other than income | $1,154 | $1,095 | $1,019 |

(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.

**Combined Notes to Consolidated Financial Statements—(Continued)**
**(Dollars in millions, except per share data unless otherwise noted)**

| | For the year ended December 31, 2014 | 2013 | 2012 |
|---|---|---|---|
| **Other, Net** | | | |
| Decommissioning-related activities: | | | |
| Net realized income on decommissioning trust funds [(a)]— | | | |
| Regulatory agreement units | $ 216 | $ 256 | $ 189 |
| Non-regulatory agreement units | 159 | 77 | 102 |
| Net unrealized gains on decommissioning trust funds— | | | |
| Regulatory agreement units | 180 | 406 | 386 |
| Non-regulatory agreement units | 134 | 146 | 105 |
| Net unrealized gains on pledged assets— | | | |
| Zion Station decommissioning | 29 | 7 | 73 |
| Regulatory offset to decommissioning trust fund-related activities [(b)] | (358) | (546) | (530) |
| Total decommissioning-related activities | 360 | 346 | 325 |
| Investment income | 1 | 8 | 20 |
| Long-term lease income | 24 | 28 | 29 |
| Interest income related to uncertain income tax positions | 40 | 24 | 15 |
| AFUDC—Equity | 21 | 22 | 17 |
| Credit Facility termination fees | — | — | (85) |
| Other | 9 | 32 | 32 |
| Other, net | $ 455 | $ 460 | $ 353 |

(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.

### *Supplemental Cash Flow Information*

The following tables provide additional information regarding Exelon's Consolidated Statements of Cash Flows for the years ended December 31, 2014, 2013 and 2012.

| For the year ended December 31, 2014 | 2014 | 2013 | 2012 |
|---|---|---|---|
| **Depreciation, amortization, accretion and depletion** | | | |
| Property, plant and equipment | $2,080 | $1,893 | $1,712 |
| Regulatory assets | 191 | 212 | 129 |
| Amortization of intangible assets, net | 44 | 48 | 40 |
| Amortization of energy contract assets and liabilities [(a)] | 135 | 430 | 1,110 |
| Nuclear fuel [(b)] | 1,073 | 921 | 848 |
| ARO accretion [(c)] | 345 | 275 | 240 |
| Total depreciation, amortization, accretion and depletion | $3,868 | $3,779 | $4,079 |

(a) Included in Operating revenues or Purchased power and fuel on the Registrants' Consolidated Statements of Operations and Comprehensive Income.
(b) Included in Purchased power and fuel expense on the Registrants' Consolidated Statements of Operations and Comprehensive Income.
(c) Included in Operating and maintenance expense on the Registrants' Consolidated Statements of Operations and Comprehensive Income.

**Combined Notes to Consolidated Financial Statements—(Continued)**
**(Dollars in millions, except per share data unless otherwise noted)**

| | For the year ended December 31, | | |
|---|---|---|---|
| | 2014 | 2013 | 2012 |
| **Cash paid (refunded) during the year:** | | | |
| Interest (net of amount capitalized) | $ 940 | $ 866 | $ 761 |
| Income taxes (net of refunds) | $ 314 | 112 | (171) |
| **Other non-cash operating activities:** | | | |
| Pension and non-pension postretirement benefit costs | $ 560 | $ 825 | 820 |
| Gain from equity method investments | — | (10) | — |
| Loss from equity method investments | 22 | — | — |
| Earnings from equity method investments | — | — | 91 |
| Provision for uncollectible accounts | 156 | 101 | 164 |
| Provision for excess and obsolete inventory | 5 | 9 | 6 |
| Stock-based compensation costs | 91 | 120 | 94 |
| Other decommissioning-related activity [(a)] | (132) | (169) | (145) |
| Energy-related options [(b)] | 122 | 104 | 160 |
| Amortization of regulatory asset related to debt costs | 11 | 12 | 18 |
| Amortization of rate stabilization deferral | 65 | 66 | 57 |
| Amortization of debt fair value adjustment | (23) | (34) | (34) |
| Merger-related commitments | 44 | — | 141 |
| Severance costs | — | — | 99 |
| Amortization of debt costs | 53 | 18 | 19 |
| Discrete impacts from EIMA [(c)] | 53 | (271) | (96) |
| Lower of cost or market inventory adjustment | 29 | — | — |
| Other | (2) | (53) | (30) |
| Total other non-cash operating activities | $ 1,054 | $ 718 | $1,364 |
| **Changes in other assets and liabilities:** | | | |
| Under/over-recovered energy and transmission costs | $ 47 | $ 12 | $ 71 |
| Other regulatory assets and liabilities | (167) | (64) | (404) |
| Cash deposits [(d)] | (241) | — | — |
| Other current assets | 7 | (165) | 213 |
| Other noncurrent assets and liabilities | (204) | 322 | (248) |
| Total changes in other assets and liabilities | $ (558) | $ 105 | $ (368) |
| **Non-cash investing and financing activities:** | | | |
| Change in ARC | $ 72 | $(128) | $ 781 |
| Change in capital expenditures not paid | 220 | (38) | 160 |
| Fair value of net assets recorded upon CENG consolidation [(f)] | (3,400) | — | — |
| Issuance of equity units [(g)] | 131 | — | — |
| Nuclear fuel procurement [(h)] | 70 | — | — |
| Consolidated VIE dividend to noncontrolling interest | — | 63 | 7,365 |
| Indemnification of like-kind exchange position [(i)] | — | — | — |

(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 primarily to cash deposits made to ISO's/RTO's.

(e) Includes $170 million of changes in capital expenditures not paid between December 31, 2014 and 2013 related to Antelope Valley.

(f) See Note 5—Investment in Constellation Energy Nuclear Group, LLC for additional information.

(g) Relates to the present value of the contract payments for the equity units issued by Exelon. See Note 19—Common Stock for additional information.

**Combined Notes to Consolidated Financial Statements—(Continued)**
**(Dollars in millions, except per share data unless otherwise noted)**

(h) Relates to the nuclear fuel procurement contracts for the purchase of fixed quantities of uranium, which was delivered to Generation on June 30, 2014 and September 24, 2014. Generation is required to make payments starting June 30, 2016, with the final payment being due no later than June 30, 2018.
(i) See Note 14—Income Taxes for discussion of the like-kind exchange tax position.

*DOE Smart Grid Investment Grant.* For the year ended December 31, 2014, PECO has included in the capital expenditures line item under investing activities of the cash flow statement capital expenditures of $2 million and reimbursements of $5 million related to PECO's DOE SGIG programs. 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, and reimbursements of $95 million, $37 million and $58 million, 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 Exelon at December 31, 2014 and 2013.

| December 31, 2014 | 2014 | 2013 |
|---|---|---|
| **Investments** | | |
| Equity method investments: | | |
| Financing trusts [(a)] | $ 22 | $ 22 |
| Keystone Fuels, LLC | — | 32 |
| Conemaugh Fuels, LLC | — | 21 |
| CENG | — | 1,925 |
| Safe Harbor | — | 285 |
| Malacha | — | 8 |
| Bloom Energy | 13 | — |
| Net Power | 9 | — |
| Sunnyside | 5 | — |
| Other equity method investments | 1 | 2 |
| Total equity method investments | 50 | 2,295 |
| Other investments: | | |
| Net investment in leases | 367 | 705 |
| Employee benefit trusts and investments [(b)] | 85 | 90 |
| Other investments [(c)] | 42 | 22 |
| Total investments | $544 | $3,112 |

(a) Includes investments in affiliated financing trusts, which were not consolidated within the financial statements of Exelon and are shown as investments 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.
(c) Includes cost method and available-for-sale investments.

The following tables provide additional information about liabilities of the Registrants at December 31, 2014 and 2013.

| December 31, 2014 | 2014 | 2013 |
|---|---|---|
| **Accrued expenses** | | |
| Compensation-related accruals [(a)] | $ 832 | $ 683 |
| Taxes accrued | 305 | 315 |
| Interest accrued | 240 | 234 |
| Severance accrued | 49 | 66 |
| Other accrued expenses | 113[(b)] | 335[(b)] |
| Total accrued expenses | $1,539 | $1,633 |

(a) Primarily includes accrued payroll, bonuses and other incentives, vacation and benefits.
(b) Includes $19 million and $228 million for amounts accrued related to Antelope Valley as of December 31, 2014 and December 31, 2013, respectively.

**Combined Notes to Consolidated Financial Statements—(Continued)**
**(Dollars in millions, except per share data unless otherwise noted)**

## 24. Segment Information

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. ComEd, PECO and BGE each represent a single reportable segment; as such, no separate segment information is provided for these Registrants. Exelon's CODM evaluates the performance of and allocates resources to ComEd, PECO and BGE based on net income and return on equity.

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 sales to its affiliates, 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, investments in gas and oil exploration and production activities, proprietary trading, distributed generation, 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

**Combined Notes to Consolidated Financial Statements—(Continued)**
**(Dollars in millions, except per share data unless otherwise noted)**

Shores, Wagner, and C.P. Crane Maryland generating stations, and other miscellaneous revenues, unrealized mark-to-market impact of economic hedging activities, and amortization of certain intangible assets relating to commodity contracts recorded at fair value are also not allocated to a region. Exelon and Generation do not use a measure of total assets in making decisions regarding allocating resources to or assessing the performance of these reportable segments.

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, 2014, 2013, and 2012 is as follows:

| | Generation [a] | ComEd | PECO | BGE [b] | Other [c] | Intersegment Eliminations | Exelon |
|---|---|---|---|---|---|---|---|
| **Operating revenues [d]:** | | | | | | | |
| 2014 | $17,393 | $ 4,564 | $3,094 | $3,165 | $1,285 | $ (2,072) | $27,429 |
| 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 |
| **Intersegment revenues [e]:** | | | | | | | |
| 2014 | $ 762 | $ 4 | $ 2 | $ 25 | $1,280 | $ (2,067) | $ 6 |
| 2013 | 1,367 | 3 | 1 | 13 | 1,237 | (2,607) | 14 |
| 2012 | 1,660 | 2 | 3 | 9 | 1,381 | (3,049) | 6 |
| **Depreciation and amortization** | | | | | | | |
| 2014 | $ 967 | $ 687 | $ 236 | $ 371 | $ 53 | $ — | $ 2,314 |
| 2013 | 856 | 669 | 228 | 348 | 52 | — | 2,153 |
| 2012 | 768 | 610 | 217 | 238 | 48 | — | 1,881 |
| **Operating expenses [d]:** | | | | | | | |
| 2014 | $16,923 | $ 3,586 | $2,522 | $2,726 | $1,353 | $ (2,071) | $25,039 |
| 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 |
| **Equity in earnings (losses) of unconsolidated affiliates** | | | | | | | |
| 2014 | $ (20) | $ — | $ — | $ — | $ — | $ — | $ (20) |
| 2013 | 10 | — | — | — | — | — | 10 |
| 2012 | (91) | — | — | — | — | — | (91) |
| **Interest expense, net:** | | | | | | | |
| 2014 | $ 356 | $ 321 | $ 113 | $ 106 | $ 169 | $ — | $ 1,065 |
| 2013 | 357 | 579 | 115 | 122 | 183 | — | 1,356 |
| 2012 | 301 | 307 | 123 | 111 | 86 | — | 928 |
| **Income (loss) before income taxes:** | | | | | | | |
| 2014 | $ 1,226 | $ 676 | $ 466 | $ 351 | $ (227) | $ (6) | $ 2,486 |
| 2013 | 1,675 | 401 | 557 | 344 | (191) | (13) | 2,773 |
| 2012 | 1,058 | 618 | 508 | (54) | (325) | (7) | 1,798 |
| **Income taxes:** | | | | | | | |
| 2014 | $ 207 | $ 268 | $ 114 | $ 140 | $ (63) | $ — | $ 666 |
| 2013 | 615 | 152 | 162 | 134 | (20) | 1 | 1,044 |
| 2012 | 500 | 239 | 127 | (23) | (215) | (1) | 627 |
| **Net income (loss):** | | | | | | | |
| 2014 | $ 1,019 | $ 408 | $ 352 | $ 211 | $ (164) | $ (6) | $ 1,820 |
| 2013 | 1,060 | 249 | 395 | 210 | (171) | (14) | 1,729 |
| 2012 | 558 | 379 | 381 | (31) | (110) | (6) | 1,171 |
| **Capital expenditures:** | | | | | | | |
| 2014 | $ 3,012 | $ 1,689 | $ 661 | $ 620 | $ 95 | $ — | $ 6,077 |
| 2013 | 2,752 | 1,433 | 537 | 587 | 86 | — | 5,395 |
| 2012 | 3,554 | 1,246 | 422 | 500 | 67 | — | 5,789 |
| **Total assets:** | | | | | | | |
| 2014 | $45,348 | $25,392 | $9,943 | $8,078 | $9,794 | $(11,741) | $86,814 |
| 2013 | 41,232 | 24,118 | 9,617 | 7,861 | 8,317 | (11,221) | 79,924 |

**Combined Notes to Consolidated Financial Statements—(Continued)**
**(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. For the year ended December 31, 2014, intersegment revenues for Generation include revenue from sales to PECO of $198 million and sales to BGE of $387 million in the Mid-Atlantic region, and sales to ComEd of $176 million in the Midwest region, which eliminate upon consolidation. For the year ended December 31, 2013, intersegment revenues for Generation include revenue from sales to PECO of $405 million and sales to BGE of $455 million in the Mid-Atlantic region, and sales to ComEd of $506 million 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, intersegment revenues for Generation include revenue from sales to PECO of $543 million and sales to BGE of $322 million in the Mid-Atlantic region, and sales to ComEd of $795 million 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.
(b) Amounts represent activity recorded at BGE from March 12, 2012, the closing date of the merger, through December 31, 2014.
(c) Other primarily includes Exelon's corporate operations, shared service entities and other financing and investment activities.
(d) For the years ended December 31, 2014, 2013 and 2012, utility taxes of $89 million, $79 million and $82 million, respectively, are included in revenues and expenses for Generation. For the years ended December 31, 2014, 2013 and 2012, utility taxes of $238 million, $241 million and $239 million, respectively, are included in revenues and expenses for ComEd. For the years ended December 31, 2014, 2013 and 2012, utility taxes of $128 million, $129 million and $141 million, respectively, are included in revenues and expenses for PECO. For the years ended December 31, 2014, December 31, 2013 and for the period of March 12, 2012 through December 31, 2012, utility taxes of $86 million, $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 and Comprehensive Income.

### Generation total revenues:

As of April 1, 2014, Generation total revenues and Generation total revenues net of purchased power and fuel expense includes 100% of the activity from CENG.

| | 2014 | | | 2013 | | | 2012 | | |
|---|---|---|---|---|---|---|---|---|---|
| | 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 | $ 5,265 | $ (6) | $ 5,259 | $ 5,182 | $ 22 | $ 5,204 | $ 5,082 | $(44) | $ 5,038 |
| Midwest | 4,467 | 8 | 4,475 | 4,280 | (10) | 4,270 | 4,824 | 24 | 4,848 |
| New England | 1,417 | 5 | 1,422 | 1,245 | (8) | 1,237 | 1,048 | 45 | 1,093 |
| New York | 843 | — | 843 | 735 | (21) | 714 | 582 | (25) | 557 |
| ERCOT | 938 | (3) | 935 | 1,222 | (6) | 1,216 | 1,365 | 2 | 1,367 |
| Other Regions (b) | 1,319 | (10) | 1,309 | 946 | 22 | 968 | 755 | 78 | 833 |
| Total Revenues for Reportable Segments | $14,249 | $ (6) | $14,243 | $13,610 | $ (1) | $13,609 | $13,656 | $ 80 | $13,736 |
| Other (c) | 3,144 | 6 | 3,150 | 2,020 | 1 | 2,021 | 781 | (80) | 701 |
| Total Generation Consolidated Operating Revenues | $17,393 | $— | $17,393 | $15,630 | $— | $15,630 | $14,437 | $— | $14,437 |

(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 $289 million, $767 million, and $1,505 million for the years ended December 31, 2014, 2013, and 2012, respectively, and elimination of intersegment revenues.

**Combined Notes to Consolidated Financial Statements—(Continued)**
**(Dollars in millions, except per share data unless otherwise noted)**

**Generation total revenues net of purchased power and fuel expense:**

| | 2014 | | | 2013 | | | 2012 | | |
|---|---|---|---|---|---|---|---|---|---|
| | 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 | $3,466 | $ (49) | $3,417 | $3,273 | $ (3) | $3,270 | $3,477 | $(44) | $3,433 |
| Midwest | 2,580 | 14 | 2,594 | 2,585 | 1 | 2,586 | 2,974 | 24 | 2,998 |
| New England | 432 | (81) | 351 | 217 | (32) | 185 | 151 | 45 | 196 |
| New York | 457 | 26 | 483 | 14 | (18) | (4) | 101 | (25) | 76 |
| ERCOT | 573 | (256) | 317 | 604 | (168) | 436 | 403 | 2 | 405 |
| Other Regions [b] | 611 | (284) | 327 | 334 | (133) | 201 | 53 | 78 | 131 |
| Total Revenues net of purchased power and fuel expense for Reportable Segments | $8,119 | $(630) | $7,489 | $7,027 | $(353) | $6,674 | $7,159 | $ 80 | $7,239 |
| Other [c] | (651) | 630 | (21) | 406 | 353 | 759 | 217 | (80) | 137 |
| Total Generation Revenues net of purchased power and fuel expense | $7,468 | $ — | $7,468 | $7,433 | $ — | $7,433 | $7,376 | $— | $7,376 |

(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 $124 million, $488 million, and $1,098 million, for the years ended December 31, 2014, 2013, and 2012, respectively, and the elimination of intersegment revenue net of purchased power and fuel expense.

**Combined Notes to Consolidated Financial Statements—(Continued)**
**(Dollars in millions, except per share data unless otherwise noted)**

## 25. Related Party Transactions

The financial statements of Exelon include related party transactions as presented in the tables below:

| | For the Years Ended December 31, 2014 | 2013 | 2012 |
|---|---|---|---|
| Operating revenues from affiliates: | | | |
| PECO [a] | $ 1 | $ 10 | $ 6 |
| CENG [b] | 17 | 56 | 42 |
| BGE [a] | 5 | 4 | — |
| Total operating revenues from affiliates | $ 23 | $ 70 | $ 48 |
| Purchase power and fuel from affiliates: | | | |
| CENG [c] | $282 | $ 992 | $ 793 |
| Keystone Fuels, LLC [d] | 138 | 144 | 119 |
| Conemaugh Fuels, LLC [d] | 99 | 98 | 101 |
| Safe Harbor Water Power Corp [d] | 12 | 22 | 23 |
| Total purchase power and fuel from affiliates | $531 | $1,256 | $1,036 |
| 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 | 16 | 12 |
| Total interest expense to affiliates, net | $ 41 | $ 41 | $ 37 |
| Earnings (losses) in equity method investments: | | | |
| CENG [e] | $ (19) | $ 9 | $ (99) |
| Qualifying facilities and domestic power projects | (1) | 1 | 8 |
| Total earnings (losses) in equity method investments | $ (20) | $ 10 | $ (91) |

| | December 31, 2014 | 2013 |
|---|---|---|
| Receivables from affiliates (current): | | |
| CENG [b] | $— | $ 3 |
| Payables to affiliates (current): | | |
| CENG [c] | $— | $ 85 |
| ComEd Financing III | 4 | 4 |
| PECO Trust III | 1 | 1 |
| BGE Capital Trust II | 3 | 4 |
| Keystone Fuels, LLC [d] | — | 12 |
| Conemaugh Fuels, LLC [d] | — | 9 |
| Other | — | 1 |
| Total payables to affiliates (current) | $ 8 | $116 |
| 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.

**Combined Notes to Consolidated Financial Statements—(Continued)**
**(Dollars in millions, except per share data unless otherwise noted)**

(b) Beginning in 2012, Generation entered into a power services agency agreement (PSAA) with the CENG plants, which as of April 1, 2014, was amended and extended until the permanent cessation of power generation by the CENG generation plants. The PSAA is an 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. On April 1, 2014, Generation and CENG entered into 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 part of the Generation nuclear fleet. 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. Beginning in 2012, Generation had a PPA under which it purchased 85% of the nuclear plant output owned by CENG that was not sold to third parties under pre-existing 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). Beginning April 1, 2014, sales to Generation are eliminated in consolidation. For further information regarding the Investment in CENG, see Note 5—Investment in Constellation Energy Nuclear Group, LLC.

(d) During 2014, Generation closed the sale of Safe Harbor Water Power Corporation, Keystone Fuels, LLC, and Conemaugh Fuels LLC. Generation recorded purchase power and fuel costs from affiliates related to these generating assets during the time these assets were still partially owned by Generation. See Note 4—Mergers, Acquisitions, and Dispositions for more information.

(e) Prior to April 1, 2014, Generation's total gain (loss) in equity method investments includes equity investment income (loss) and amortization of the basis difference established as a result of purchase accounting applied upon Constellation merger in 2012. CENG was fully consolidated on April 1, 2014. 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.

## 26. Quarterly Data (Unaudited)

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 | |
|---|---|---|---|---|---|---|
| | 2014 | 2013 | 2014 | 2013 | 2014 | 2013 |
| Quarter ended: | | | | | | |
| March 31 | $7,237 | $6,082 | $ 168[(a)] | $ 513[(b)] | $ 90 | $ (4)[(c)] |
| June 30 | 6,024 | 6,141 | 842[(a)] | 1,005 | 522 | 490 |
| September 30 | 6,912 | 6,502 | 1,739[(a)] | 1,262[(b)] | 993 | 738 |
| December 31 | 7,255 | 6,163 | 348 | 889 | 18[(d)] | 495 |

(a) In the first, second, and third quarter of 2014, Exelon reclassified $5 million, $13 million, and $339 million, respectively, to Operating income for presentation purposes in Exelon's Consolidated Statements of Operations and Comprehensive Income. The reclassifications did not affect Exelon's Net (Loss) Income on Common Stock.

(b) In the first and third quarter of 2013, Exelon reclassified $5 million and $8 million, respectively, to Operating income for presentation purposes in Exelon's Consolidated Statements of Operations and Comprehensive Income. The reclassifications did not affect Exelon's Net (Loss) Income on Common Stock.

(c) Includes $265 million of interest expense related to 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.

(d) Includes charges to earnings related to the impairments of certain generating assets which were held for sale and certain Upstream exploration assets. See Note 8—Impairment of Long-Lived Assets of the Combined Notes to Consolidated Financial Statements for additional information.

| | Average Basic Shares Outstanding (in millions) | | Net (Loss) Income per Basic Share | |
|---|---|---|---|---|
| | 2014 | 2013 | 2014 | 2013 |
| Quarter ended: | | | | |
| March 31 | 858 | 855 | $0.10 | $(0.01) |
| June 30 | 860 | 856 | 0.61 | 0.57 |
| September 30 | 861 | 857 | 1.15 | 0.86 |
| December 31 | 861 | 856 | 0.02 | 0.60 |

**Combined Notes to Consolidated Financial Statements—(Continued)**
**(Dollars in millions, except per share data unless otherwise noted)**

| | Average Diluted Shares Outstanding (in millions) | | Net (Loss) Income per Diluted Share | |
|---|---|---|---|---|
| | 2014 | 2013 | 2014 | 2013 |
| Quarter ended: | | | | |
| March 31 | 861 | 855 | $0.10 | $(0.01) |
| June 30 | 864 | 860 | 0.60 | 0.57 |
| September 30 | 863 | 860 | 1.15 | 0.86 |
| December 31 | 868 | 860 | 0.02 | 0.59 |

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

| | 2014 | | | | 2013 | | | |
|---|---|---|---|---|---|---|---|---|
| | Fourth Quarter | Third Quarter | Second Quarter | First Quarter | Fourth Quarter | Third Quarter | Second Quarter | First Quarter |
| High price | $38.93 | $36.26 | $37.73 | $33.94 | $30.59 | $32.42 | $37.80 | $34.56 |
| Low price | 33.07 | 30.66 | 33.11 | 26.45 | 26.64 | 29.42 | 29.84 | 29.10 |
| Close | 37.08 | 34.09 | 36.48 | 33.56 | 27.39 | 29.64 | 30.88 | 34.48 |
| Dividends | 0.310 | 0.310 | 0.310 | 0.310 | 0.310 | 0.310 | 0.310 | 0.525 |

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**UNITED STATES**
**SECURITIES AND EXCHANGE COMMISSION**
**Washington, D.C. 20549**

# SCHEDULE 14A

**Proxy Statement Pursuant to Section 14(a)**
**of the Securities Exchange Act of 1934**
**(Amendment No. )**

Filed by the Registrant ☒ Filed by a Party other than the Registrant ☐

Check the appropriate box:

☒ Preliminary Proxy Statement

☐ **CONFIDENTIAL, FOR USE OF THE COMMISSION ONLY (AS PERMITTED BY RULE 14a-6(e)(2))**

☐ Definitive Proxy Statement

☐ Definitive Additional Materials

☐ Soliciting Material Pursuant to §240.14a-12

EXELON CORPORATION

(Name of Registrant as Specified In Its Charter)

(Name of Person(s) Filing Proxy Statement, if other than the Registrant)

Payment of Filing Fee (Check the appropriate box):

☒ No fee required.

☐ Fee computed on table below per Exchange Act Rules 14a-6(i)(1) and 0-11.

(1) Title of each class of securities to which transaction applies:

(2) Aggregate number of securities to which transaction applies:

(3) Per unit price or other underlying value of transaction computed pursuant to Exchange Act Rule 0-11 (set forth the amount on which the filing fee is calculated and state how it was determined):

(4) Proposed maximum aggregate value of transaction:

(5) Total fee paid:

☐ Fee paid previously with preliminary materials.

☐ Check box if any part of the fee is offset as provided by Exchange Act Rule 0-11(a)(2) and identify the filing for which the offsetting fee was paid previously. Identify the previous filing by registration statement number, or the Form or Schedule and the date of its filing.

(1) Amount Previously Paid:

(2) Form, Schedule or Registration Statement No.:

(3) Filing Party:

(4) Date Filed:

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Exelon.

March 19, 2015

# NOTICE OF THE ANNUAL MEETING AND 2015 PROXY STATEMENT

To the shareholders of Exelon Corporation:

Our annual meeting of shareholders will be held on Tuesday, April 28, 2015 at 9:00 a.m. Central Time at Exelon Corporation headquarters, 10 S. Dearborn, Chicago, Illinois to:

1) Elect director nominees named in the attached proxy statement;
2) Ratify PricewaterhouseCoopers LLP as Exelon's independent auditor for 2015;
3) Approve the compensation of our named executive officers as disclosed in the attached proxy statement;
4) Approve the performance measures included in Exelon Corporation's 2011 Long-Term Incentive Plan;
5) Approve the management proposal regarding proxy access;
6) Vote on a shareholder proposal regarding proxy access, if properly presented at the meeting; and
7) Conduct any other business that properly comes before the meeting.

Shareholders of record as of March 10, 2015 are entitled to vote at the annual meeting.

On or about March 19, 2015, we will mail to our shareholders a Notice Regarding the Availability of Proxy Materials, which will indicate how to access our proxy materials on the Internet. By furnishing the Notice Regarding the Availability of Proxy Materials we are lowering the costs and reducing the environmental impact of our annual meeting.

Bruce G. Wilson

Bruce G. Wilson
Senior Vice President,
Deputy General Counsel and Corporate Secretary

**Your vote is important. We encourage you to vote promptly.
Internet and telephone voting are available through 11:59 p.m.
Eastern Time on April 27, 2015.**

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# Proxy Statement Summary

We are providing these proxy materials in connection with the solicitation by the board of directors of Exelon Corporation ("Exelon," the "company," "we," "us," or "our"), a Pennsylvania corporation, of proxies to be voted at our 2015 annual meeting of shareholders and at any adjournment or postponement. The annual meeting of shareholders will take place on April 28, 2015 at 9:00 a.m. Central Time at Exelon Corporation headquarters, 10 S. Dearborn, Chicago, Illinois.

## MATTERS FOR SHAREHOLDER VOTING

At this year's annual meeting, we are asking our shareholders to vote on the following matters:

**Proposal 1: Election of Directors**

The board of directors recommends a vote FOR the election of the director nominees named in this proxy statement. See pages 1 through 11 for further information on the nominees.

**Proposal 2: Appointment of PricewaterhouseCoopers LLP for 2015**

The board of directors recommends a vote FOR this proposal. See page 32 for details.

**Proposal 3: Advisory Approval of Executive Compensation**

The board of directors recommends a vote FOR this proposal. See pages 33-76 for details.

**Proposal 4: Approve Performance Measures included in Exelon Corporation's 2011 Long-Term Incentive Plan**

The board of directors recommends a vote FOR this proposal. See pages 77-80 for details.

**Proposal 5: Approve Management Proposal regarding Proxy Access**

The board of directors recommends a vote FOR this proposal. See pages 81-85 for details.

**Proposal 6: Shareholder Proposal regarding Proxy Access**

The board of directors recommends a vote AGAINST this proposal. See pages 86-88 for details.

The board of directors knows of no other matters to be presented for action at the annual meeting. If any matter is presented from the floor of the annual meeting, the individuals serving as proxies intend to vote on these matters in the best interest of all shareholders. Your signed proxy card gives this authority to Darryl M. Bradford and Bruce G. Wilson.

Please refer to the material on pages 89-94 for information about how to cast your votes, who may attend the meeting, and other frequently asked questions.

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# Proxy Statement Summary

## GOVERNANCE HIGHLIGHTS

Exelon is committed to maintaining the highest standards of corporate governance. Strong corporate governance practices help us achieve our performance goals and maintain the trust and confidence of our investors, employees, customers, regulatory agencies and other stakeholders. Our corporate governance practices are described in more detail on pages 9-27 and in our Corporate Governance Principles which are available on the Exelon website at www.exeloncorp.com on the corporate governance page under the Investors tab.

| | |
|---|---|
| Director Independence | • 11 of our 13 nominees are independent.<br>• Our CEO is the only management director.<br>• During 2014, all of our board committees (except the generation oversight committee and investment oversight committee) were composed exclusively of independent directors. |
| Board Leadership | • We have an independent Lead Director, selected by the independent directors.<br>• The Lead Director serves as non-exclusive liaison between management and the other non-management directors.<br>• The positions of Chairman and CEO are separated |
| Executive Sessions | • The independent directors regularly meet in executive sessions without management, at which the Lead Director presides. |
| Board Oversight of Risk Management | • Our board reviews Exelon's systematic approach to identifying and assessing risks faced by Exelon and our business units.<br>• The board considers enterprise risk in connection with emerging trends or developments and the evaluation of capital investments and business opportunities.<br>• The board's finance and risk committee oversees our risk management strategy, policies and practices and financial condition and risk exposures. |
| Stock Ownership Requirements | • Our independent directors must hold at least 15,000 shares of Exelon common stock within five years after joining the board.<br>• Our CEO must, after five years of employment, hold Exelon Common Stock valued at six times base salary.<br>• Executive vice presidents and higher officers must, within five years after employment or September 30, 2012, hold Exelon Common Stock, valued at three times base salary. |
| Board Practices | • Our board annually reviews its effectiveness as a group.<br>• Continuing director education is provided during regular board and committee meetings.<br>• Directors may not stand for election after age 75. |
| Accountability | • All directors stand for election annually.<br>• In uncontested elections, directors must be elected by a majority of votes cast. |

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# Proxy Statement Summary

## 2014 EXECUTIVE COMPENSATION HIGHLIGHTS

### 1 STRONG COMPANY PERFORMANCE

- Exelon's share price was up 35.4% for the year, with a total shareholder return of 40.6% (including reinvested dividends), outpacing the S&P 500 (14.0%) and our 20 company peer group (23.3%).
- Exelon Utilities completed the year with high performance across key operating areas including safety (top decile) and top quartile performance in all three utilities (BGE, ComEd and PECO) for both outage frequency and duration. See chart on page 53 for full details.
- Exelon Generation had exceptional plant performance in 2014, including nuclear capacity factor of over 94%, power dispatch match of nearly 97%, and renewables (wind and solar) energy capture of 95%.

### 2 STRONG EXECUTION OF M&A STRATEGY

- Executed a merger agreement to acquire Pepco Holdings Inc. (PHI) for $6.8 billion, with an anticipated closing in the second or third quarter of 2015.
- Divested five non-core power plants to yield $1.8 billion of pre-tax proceeds ($1.4 billion after-tax).
- Acquired two Midwest energy marketers (ProLiance and Integrys), virtually doubling the number of customers by adding over 1.2 million residential and commercial and industrial customers.
- Invested in a portfolio of Bloom Energy fuel cell products to further the Bloom partnership and advance Exelon's objectives in building its distributed generation business.

### 3 DECREASE IN CEO REPORTED COMPENSATION

- As reported in the summary compensation table on page 60, CEO pay decreased 13%, or 20% excluding the change in pension value and deferred compensation earnings. This decrease was attributed to the one-time, performance-based transition award. For more details refer to the transition award section on page 53.
- For 2014, CEO target total direct compensation was calibrated to approximate the market median of the 20 company peer group. For additional information, please see CEO pay-at-glance section on pages 39-41.

### 4 COMMITMENT TO SHAREHOLDER ENGAGEMENT

- The company met with investors holding approximately 46% of the outstanding shares (up from about 35% the prior year).
- No material plan design changes made for 2014, as shareholders expressed support for the design changes that we implemented in 2013. See page 41 for details.
- For 2015, the company is making a few enhancements based on shareholder feedback received during the fall 2014 outreach, including increasing the CEO's stock ownership target from 5X to 6X to align more closely with market practice.

### 5 STRONG INCENTIVE GOAL RIGOR

- The 2014 performance share goals, which are part of the LTI Program, were set at a level that resulted in eight of the ten underlying metrics being more challenging than the prior year, aligning with top quartile and top decile industry performance standards as shown on page 53.

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**Cautionary Statements Regarding Forward-Looking Information**

This proxy statement contains certain 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 Exelon Corporation include those factors discussed herein, as well as the items discussed in (1) Exelon's 2014 Annual Report on Form 10-K in (a) ITEM 1A. Risk Factors, (b) ITEM 7. Management's Discussion and Analysis of Financial Condition and Results of Operations and (c) ITEM 8. Financial Statements and Supplementary Data: Note 22 and (2) other factors discussed in filings with the SEC by Exelon. Readers are cautioned not to place undue reliance on these forward-looking statements, which apply only as of the date of this proxy statement. Exelon does not undertake any obligation to publicly release any revision to its forward-looking statements to reflect events or circumstances after the date of this proxy statement.

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# Election of Directors

## PROPOSAL 1: ELECTION OF DIRECTORS

## DIRECTOR NOMINEES

Upon the recommendation of the corporate governance committee, the board nominated the 13 candidates named below for election as directors, each to serve a term ending with the annual meeting in 2016. Each of the nominees has agreed to be named in this proxy statement and to serve as a director, if elected. If any director is unable to stand for election, the board may reduce the number of directors or designate a substitute. In that case, shares represented by proxies may be voted for a substitute director. Exelon does not expect that any director nominee will be unable to serve.

The corporate governance committee believes that the current membership of the board represents an effective mix of directors in terms of the range of backgrounds and experience and diversity. The current board consists of directors who range in age from 56 to 74, with an average age of 64.2 and a median age of 67. The tenure of the directors is similarly varied, with one director having served since the company's creation in 2000, one since 2002, one since 2005, two since 2007, one since 2008, one since 2009, five since 2012 and one joining in 2013. Four directors come from the Chicago area, one from the Philadelphia area, while eight come from other parts of the country including major metropolitan areas such as New York and Washington, D.C.

The current directors have a wide diversity of experiences that fill the needs of the board and its committees. Eight directors are current or former CEOs of corporations; one is the former CEO of a university. Two directors have strong nuclear experience. Six directors have experience in banking and investment management. One has served in government and one has flag officer military experience. Individual directors have experience or expertise in accounting, utility regulation and operations, and environmental matters, law, the economics of energy and government affairs.

The board of directors held eight meetings during 2014. The board also attended a two-day strategy retreat with the senior officers of Exelon and subsidiary companies. All directors attended at least 75% of all board and committee meetings that they were eligible to attend, with an average attendance of approximately 98.36% across all directors for all board and committee meetings. Although Exelon does not have a formal policy requiring attendance at the annual shareholders meeting, all directors generally attend the annual meeting. Ms. Sue Gin who served as a director since 2000 passed away on September 26, 2014. Hon. Nelson Diaz, who served as a director since 2004, declined to stand for re-election to the board.

**The board of directors unanimously recommends a vote "FOR" each of the director nominees below.**

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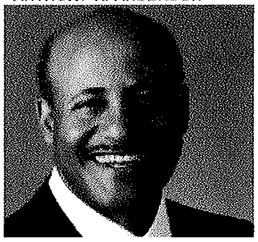
# Election of Directors

**ANTHONY K. ANDERSON**



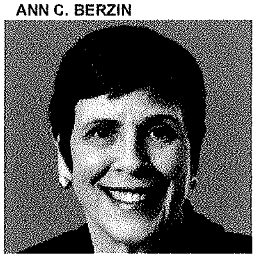
**Retired Vice Chair and Midwest Area Managing Partner of Ernst & Young**

**Age:** 59
**Director since:** 2013

**Committees:**
Chair-Audit Committee
Member-Finance and Risk Committee
Member-Generation Oversight Committee

In 2012, Mr. Anderson retired as the Vice Chair and Midwest Area Managing Partner of Ernst & Young, after a 35-year career with E&Y. In that capacity, Mr. Anderson oversaw a practice of 3,500 audit, tax, and transaction professionals serving clients through the Midwest. Mr. Anderson also served for six years in the Los Angeles area as managing partner of E&Y's Pacific Southwest region. Mr. Anderson also served as a member of Ernst & Young's governing body, the Americas Executive Board. Mr. Anderson currently serves on the boards of AAR Corp. (aerospace and defense), where he serves on the audit and compensation committees; Avery Dennison Corporation (labeling and packaging materials), where he serves on the audit and finance committee; and First American Financial Corporation (financial services), where he serves on the governance and nominating committee. Mr. Anderson also served as a director of the Federal Reserve Bank of Chicago from 2008-2010. Mr. Anderson is the chairman of the board of the Perspectives Charter School. He is also a member of the boards of Chicago Urban League, The Chicago Council on Global Affairs, the Regional Transportation Authority and World Business Chicago. In Los Angeles, Mr. Anderson served as chairman of Town Hall Los Angeles, the Children's Bureau of Southern California, and the California Science Center. Mr. Anderson is a member of the American, California, and Illinois Institute of Certified Public Accountants. Mr. Anderson's experience as the vice chair of a global professional services firm and his training and experience as an audit partner and certified public accountant enhance his contribution to the Exelon board and add value to his experience on the audit, finance and risk and generation oversight committees.

**ANN C. BERZIN**



**Former Chairman and Chief Executive Officer of Financial Guaranty Insurance Company (FGIC)**

**Age:** 62
**Director since:** 2012

**Committees:**
Member-Audit Committee
Member-Finance and Risk Committee

Ms. Berzin has been a director of Exelon since March 12, 2012. Previously, Ms. Berzin served as a director of Constellation Energy Group from 2008 through March 2012 when Constellation merged with Exelon. From 1992 to 2001, Ms. Berzin served as Chairman and Chief Executive Officer of Financial Guaranty Insurance Company (FGIC), an insurer of municipal bonds, asset-backed securities and structured finance obligations. Ms. Berzin joined FGIC in 1985 as its General Counsel following seven years of securities law practice in New York City. Ms Berzin is a director of Ingersoll-Rand plc, Chair of its finance committee, and a member of its audit committee, and previously served as a director of Kindred Healthcare, Inc. (healthcare services) from 2006-2012. Ms. Berzin has broad business and executive leadership experience, as well as expertise in the financial services sector, which is particularly valuable in the area of risk management. Ms. Berzin also serves on the board of Baltimore Gas and Electric Company ("BGE"), an Exelon subsidiary.

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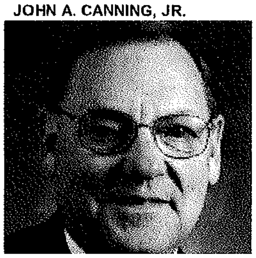
# Election of Directors

**JOHN A. CANNING, JR.**



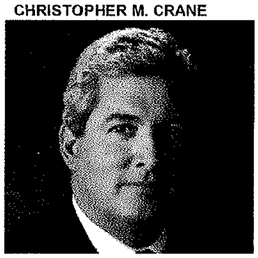
**Chairman and co-founder of Madison Dearborn Partners, LLC**

**Age:** 70
**Director since:** 2008

**Committees:**
Chair-Compensation and Leadership Development Committee
Member-Corporate Governance Committee

Mr. Canning is the Chairman and co-founder of Madison Dearborn Partners, LLC ("MDP"), which specializes in management buyout and growth equity investing. MDP has raised investment funds with more than $18 billion in limited partner commitments from over 400 endowments, pension funds and other sophisticated investors. MDP has made significant investments in the energy and power industry. Prior to co-founding Madison Dearborn Partners, Mr. Canning spent 24 years with First Chicago Corporation, where he managed the bank's venture investments. Mr. Canning has over 34 years of experience in private equity investing, including reviewing financial statements and audit results and making investment and acquisition decisions. Mr. Canning is a former director and Chairman of the Federal Reserve Bank of Chicago, giving him insight into economic trends important to the business of Exelon. Mr. Canning also serves on the board of Corning, Inc., a specialty glass and ceramics producer. Mr. Canning has also served on the board of directors of Jefferson Smurfit Group plc and on the audit committees of several charitable organizations, including the Irish Pension Reserve Fund. In addition to his business experience, he also has a law degree. Mr. Canning is a recognized leader in the Chicago business community with knowledge of the economy of the Midwestern United States and the northern Illinois communities that Exelon serves. Mr. Canning's business experience and service on the boards of other companies and organizations enable him to contribute to the work of the Exelon board. Mr. Canning's experience in banking and in managing investments, and his experience on the audit committees of other organizations, make him a valued member of the compensation and leadership development committee and the corporate governance committee.

**CHRISTOPHER M. CRANE**



**President and Chief Executive Officer of Exelon Corporation**

**Age:** 56
**Director since:** 2012

**Committees:**
Member-Generation Oversight Committee
Member-Investment Oversight Committee

Mr. Crane is President and Chief Executive Officer of Exelon Corporation since March 12, 2012. Previously, he served as President and Chief Operating Officer, Exelon; President and Chief Operating Officer, Exelon Generation since 2008. In that role, he oversaw one of the U.S. industry's largest portfolios of electric generating capacity, with a multi-regional reach and the nation's largest fleet of nuclear power plants. He directed a broad range of business including major acquisitions, transmission strategy, cost management initiatives, oversight of major capital programs, generation asset optimization and generation development. Mr. Crane is one of the leading executives in the electric utility and power industries. Mr. Crane served as a director of Aleris International Inc. from 2010 through October 2013 (manufacture and sale of aluminum rolled and extruded products), where he served on the compensation committee and as the chair of the nominating and corporate governance committee. He is a member of the executive committee of the Edison Electric Institute and the board of directors of the Institute of Nuclear Power Operations, the industry organization promoting the highest levels of safety and reliability in nuclear plant operation. He is vice chairman of the Nuclear Energy Institute, the nation's nuclear industry trade association, where he has also served as chairman of the New Plant Oversight Committee and as a member of the Nuclear Strategic Issues Advisory Committee, the Nuclear Fuel Supply Committee and the Materials Initiative Group. Mr. Crane also serves as chair of the boards of directors of Exelon subsidiaries BGE, Commonwealth Edison Company ("ComEd") and PECO Energy Company ("PECO").

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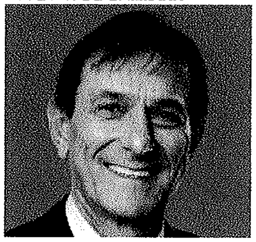
# Election of Directors

**YVES C. DE BALMANN**



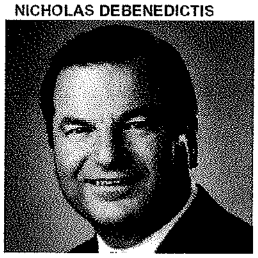
**Former Co-Chairman of Bregal Investments LP**

**Age:** 68
**Director since:** 2012

**Committees:**
Member-Audit Committee
Member-Compensation and Leadership Development Committee
Member-Finance and Risk Committee

Mr. de Balmann has been a director of Exelon since March 12, 2012. Mr. de Balmann served as a director of Constellation Energy Group from 2003 through March 2012 when Constellation merged with Exelon. Mr. de Balmann served as the Co-Chairman of Bregal Investments LP, a private equity investing firm, from September 2002 through December 2012. He was Vice-Chairman of Bankers Trust Corporation, in charge of Global Investment Banking, until its merger with Deutsche Bank in 1999 when he became Co-Head of Deutsche Bank's Global Investment Bank, and Co-Chairman and Co-Chief Executive Officer of Deutsche Banc Alex. Brown from June 1999 to April 2001, and then a Senior Advisor to Deutsche Bank AG from April 2001 to June 2003. Mr. de Balmann served as a director of Laureate Education, Inc. through December 2014; and he is non-executive Chairman of Conversant Intellectual Property Management. Mr. de Balmann has extensive experience in corporate finance, including the derivatives and capital markets.

**NICHOLAS DEBENEDICTIS**



**Chairman, President and Chief Executive Officer of Aqua America Inc.**

**Age:** 69
**Director since:** 2002

**Committees:**
Member-Corporate Governance Committee
Member-Finance and Risk Committee
Member-Generation Oversight Committee

Mr. DeBenedictis is the Chairman (since 1993), President and Chief Executive Officer (since 1992) of Aqua America Inc., a water utility with operations in 10 states. Aqua America is the second largest U.S.-based, publicly-traded water and wastewater company in the country. As CEO, Mr. DeBenedictis has experience in dealing with many of the same development, land use and utility regulatory issues that affect Exelon and its subsidiaries. Mr. DeBenedictis also has extensive experience in environmental regulation and economic development, having served in two cabinet positions in the Pennsylvania government, as Secretary of the Pennsylvania Department of Environmental Resources and as Director of the Office of Economic Development. He also spent eight years with the U.S. Environmental Protection Agency and was President of the Greater Philadelphia Chamber of Commerce for three years. Mr. DeBenedictis has also served as a director of P.H. Glatfelter, Inc. (global supplier of specialty papers and engineered products) since 1995, where he has served on the audit, compensation and finance, and nominating and corporate governance committees and currently serves as the chair of the finance committee and on the compensation committee. Mr. DeBenedictis served as a director of Met-Pro Corporation (global provider of solutions and products for product recovery, pollution control, and fluid handling applications) (1997-February 2010). While a director of Met-Pro, he served as presiding independent director, chair of the corporate governance and nominating committee and a member of the audit committee. Mr. DeBenedictis has a master's degree in environmental engineering and science. As a leader in the greater Philadelphia business community, he has knowledge of the communities and local economies served by PECO. Mr. DeBenedictis' contribution to the Exelon board is enhanced by his experience as the CEO of a public company, his experience on the boards of other companies, his experience as a utility executive, and his experience with environmental regulation, all of which bring useful perspectives to the Exelon board's finance and risk committee and the generation oversight committee. His prior experience as the presiding director and chair of the corporate governance committee of another public company offers additional insight to the functions of the Exelon corporate governance committee. Mr. DeBenedictis also serves on the boards of ComEd and PECO, which are Exelon subsidiaries.

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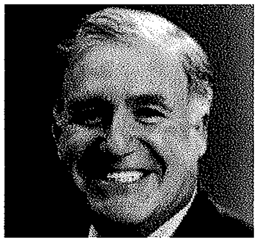
# Election of Directors

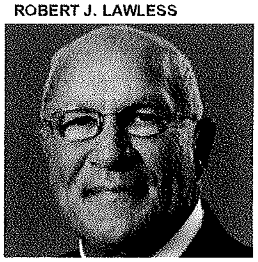
**PAUL L. JOSKOW, PH. D.**



**President of the Alfred P. Sloan Foundation**
**Age:** 67
**Director since:** 2007
**Committees:**
Member-Audit Committee
Member-Finance and Risk Committee
Member-Investment Oversight Committee

Dr. Joskow has been the President of the Alfred P. Sloan Foundation since January 1, 2008. The Sloan Foundation is a philanthropic institution that supports research and education in science, technology and economic performance. He is also the Elizabeth and James Killian Professor of Economics and Management Emeritus at the Massachusetts Institute of Technology (MIT). Dr. Joskow joined the MIT faculty in 1972 and served as head of the MIT Department of Economics (1994-1998) and Director of the MIT Center for Energy and Environmental Policy Research (1999-2007). At MIT he was engaged in teaching and research in the areas of industrial organization, energy and environmental economics, competition policy, and government regulation of industry for over 35 years. Much of his research and consulting activity has focused on the electric power industry, electricity pricing, fuel supply, demand, generating technology, and regulation. He is a Fellow of the American Academy of Arts and Sciences, the Econometric Society and a Distinguished Fellow of the American Economic Association. He has served on the U.S. Environmental Protection Agency's ("EPA") Acid Rain Advisory Committee, on the Environmental Economics Committee of EPA's Science Advisory Board, and on the National Commission on Energy Policy. He presently serves on the Secretary of Energy Advisory Board. He served as the Chair of the National Academies Board of Science, Technology and Economic Policy through March 1, 2015. He is also a Trustee of the Putnam Mutual Funds. In addition to his teaching, research, publishing and consulting activities, he has experience in the energy business, serving as a director of New England Electric System, a public utility holding company (1987-2000), until it was acquired by National Grid. He then served as a director of National Grid plc, an international electric and gas utility holding company, and one of the largest investor-owned utilities in the world (2000-2007). Dr. Joskow served as a director of TransCanada Corporation from 2004 until March 2013. TransCanada is an energy infrastructure company with gas pipelines, oil pipelines, electric power operations, and natural gas storage facilities. He served on the audit and governance committees of TransCanada. He previously served on the audit committee of National Grid (2000-2005) and was chair of its finance committee until 2007. He also served on the audit committee of New England Electric System and as the chair of the audit committee of the Putnam Mutual Funds (2002-2005).

**ROBERT J. LAWLESS**



**Former Chairman of the Board of McCormick & Company, Inc.**

**Age:** 68
**Director since:** 2012

**Committees:**
Chair-Corporate Governance Committee
Member-Compensation and Leadership Development Committee

Mr. Robert J. Lawless has been a director of Exelon since March 12, 2012. Mr. Lawless served as a director of Constellation Energy Group from 2002 through March 2012 when Constellation merged with Exelon. Mr. Lawless served as Chairman of the Board of McCormick & Company, Inc. (food manufacturing industry) from January 1997 until March 2009, having also served as President until December 2006 and Chief Executive Officer until January 2008, and is now retired. He is also a director of The Baltimore Life Insurance Company. Mr. Lawless has extensive executive leadership and strategic planning experience. As a former chief executive officer of a public company, he can provide a critical perspective on issues affecting public companies. Mr. Lawless serves on the compensation and leadership development committee and as the chair of the corporate governance committee.

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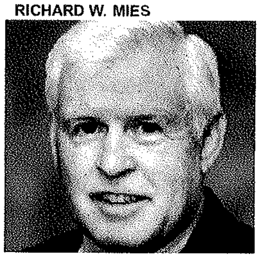
# Election of Directors

**RICHARD W. MIES**

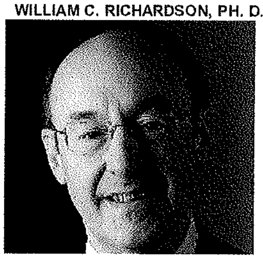


**President and Chief Executive Officer of The Mies Group, Ltd.**

**Age:** 70
**Director since:** 2009
**Committees:**
Chair-Generation Oversight Committee
Member-Audit Committee
Member-Corporate Governance Committee (through January 28, 2014)
Member-Finance & Risk Committee

Admiral Mies is President and Chief Executive Officer of The Mies Group, Ltd, a private consulting firm that provides strategic planning and risk assessment advice and assistance to clients on international security, energy, defense, and maritime issues. A distinguished graduate of the Naval Academy, he completed a 35-year career as a nuclear submariner in the US Navy. Admiral Mies has a wide range of operational command experience; he served as the senior operational commander of the US Submarine Force and he commanded U.S. Strategic Command for four years prior to retirement in 2002. He subsequently served as a Senior Vice President of Science Applications International Corporation, a provider of scientific and engineering applications for national security, energy, and environment, and as the President and Chief Executive Officer of Hicks and Associates, Inc, a subsidiary of SAIC from 2002-2007. Admiral Mies served as a director of Mutual of Omaha, an insurance and banking company, from 2002-2014, where he chaired the governance committee and served as a member of the audit, compensation, investment, and executive committees. From 2008–2010 Admiral Mies was a director of McDermott International, an engineering and construction company focused on energy infrastructure, where he served on the audit and governance committees. In 2010 he transitioned to the board of Babcock and Wilcox ("B&W") when that company spun off from McDermott International. He is chair of B&W's safety and security committee and a member of the governance committee. He is also a member of the Boards of Governors of Los Alamos and Lawrence Livermore National Security LLCs that operate their respective national laboratories. In addition to an undergraduate degree in mechanical engineering and mathematics, Admiral Mies completed post-graduate education at Oxford University, the Fletcher School of Law and Diplomacy, and Harvard University and holds a Masters degree in government administration and international relations. Admiral Mies makes a unique contribution to Exelon's generation oversight, finance and risk, and audit committees through his extensive leadership experience with nuclear power and strategic planning in the Navy and in business and through his experience on the boards of other companies.

**WILLIAM C. RICHARDSON, PH. D.**



**President and Chief Executive Officer Emeritus of the W.K. Kellogg Foundation**

**Age:** 74
**Director since:** 2005

**Committees:**
Lead Director
Member-Audit Committee
Member-Compensation and Leadership Development Committee
Member-Corporate Governance Committee
Member-Investment Oversight Committee (through January 28, 2014)

Dr. Richardson serves as lead director. Dr. Richardson is the President and Chief Executive Officer Emeritus of the W.K. Kellogg Foundation, a private foundation, and the President and Chief Executive Officer Emeritus of Johns Hopkins University. Dr. Richardson served as the President and CEO of the W. K. Kellogg Foundation until his retirement (1995-2005). He also served as chairman of the Kellogg Trust (1996-2007). In that position he and two other trustees directly oversaw the management of an approximately $7.7 billion fund, including a significant position in Kellogg Company (cereal and convenience foods). He was the President of Johns Hopkins University (1990-1995), and Executive Vice President and Provost of Pennsylvania State University (1984-1990). He is a member of the Institute of Medicine, National Academy of Sciences. Dr. Richardson has served as a director of The Bank of New York Mellon Corporation since 1998; of CSX Corporation (railroad) (1992-2008); and of Kellogg Company (1996-2007). Dr. Richardson serves on the audit and corporate governance and nominating committees of Bank of New York Mellon Corporation, and previously served on the audit, governance, and compensation committees of CSX. He was chair of the governance and compensation committees and lead director of CSX, and chair of the finance committee of Kellogg. Dr. Richardson has an MBA and PhD. from the University of Chicago Graduate School of Business. Dr. Richardson's experience as CEO of a large international research university and in leading a large investment fund and serving as a director of three major corporations and as a member of their governance, audit, risk and compensation committees make him qualified to serve as a director of Exelon. Through his experience, including experience on the committees of other organizations, Dr. Richardson contributes to the work of the Exelon audit, compensation and leadership development and corporate governance committees.

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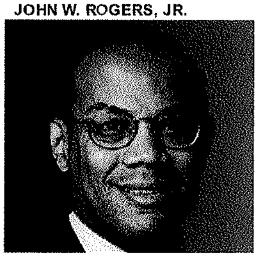
# Election of Directors

**JOHN W. ROGERS, JR.**



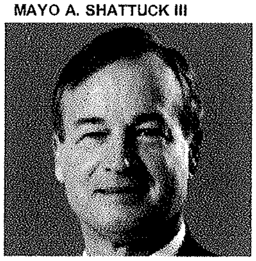
**Chairman and CEO of Ariel Investments, LLC**

**Age:** 56
**Director since:** 2000

**Committees:**
Chair-Investment Oversight Committee
Member-Corporate Governance Committee

Mr. Rogers is the founder, Chairman and CEO of Ariel Investments, LLC, an institutional money management firm with over $9 billion in assets under management, and serves as trustee of the Ariel Investment Trust. Since 2003, he has served as a director of McDonald's Corporation (global foodservice retailer) where he has served on the compensation, finance and corporate responsibility committees. Previously, he served as a director of Aon Corporation (risk management services, insurance and reinsurance brokerage and human capital and management consulting services) (1993-2012), where he served on the finance committee and as chair of the audit committee; GATX corporation (rail, marine and industrial equipment leasing) (1998-2004), where he served on the audit committee; Bank One Corporation (bank) (1998-2004), where he served on the audit and risk management and public responsibility committees; and Bally Total Fitness (fitness and health clubs) (2003-2006), where he served as the lead independent director and as chair of the compensation committee. Mr. Rogers' experience on the boards of a number of major corporations based in Chicago in a variety of industries has made him a leader in the Chicago business community with perspective into Chicago business developments. His role in Chicago's and the nation's African-American community brings diversity to the board and emphasis to Exelon's diversity initiatives and community outreach. His experience in investment management and financial markets and as a director of an insurance brokerage and services company are useful to Exelon, particularly with respect to risk management and the management of Exelon's extensive nuclear decommissioning and pension and post-retirement benefit trust funds, which are overseen by the investment oversight committee, which he chairs. Mr. Rogers' service on the boards and committees of other companies has given him experience that adds further depth to the Exelon corporate governance committee. He has spoken at and participated in a number of corporate governance conferences. He was named by the Outstanding Directors Exchange as one of six 2010 Outstanding Directors.

**MAYO A. SHATTUCK III**



**Former Chairman, President and Chief Executive Officer of Constellation Energy**

**Age:** 60
**Director since:** 2012

**Committees:**
Member-Generation Oversight Committee
Member-Investment Oversight Committee

Mr. Shattuck is Chairman of the Board of Exelon Corporation. Previously, Mr. Shattuck served as the Executive Chairman from March 2012 to February 2013. Prior to joining Exelon, Mr. Shattuck was the Chairman, President and Chief Executive Officer of Constellation Energy, a position he held from 2001 to March 2012. Mr. Shattuck was previously at Deutsche Bank, where he served as Chairman of the Board of Deutsche Bank Alex. Brown and, during his tenure, served as Global Head of Investment Banking and Global Head of Private Banking. From 1997 to 1999, he served as Vice Chairman of Bankers Trust Corporation, which merged with Deutsche Bank in June 1999. From 1991 until 1997, Mr. Shattuck was President and Chief Operating Officer and a Director of Alex. Brown Inc., which merged with Bankers Trust in September 1997. Mr. Shattuck is the past Chairman of the Board of the Institute of Nuclear Power Operations and was previously a member of the executive committee of the board of Edison Electric Institute. He was also Co-Chairman of the Center for Strategic & International Studies Commission on Nuclear Policy in the United States. He currently serves on the board of directors of Gap Inc. and is chairman of its audit and finance committee. He also serves as a director of Capital One Financial Corporation, where he is chairman of its compensation committee. Mr. Shattuck's qualifications to serve as director include his extensive experience in business and the energy industry in particular, gained from his service as Constellation Energy's Chief Executive Officer, which enables him to effectively identify strategic priorities and execute strategy. His financial expertise gained from his years of experience in the financial services industry also brings a valuable perspective to the board.

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# Election of Directors

**STEPHEN D. STEINOUR**

**Chairman, President and Chief Executive Officer of Huntington Bancshares Incorporated**

**Age:** 56
**Director since:** 2007

**Committees:**
Chair-Finance & Risk Committee
Member-Audit
Member-Compensation and Leadership Development Committee (through January 28, 2014)

In January 2009, Mr. Steinour was elected the Chairman, President and Chief Executive Officer of Huntington Bancshares Incorporated, a $64 billion regional bank holding company. Previously, he was the Chairman and Managing Partner of CrossHarbor Capital Partners, a private equity firm (2008-January 2009). From 2006 to 2008, he was President and CEO of Citizens Financial Group, Inc., a multistate commercial bank holding company. Prior to that, Mr. Steinour served as Vice Chairman and Chief Executive Officer of Citizens Mid-States regional banking (2005-2006). He served as Vice Chairman and Chief Executive Officer of Citizens Mid-Atlantic Region (2001-2005). At the beginning of his career, Mr. Steinour was an analyst for the U.S. Treasury Department and subsequently worked for the Federal Deposit Insurance Corporation. Mr. Steinour was a member of the board of trustees of the Liberty Property Trust (an office and industrial property real estate investment trust) from February 2010 until May 2014, where he served on its audit and compensation committees. Mr. Steinour was elected to the board of directors of L Brands (fashion retailer) in January 2014. He was elected to The Ohio State University Wexner Medical Center Board in November of 2013. Mr. Steinour is a member of council of The Pennsylvania Society, a non-profit, charitable organization which celebrates service to the Commonwealth of Pennsylvania. He also serves as a trustee of the Eisenhower Fellowships and is a member of the Columbus Partnership and a Trustee of the Columbus Downtown Development Corporation. He is a member of the American Bankers Association. Mr. Steinour also served as a member on the policy and legal affairs committees of the Pennsylvania Business Roundtable, an association of CEOs in large Pennsylvania companies representing significant employment and economic activity in the Commonwealth. He also has served on the board of and as the chairman of the Greater Philadelphia Chamber of Commerce. His experience at Citizens Bank gave him knowledge of the markets that Exelon Generation and PECO serve. His experience as a banker, with strong credit and risk management experience and knowledge of credit and capital markets, and his experience as Chairman and CEO of Huntington Bancshares enhances Mr. Steinour's value to the Exelon board and to the finance and risk and audit committees.

# Election of Directors

## DIRECTOR INDEPENDENCE

Under Exelon's Corporate Governance Principles, a substantial majority of the board must be composed of independent directors, as defined by the NYSE. In addition to complying with the NYSE rules, Exelon monitors the independence of audit and compensation and leadership development committee members under rules of the SEC (for members of the audit committee and compensation and leadership development committee) and the Internal Revenue Service (for members of the compensation and leadership development committee). The board has adopted independence criteria corresponding to the NYSE rules for director independence and the following categorical standards to address those relationships that are not specifically covered by the NYSE rules:

1. A director's relationship with another company with which Exelon does business will not be considered a material relationship that would impair the director's independence if the aggregate of payments made by Exelon to that other company, or received by Exelon from that other company, in the most recent fiscal year, is less than the greater of $1 million or 5% of the recipient's consolidated gross revenues in that year. In making this determination, a commercial transaction will not be deemed to affect a director's independence, if and to the extent that: (a) the transaction involves rates or charges that are determined by competitive bidding, set with reference to prevailing market prices set by a well-established commodity market, or fixed in conformity with law or governmental authority; or (b) the provider of goods or services in the transaction is determined by the purchaser to be the only practical source for the purchaser to obtain the goods or services.
2. If a director is a current employee, or a director's immediate family member is an executive officer, of a charitable or other tax-exempt organization to which Exelon has made contributions, the contributions will not be considered a material relationship that would impair the director's independence if the aggregate of contributions made by Exelon to that organization in its most recent fiscal year is less than the greater of $1 million or 2% of that organization's consolidated gross receipts in that year. In any other circumstance, a director's relationship with a charity or other tax-exempt organization to which Exelon makes contributions will not be considered a material relationship that would impair the director's independence if the aggregate of all contributions made by Exelon to that organization in its most recent fiscal year is less than the greater of $1 million or 5% of that organization's consolidated gross receipts in that year. Transactions and relationships with charitable and other tax-exempt organizations that exceed these standards will be evaluated by the board to determine whether there is any effect on a director's independence.

Each year, directors are requested to provide information about their business relationships with Exelon, including other boards on which they may serve, and their charitable, civic, cultural and professional affiliations. We also gather information on significant relationships between their immediate family members and Exelon. All relationships are evaluated by Exelon's Office of Corporate Governance for materiality. Data on transactions between Exelon and companies for which an Exelon director or an immediate family member serves as a director or executive officer are presented to the corporate governance committee, which reviews the data and makes recommendations to the full board regarding the materiality of such relationships for the purpose of assessing director independence. The same information is considered by the full board in making the final determination of independence.

Mr. Shattuck is not considered an independent director because of his employment as executive chairman of Exelon through February 2013. Mr. Crane is not considered an independent director because of his employment as president and chief executive officer of Exelon. Each of the other current Exelon directors was determined by our board of directors to be "independent" under applicable guidelines presented above. The amounts involved in the transactions between Exelon and its subsidiaries, on the one hand, and the companies with which a director or an immediate family member is associated, on the other hand, all fell below the thresholds specified by the NYSE rules and the categorical standards specified in the company's Corporate Governance Principles. Because Exelon provides utility services through its subsidiaries BGE, ComEd, PECO and Constellation and many of its directors live in areas served by the Exelon subsidiaries, many of the directors are affiliated with businesses and charities that receive utility services from Exelon's subsidiaries. The corporate governance committee does not review transactions pursuant to which Exelon sells gas or electricity to these businesses or charities at

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# Election of Directors

tariffed rates. Similarly, because Exelon and its subsidiaries are active in their communities and make substantial charitable contributions, and many of Exelon's directors live in communities served by Exelon and its subsidiaries and are active in those communities, many of Exelon's directors are affiliated with charities that receive contributions from Exelon and its subsidiaries. None of the directors or their immediate family members is an executive officer of any charitable organizations to which Exelon or its subsidiaries contribute. All such payments to charitable organizations were immaterial under the applicable independence criteria.

We describe below various transactions and relationships considered by the board in assessing the independence of Exelon directors.

**Ann C. Berzin**
Ms. Berzin serves as a director of a public company that provides equipment and services to Exelon Generation. In 2014, Exelon paid that company approximately $635,000.

**Nicholas DeBenedictis**
Mr. DeBenedictis serves as the chairman, president and chief executive officer of a public water utility company that received approximately $600,000 from Exelon for water supplies. Exelon made these purchases under tariffed utility rates. Mr. DeBenedictis serves as a director of a not-for-profit company that received $3,900,000 from Exelon for health care coverage for Exelon employees.

**Richard W. Mies**
Admiral Mies serves as the director of a public company that provides services to Exelon Generation. In 2014, Exelon paid that company approximately $6,800,000.

**Dr. William C. Richardson**
Dr. Richardson serves as a director of a public company that provided financial services to Exelon. In 2014, Exelon paid the company approximately $4,000,000.

**John W. Rogers, Jr.**
Mr. Rogers serves as a director of a company that is a customer of Exelon. The company paid Exelon approximately $19,000,000 in 2014.

**Stephen D. Steinour**
Mr. Steinour is the chairman, president and chief executive officer of a company that provided financial services to Exelon. In 2014, Exelon paid that company approximately $734,000. For additional information, see Related Person Transactions below.

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# Election of Directors

## RELATED PERSON TRANSACTIONS

Exelon has a written policy for the review and approval or the ratification of related person transactions. Transactions covered by the policy include commercial transactions for goods and services and the purchase of electricity or gas at non-tariffed rates from Exelon or any of its subsidiaries by an entity affiliated with a director or officer of Exelon. The retail purchase of electricity or gas from BGE, ComEd or PECO at rates set by tariff, and transactions between or among Exelon or its subsidiaries are not considered. Charitable contributions approved in accordance with Exelon's Charitable Contribution Guidelines are deemed approved or ratified under the Related Persons Transaction policy and do not require separate consideration and ratification.

As required by the policy, the board reviewed all commercial, charitable, civic and other relationships with Exelon in 2014 that were disclosed by directors and executive officers of Exelon, BGE, ComEd and PECO, and by executive officers of Exelon Generation that required separate consideration and ratification. The Office of Corporate Governance collected information about each of these transactions, including the related persons and entities involved and the dollar amounts either paid by or received by Exelon. The Office of Corporate Governance also conducted additional due diligence, where required to determine the specific circumstances of the particular transaction, including whether it was competitively bid or whether the consideration paid was based on tariffed rates.

The corporate governance committee and the board reviewed the analysis prepared by the Office of Corporate Governance, which identified those related person transactions which required ratification or approval, under the terms of the policy, or disclosure under the SEC regulations. The corporate governance committee and the board considered the facts and circumstances of each of these related person transactions, including the amounts involved, the nature of the director's or officer's relationship with the other party to the transaction, whether the transaction was competitively bid and whether the price was fixed or determined by a tariffed rate.

The committee recommended that the board ratify all of the transactions. On the basis of the committee's recommendation, the board did so. Several transactions were ratified because the related person served only as a director of the affiliated company, was not an officer or employee of the affiliated company and did not have a pecuniary or material interest in the transaction. For some of these transactions, the value or cost of the transaction was very small, and the board considered the de minimis nature of the transaction as further reason for ratifying it. The board approved and ratified other transactions that were the result of a competitive bidding process, and therefore were considered fairly priced, or arms length, regardless of any relationship. The remaining transactions were approved by the board, even though the director is an executive officer of the affiliated company, because the transactions involved only retail electricity or gas purchases under tariffed rates or the price and terms were determined as a result of a competitive bidding process. Only one of the related person transactions is required to be disclosed in this proxy statement.

Huntington Bank is a lender to Exelon and its subsidiaries and participates in their credit facilities. Huntington participates in the credit facilities on the same basis as other participating banks with terms based on a competitive process with a syndicate of banks. In 2014, Exelon and its subsidiaries paid Huntington Bank approximately $734,000 in fees for credit facilities and letters of credit. Mr. Steinour, an Exelon director, is also Chairman, President and Chief Executive Officer of Huntington Bancshares, the parent of Huntington Bank.

The corporate governance committee and the Exelon board reviewed Huntington Bank's participation in the credit facilities as related person transactions and concluded that the transactions were in the best interests of Exelon because Huntington participates in the credit facilities on terms equivalent to those of an unrelated bank. There is no indication that Mr. Steinour was involved in the negotiations of the credit facilities or had any direct or indirect material interest in the transactions or influence over them. As compared to Exelon's and Huntington's overall revenues, the transactions are immaterial, individually and in the aggregate.

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# Corporate Governance at Exelon

Exelon is committed to maintaining the highest standards of corporate governance. We believe that strong corporate governance is critical to achieving our performance goals and maintaining the trust and confidence of investors, employees, customers, regulatory agencies and other stakeholders.

## CORPORATE GOVERNANCE PRINCIPLES

Our Corporate Governance Principles, together with the board committee charters, provide the framework for the effective governance of Exelon. The board of directors has adopted our Corporate Governance Principles to address matters including qualifications for directors, standards of independence for directors, election of directors, responsibilities and expectations of directors, and evaluating board, committee and individual director performance. The Corporate Governance Principles also address director orientation and training, the evaluation of the chief executive officer and succession planning. The Corporate Governance Principles are revised from time to time to reflect emerging governance trends and to better address the particular needs of the company as they change over time.

## THE BOARD'S FUNCTION AND STRUCTURE

Exelon's business, property and affairs are managed under the direction of the board of directors. The board is elected by shareholders to oversee management of the company in the long-term interest of all shareholders. All directors stand for election annually and in uncontested elections must be elected by a majority of the votes cast. The board considers the interests of other constituencies, which include customers, employees, annuitants, suppliers, the communities we serve, and the environment. The board is committed to ensuring that Exelon conducts business in accordance with the highest standards of ethics, integrity, and transparency.

## BOARD LEADERSHIP

Exelon's Corporate Governance Principles establish the position of Lead Director. The Lead Director is an independent director elected by the independent directors of the Exelon board, upon the recommendation of the corporate governance committee, with responsibilities to act at any time when (1) the positions of chairman of the board and the chief executive officer are held by the same person; or (2) for other reasons the person holding the position of chairman of the board is not an independent director under the applicable director independence standards.

As specified in the Corporate Governance Principles, the role of the Lead Director includes:

- presiding at executive sessions of non-management or independent directors;
- calling meetings of the independent directors;
- serving as an advisor to the chairman and the chief executive officer ("CEO");
- functioning as the non-exclusive liaison between the non-management directors and the chairman and the CEO;
- adding items to agendas for board meetings;
- assuring the sufficiency of the time for discussion at board meetings;
- leading, in conjunction with the corporate governance and compensation and leadership development committees, the process for evaluating the performance of the chairman and the CEO and determining their respective compensation;
- leading on corporate governance initiatives relevant to board and committee operations;
- in the event of the death or incapacity of the chairman of the board, serving as the acting chairman of the board until such time as a chairman of the board is selected;

# Corporate Governance at Exelon

- receiving and responding to mail addressed to the board of directors; and
- having such additional powers and responsibilities as the board of directors may from time to time assign or request.

The Corporate Governance Principles grant the board of directors discretion to separate the roles of chairman and chief executive officer if the board determines that such a separation is in the best interests of Exelon and its shareholders. Upon the completion of the merger between Exelon and Constellation Energy Group in 2012, the board of directors separated the positions of chairman of the board and chief executive officer. The board appointed Mayo A. Shattuck III to the position of executive chairman and Christopher M. Crane to the position of chief executive officer. Mr. Shattuck served as executive chairman from March 2012 through February 2013 and he continues to serve as non-executive chairman of the Exelon board.

The board believes that Exelon has in place effective arrangements and structures to ensure that the company maintains the highest standard of corporate governance and board independence and independent board leadership and continued accountability of the chairman and the CEO to the board. These arrangements and structures include:

- 11 of the 13 nominees are independent and meet the independence requirements under the NYSE listing standards and the additional independence requirements under the company's Corporate Governance Principles.
- In 2012, the board elected William C. Richardson as the independent Lead Director. Dr. Richardson has been a member of our board since 2005. Dr. Richardson's responsibilities as Lead Director complement Mr. Shattuck's role as chairman and Mr. Crane's role as CEO while providing independent board leadership and the necessary checks and balances to hold the board, the chairman and the CEO accountable in their respective roles.
- The audit, compensation and leadership development, corporate governance and finance and risk committees are composed solely of and chaired by independent directors. The investment oversight and generation oversight committees are chaired by independent directors and, effective January 1, 2014, include Messrs. Crane and Shattuck as members of the committees.
- A significant portion of the business of the Exelon board is reviewed or approved by the board's committees, and the agendas of the board's committees are driven by the independent chairs through their discussions with management.
- The board agendas, in turn, are determined in large part by the committee agendas, and discussions at board meetings are driven to a significant degree by the committee agendas and the reports the committee chairs present to the full board.
- The performance and compensation of the CEO is reviewed annually by the full board in executive session under the leadership of the corporate governance and compensation and leadership development committees.

## BOARD OVERSIGHT OF RISK

The company operates in a market and regulatory environment that involves significant risks, many of which are beyond its control. The company has a risk management group consisting of a Chief Enterprise Risk Officer, a Chief Commercial Risk Officer, a Chief Credit Officer and a full-time staff of 133. The risk management group draws upon other company personnel for additional support on various matters related to the identification, assessment and management of enterprise risks. The company also has a Risk Management Committee comprising company officers who meet regularly to discuss matters related to enterprise risk management generally and particular risks associated with new developments or proposed transactions under consideration. Management of the company regularly meets with the Chief Enterprise Risk Officer and the Risk Management Committee to identify and evaluate the most significant risks of the businesses and appropriate steps to manage and mitigate those risks. In addition, the Chief Enterprise Risk Officer and the risk management group perform an annual assessment of enterprise risks, drawing upon resources throughout the company for an assessment of the probability and severity of the identified risks. The Chief Enterprise Risk Officer and senior executives of the company discuss those

# Corporate Governance at Exelon

risks with the board's finance and risk committee as well as the audit committee and, when appropriate, the BGE, ComEd and PECO boards of directors. In addition, the Exelon board's generation oversight committee evaluates risks related to the company's generation business. The committees of the Exelon board regularly report to the full board on the committees' discussions of enterprise risks. In addition, the Exelon board regularly discusses enterprise risks in connection with consideration of emerging trends or developments and in connection with the evaluation of capital investments and other business opportunities and business strategies.

## BOARD/COMMITTEE/DIRECTOR EVALUATION

The board has a three-part annual evaluation process that is coordinated by the Lead Director and the corporate governance committee: committee self-evaluations; a full board evaluation; and the evaluation of the individual directors. The committee self-evaluations consider whether and how well each committee has performed the responsibilities in its charter, whether the committee members possess the right skills and experience to perform their responsibilities or whether additional education or training is required, whether there are sufficient meetings covering the right topics, whether the meeting materials are effective, and other matters. The full board evaluation considers the following factors, among others, in light of the committee self-assessments: (1) the effectiveness of the board organization and committee structure; (2) the quality of meetings, agendas, presentations and meeting materials; (3) the effectiveness of director preparation and participation in discussions; (4) the effectiveness of director selection, orientation and continuing education processes; (5) the effectiveness of the process for establishing the CEO's performance criteria and evaluating his performance; and (6) the quality of administrative planning and logistical support.

Individual director performance assessments are conducted informally as needed and involve a discussion among the Lead Director and other directors, including members of the corporate governance committee, using the performance expectations for directors contained in the Corporate Governance Principles. In addition, the Lead Director, the chairman of the corporate governance committee or the chairman of the board provides individual feedback, as necessary.

## DIRECTOR EDUCATION

The board has a program for orienting new directors and providing continuing education for all directors that is overseen by the corporate governance committee. The orientation program is tailored to the needs of each new director depending on his or her level of experience serving on other boards and knowledge of the company or industry acquired before joining the board. New directors receive materials about Exelon, the board and board policies and operations and attend meetings with the CEO and executive vice presidents and members of their staff for a briefing on the executives' responsibilities, programs and challenges. New directors are also scheduled for tours of various company facilities, depending on their orientation needs (incumbent directors are also invited to participate in the site visits, if available).

Continuing director education is provided during portions of regular board and committee meetings and focuses on the topics necessary to enable the board to consider effectively issues before them at that time (such as new regulatory or accounting standards). The education often takes the form of "white papers," covering timely subjects or topics, which a director can review before the meeting and ask questions about during the meeting. The audit committee devotes a meeting each year to educating the committee members about new accounting rules and standards, and topics that are necessary to having a good understanding of our accounting practices and financial statements. The generation oversight committee uses site visits as a regular part of education for its members; the committee holds each meeting at a different generating station (nuclear, fossil or hydro) and the agenda always includes a briefing by local plant management, a tour of the facility and lunch with plant personnel. Continuing director education also involves individual directors' attendance at director education seminars. The company pays the cost for any director to attend outside director education seminars on corporate governance or other topics relevant to their service as directors.

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# Corporate Governance at Exelon

## INFORMATION ABOUT THE BOARD COMMITTEES

In determining the membership of the committees, the corporate governance committee has sought to have each committee reflect a range of backgrounds and experience and diversity. Every member of the audit committee qualifies as an "audit committee financial expert," as defined by SEC rules, and most of the members serve or have served on audit committees of other companies. The chairs of the audit and finance and risk committees sit on each other's committees, and there is significant overlap in the membership of the committees reflecting the overlap in responsibilities. Similarly, the chairs of the corporate governance and compensation and leadership development committees sit on each other's committees, which is helpful in the company's process for evaluating the performance and setting the compensation of the CEO. Almost all of the members of the corporate governance committee serve or have served on the corporate governance committees of other corporations. Several of the members of the compensation and leadership development committee have served on the compensation committees of other corporations. The investment oversight committee includes members with experience in investment banking and the economics of energy. The finance and risk committee includes members with experience in the economics of energy, nuclear operations, and banking and investment management, reflecting experience in dealing with the range of risks that the company faces.

In 2014, six standing committees assisted the board in carrying out its duties: the audit committee, the compensation and leadership development committee, the corporate governance committee, the finance and risk committee, the generation oversight committee and the investment oversight committee. The energy delivery oversight committee was terminated effective January 1, 2014. The chairman and the CEO are invited guests and are welcome to attend all committee meetings, except when the independent directors meet in executive session. The committees, their membership during 2014, changes in committee assignments in 2014, and their principal responsibilities are described below:

| Audit | Compensation and Leadership Development | Corporate Governance | Finance and Risk | Generation Oversight | Investment Oversight |
|---|---|---|---|---|---|
| Gin (Chair)[1] | Canning (Chair) | Lawless (Chair) | Steinour (Chair) | Mies (Chair) | Rogers (Chair) |
| Anderson (Chair)[2] | de Balmann | Canning | Anderson | Anderson | Crane |
| Berzin | Lawless | DeBenedictis | Berzin | Crane | Gin[1,3] |
| de Balmann | Richardson | Gin[1] | de Balmann | DeBenedictis | Joskow |
| Joskow | Steinour[3] | Mies[3] | DeBenedictis | Diaz[4] | Richardson[3] |
| Mies | | Richardson | Diaz[4] | Shattuck | Shattuck |
| Richardson | | Rogers | Gin[1] | | |
| Steinour | | | Joskow | | |
| | | | Mies | | |

Notes to Committee Membership Table:

1) Ms. Gin passed away on September 26, 2014.
2) Anthony K. Anderson became the Chair of the audit committee on October 21, 2014.
3) Member through January 28, 2014.
4) Hon. Nelson A. Diaz is not standing for reelection at the 2015 annual shareholders meeting.

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# Corporate Governance at Exelon

## AUDIT COMMITTEE

**Report of the Audit Committee**

The audit committee's primary responsibility is to assist the board of directors in fulfilling its responsibility to oversee and review the quality and integrity of the company's financial statements and internal controls over financial reporting, the independent auditor's qualifications and independence, and the performance of the company's internal audit function and of its independent auditor.

The audit committee is comprised entirely of independent directors and is governed by a board-approved, written charter stating its responsibilities. The charter is reviewed annually and updated, as appropriate, to address changes in regulatory requirements, authoritative guidance, evolving oversight practices and investor feedback. The audit committee charter was last amended on January 27, 2015, and is available on the Exelon website at www.exeloncorp.com on the corporate governance page under the Investors tab, and is available in print to any shareholder who requests a copy from Exelon's corporate secretary as described on page 90 of this proxy statement.

The audit committee satisfies the independence, financial experience and other qualification requirements of the New York Stock Exchange (NYSE) and applicable securities laws and regulations. The board of directors has determined that each of the members of the audit committee is an "audit committee financial expert" for purposes of the SEC's rules and also that each of the members of the audit committee is independent as defined by the rules of the NYSE and Exelon's Corporate Governance Principles.

Under its charter, the audit committee's principal duties include:

- Having sole authority to appoint, retain, or replace the independent auditor, subject to shareholder ratification, and to oversee the independence, compensation and performance of the independent auditor;
- Reviewing financial reporting and accounting policies and practices;
- Overseeing the work of the internal auditor and reviewing internal controls;
- With the assistance of the finance and risk committee, discussing guidelines and policies to govern the process of risk assessment and risk management; and
- Reviewing policies and procedures with respect to internal audits of officers' and directors' expenses, compliance with Exelon's Code of Business Conduct, and the receipt and treatment of complaints regarding accounting, internal controls or auditing matters.

The audit committee receives an annual report from the finance and risk committee of the board of directors regarding corporate risk management policy and other areas overseen by the finance and risk committee. Most members of the audit committee also serve on the finance and risk committee. On occasion, the audit and finance and risk committees meet jointly to review areas of mutual interest between the two committees.

The audit committee meets outside the presence of management for portions of its meetings to hold separate discussions with the independent auditor, the internal auditors, and the chief legal officer.

The audit committee met seven times in 2014, fulfilling its duties and responsibilities as outlined in its charter, as well as receiving periodic updates on the company's financial performance and strategic initiatives, as well as other matters germane to its responsibilities.

Management has primary responsibility for preparing the company's financial statements and establishing effective internal controls over financial reporting. PricewaterhouseCoopers LLP (PwC), the company's independent auditor, is responsible for auditing those financial statements and expressing an opinion on the conformity of the company's audited financial

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# Corporate Governance at Exelon

statements with generally accepted accounting principles and on the effectiveness of the company's internal controls over financial reporting based on criteria established in 2013 by the Committee of Sponsoring Organizations of the Treadway Commission.

In this context, the audit committee has reviewed and discussed with management and PwC the company's audited financial statements contained in the 2014 Annual Report on SEC Form 10-K, including the critical accounting policies applied by the company in the preparation of these financial statements. The audit committee discussed with PwC the matters required to be discussed by applicable requirements of the Public Company Accounting Oversight Board (PCAOB), and had the opportunity to ask PwC questions relating to such matters. These discussions included the quality, and not just the acceptability, of the accounting principles utilized, the reasonableness of significant accounting judgments, and the clarity of disclosures in the financial statements.

At each of its meetings in 2014, the audit committee met with the company's chief financial officer, corporate controller and other senior members of the company's financial management. The audit committee reviewed with PwC and the company's internal auditors the overall scope and plans for their respective audits in 2014. The audit committee also received regular updates from the company's internal auditors on internal controls and business risks and from the company's general counsel on compliance and ethics issues.

The audit committee met with the internal auditors and PwC, with and without management present, to discuss their evaluations of the company's internal controls and the overall quality of the company's financial reporting. The audit committee also met with the company's general counsel and deputy general counsel , with and without management present, to review and discuss compliance and ethics matters, including compliance with the company's Code of Business Conduct.

The audit committee annually considers the independence, qualifications, compensation and performance of PwC. Such consideration includes reviewing the written disclosures and the letter provided by PwC in accordance with applicable requirements of the PCAOB regarding PwC's communications with the audit committee concerning independence, and discussing with PwC their independence.

The audit committee is responsible for the approval of audit fees, and the committee reviewed and pre-approved all fees paid to PwC in 2014. The audit committee has adopted a policy for pre-approval of services to be performed by the independent auditor. Further information on this policy and on the fees paid to PwC in 2014 and 2013 can be found in the section of this proxy statement titled "Ratification of PriceWaterhouseCoopers LLP as Exelon's Independent Auditor for 2015." The audit committee periodically reviews the level of fees approved for payment to PwC and the pre-approved non-audit services PwC has provided to the company to ensure their compatibility with independence. The audit committee also monitors the company's hiring of former employees of PwC.

The audit committee monitors the performance of PwC's lead partner responsible for the audit, oversees the required rotation of PwC's lead audit partner and, through the audit committee chair, reviews and considers the selection of the lead audit partner. In addition, to help ensure auditor independence, the audit committee periodically considers whether there should be a rotation of the independent auditor.

PwC has served as the company's independent auditor since the company's formation in 2000. As in prior years, the audit committee and management have engaged in a review of PwC in connection with the audit committee's consideration of whether to recommend that shareholders ratify the selection of PwC as the company's independent auditor for 2015. In that review, the audit committee considered both the continued independence of PwC and whether retaining PwC is in the best interests of the company and its shareholders. In addition to independence, other factors considered by the audit committee included:

- PwC's historical and recent overall performance on the audit, including the quality of the audit committee's ongoing discussions with PwC;

# Corporate Governance at Exelon

- PwC's expertise and capability in handling the accounting, internal control, process and system risks and practices present in the company's energy generation and utility businesses, including relative to the corresponding expertise and capabilities of other audit firms;
- the quality, quantity and geographic location of PwC staff, and PwC's ability to provide responsive service;
- PwC's tenure as the company's independent auditor and its familiarity with the company's operations and businesses, accounting policies and practices and internal control over financial reporting;
- the significant time commitment required to onboard and educate a new audit firm that could distract management's focus on financial reporting and internal control;
- the appropriateness of PwC's fees, on both an absolute basis and as compared to services provided by other auditing firms to peer companies;
- an assessment of PwC's identification of its known significant legal risks and proceedings that may impair PwC's ability to perform the audit; and
- external information on audit quality and performance, including recent PCAOB reports on PwC and its peer firms.

The audit committee has concluded that PwC is independent from the company and its management, and has retained PwC as the company's independent auditor for 2015. The audit committee and the board believe that the continued retention of PwC is in the best interests of the company and its shareholders and have recommended that shareholders ratify the appointment of PwC as the company's independent auditor for 2015.

In addition, in reliance on the reviews and discussions referred to above, the Exelon audit committee recommended to the Exelon board of directors (and the Exelon board of directors approved) that the audited financial statements be included in Exelon Corporation's Annual Report on Form 10-K for the year ended December 31, 2014, for filing with the SEC.

February 9, 2015

THE AUDIT COMMITTEE
Anthony K. Anderson, Chair
Ann C. Berzin
Yves C. de Balmann
Paul L. Joskow
Richard W. Mies
William C. Richardson
Stephen D. Steinour

## COMPENSATION AND LEADERSHIP DEVELOPMENT COMMITTEE

The compensation and leadership development committee is composed entirely of independent directors and is governed by a board-approved charter stating its responsibilities. The committee met five times in 2014.

The compensation and leadership development committee's principal duties, as discussed in its charter, include:

- Ensuring that executive compensation levels and targets are aligned with, and designed to achieve, Exelon's strategic and operating objectives;
- Reviewing recommendations from management and outside consultants and approving or recommending approval of matters of executive compensation for officers of Exelon and its subsidiaries, including base salary, incentive awards, equity grants, perquisites, and other forms of compensation; and
- Reviewing and making recommendations to the board on leadership development, succession planning (other than the chairman and the chief executive officer and president) and diversity.

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# Corporate Governance at Exelon

Executive officers are involved in evaluation of the performance and development of initial recommendations with respect to compensation adjustments; however, the compensation and leadership development committee (and the independent directors with respect to the compensation of the CEO) makes the final determinations with respect to compensation programs and adjustments. The chairman and the CEO are considered invited guests and are welcome to attend the meetings of the compensation and leadership development committee, except when the committee meets in executive session to discuss, for example, the CEO's compensation. The chairman and the CEO cannot call meetings of the compensation and leadership development committee.

Management, including the executive officers, makes recommendations as to goals for the incentive compensation programs that are aligned with Exelon's business plan. The compensation and leadership development committee reviews the recommendations and establishes the final goals. The committee strives to ensure that the goals are consistent with the overall strategic goals set by the board of directors (including the individual goals of subsidiaries, as appropriate), that they are sufficiently difficult to meaningfully incent management performance, and, if the targets are met, that the payouts will be consistent with the design for the overall compensation program. Executive officers take an active role in evaluating the performance of the executives who report to them, directly or indirectly, and in recommending the amount of compensation their subordinate executives receive. Executive officers review peer group compensation data for each of their subordinates in conjunction with their annual performance reviews to formulate a recommendation for base salary and whether to apply an individual performance multiplier to the subordinate executive's incentive payouts, and if so, the amount of the multiplier.

Executive officers generally do not make recommendations with respect to annual and long-term incentive target percentages or payouts. The CEO reviews all of the recommendations of the executive officers before they are presented to the compensation and leadership development committee. The human resources function provides to the compensation and leadership development committee and the independent directors data showing the history of the compensation of the CEO and data that analyzes the cost of a range of several alternatives for changes to the compensation of the CEO, but the executive officers, the chairman and the CEO do not make any recommendation to the compensation and leadership development committee or the independent directors with respect to the compensation of the CEO.

The compensation and leadership development committee has delegated to the CEO the authority to make off-cycle equity awards to employees who are not subject to the limitations of Internal Revenue Code Section 162(m), are not executive officers for purposes of reporting under Section 16 of the Securities Exchange Act of 1934, and are not executive vice presidents or higher officers of Exelon, provided that such authority is limited to making grants of up to 600,000 shares in the aggregate, and 20,000 shares per recipient in any year. The compensation and leadership development committee reviews and ratifies these grants.

During fiscal 2014 and as of the date of this proxy statement, none of the members of the compensation and leadership development committee was or is an officer or employee of the company, and no executive officer of the company served or serves on any compensation committee or board of any company that employed or employs any members of the company's compensation and leadership development committee or board of directors.

**Compensation Consultant**

Pursuant to the compensation and leadership development committee's charter, the committee is authorized to retain and terminate, without board or management approval, the services of an independent compensation consultant to provide advice and assistance, as the committee deems appropriate. The committee has the sole authority to approve the consultant's fees and other retention terms, and reviews the independence of the consultant and any other services that the consultant or the consultant's firm may provide to the company. The chair of the compensation and leadership development committee reviews, negotiates and executes an engagement letter with the compensation consultant. The compensation consultant directly reports to the committee.

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# Corporate Governance at Exelon

The compensation and leadership development committee has engaged Semler Brossy Consulting Group, LLC and its Managing Principal Ms. Blair Jones as its consultant. The committee determined that Semler Brossy offered the strongest and most responsive team and would provide the most reliable and cost-competitive advice through experience, research and benchmarking. In reviewing the engagement in December 2014, the committee considered the following factors in determining that Ms. Jones and the firm are independent consultants and do not have any conflicts of interest:

- Semler Brossy performs no other services for the company or its affiliates and received no other fees from the company;
- the firm has formal written policies designed to prevent conflicts of interest; and
- there were no relationships of the firm and its consultants and Exelon and its officers, directors or affiliates except that Dr. Richardson had known another consultant from the firm in connection with his consulting for the compensation committee at another company where Dr. Richardson had previously served as a director.

As part of its ongoing services to the compensation and leadership development committee, the compensation consultant supports the committee in executing its duties and responsibilities with respect to Exelon's executive compensation programs by providing information regarding market trends and competitive compensation programs and strategies. In supporting the committee, the compensation consultant does the following:

- Prepares market data for each senior executive position, including evaluating Exelon's compensation strategy and reviewing and confirming the peer group used to prepare the market data;
- Provides the committee with an independent assessment of management recommendations for changes in the compensation structure;
- Works with management to ensure that the company's executive compensation programs are designed and administered consistent with the committee's requirements; and
- Provides ad hoc support to the committee, including discussing executive compensation and related corporate governance trends.

Exelon's human resources staff and senior management use the data provided by the compensation consultant to prepare documents for use by the compensation and leadership development committee in preparing their recommendations to the full board of directors or, in the case of the CEO, the independent directors, on compensation for the senior executives. In addition to its general responsibilities, the compensation consultant attends the compensation and leadership development committee's meetings, if requested. The committee, or Exelon's management on behalf of the committee, may also ask the compensation consultant to perform other executive and non-executive compensation-related projects. The committee has established a process for determining whether any significant additional services will be needed and whether a separate engagement for such services is necessary.

The committee has a formal compensation consultant independence policy that codifies its past practices. The compensation consultant independence policy is available on the Exelon website at www.exeloncorp.com, on the corporate governance page under the Investors tab. The purpose of the policy is to ensure that the advisers or consultants retained by the committee are independent of the company and its management, as determined by the committee using its reasonable business judgment. The committee considers all facts and circumstances it deems relevant, such as the nature of any relationship between a compensation consultant, the compensation consultant's firm, and the company and the nature of any services provided by the compensation consultant's firm to the company that are unrelated to the compensation consultant's work for the committee. Under the policy, a compensation consultant shall not be considered independent if the compensation consultant or the compensation consultant's firm receives more than one percent of its annual gross revenues for services provided to the company. Under the policy, the compensation consultant reports directly to the chair of the

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# Corporate Governance at Exelon

compensation and leadership development committee, and the committee approves the aggregate amount of fees to be paid to the compensation consultant or the compensation consultant's firm. The policy requires that the compensation consultant and any associates providing services to the compensation and leadership development committee have no direct involvement with any other aspects of the compensation consultant's firm's relationship with Exelon (other than any director compensation services that may be performed for the corporate governance committee), and that no element of the compensation consultant's compensation may be based on any consideration of the revenues for other services that the firm may provide to Exelon. For 2014, no fees were paid to Semler Brossy for additional services beyond its work as consultant to the compensation and leadership development committee.

## CORPORATE GOVERNANCE COMMITTEE

The corporate governance committee met five times in 2014. All members of the committee are independent directors.

In addition to its other duties described elsewhere in this proxy statement, the corporate governance committee's principal duties, as discussed in its charter, include:

- Reviewing and making recommendations on corporate, board and committee structure, organization, committee membership, functions, compensation and effectiveness;
- Monitoring corporate governance trends and making recommendations to the board regarding the Corporate Governance Principles;
- Identifying potential director candidates and coordinating the nominating process for directors;
- Coordinating the board's role in establishing performance criteria for the CEO and evaluating the performance of the CEO;
- Monitoring CEO succession planning;
- Overseeing Exelon's strategies and efforts to protect and improve the environment, including climate change, sustainability and the Exelon 2020 plan;
- Approving or amending delegations of authority for Exelon and its subsidiaries; and
- Overseeing Exelon's efforts to promote diversity among its contractors and suppliers.

The committee may act on behalf of the full board when the board is not in session. The committee utilizes an independent compensation consultant to assist it in evaluating directors' compensation, and for this purpose it periodically asks the consultant to prepare a study of the compensation of the company's directors compared to the directors of companies in the same peer group used for executive compensation. This study is used as the basis for the corporate governance committee's recommendations to the full board with respect to director compensation. The corporate governance committee may utilize other consultants, such as specialized search firms to identify candidates for director.

## FINANCE AND RISK COMMITTEE

The finance and risk committee met seven times in 2014.

The finance and risk committee's principal duties, as discussed in its current charter, include:

- Overseeing the company's risk management functions;
- Overseeing matters relating to the financial condition and risk exposures by Exelon;
- Monitoring the financial condition, capital structure, financing plans and programs, dividend policy, treasury policies and liquidity and related financial risk at Exelon and its major subsidiaries;

# Corporate Governance at Exelon

- Overseeing or appraising of the capital management and planning process, including capital investments, acquisitions and divestitures;
- Overseeing the company-wide risk management strategy, policies, procedures, and mitigation efforts, including insurance programs;
- Overseeing the strategy and performance of risk management policies relating to risks associated with marketing and trading of energy and energy-related products; and
- Reviewing and approving risk policies relating to power marketing, hedging and the use of derivatives.

Most members of the finance and risk committee also serve on the audit committee. On occasion, the finance and risk and audit committees meet jointly to review areas of mutual interest between the two committees.

## GENERATION OVERSIGHT COMMITTEE

The generation oversight committee met four times in 2014.

The generation oversight committee's principal duties, as discussed in its charter, include:

- Advising and assisting the full board in fulfilling its responsibilities to oversee the safe and reliable operation of all generating facilities owned or operated by Exelon or its subsidiaries, including those in which Exelon has significant equity or operational interests;
- Overseeing the management and operation of the company's generating facilities and the overall organizational effectiveness (both corporate and stations) of the generation operations;
- Overseeing the establishment of and compliance with policies and procedures to manage and mitigate risks associated with the security and integrity of Exelon Generation's assets; and
- Reviewing environmental, health and safety issues related to the company's generating facilities.

## INVESTMENT OVERSIGHT COMMITTEE

The investment oversight committee is responsible for general oversight of Exelon's investment management functions. The committee serves as a resource and advisory panel for Exelon's management-level investment management team and reports to the board.

The investment oversight committee met three times in 2014.

The investment oversight committee's principal duties, as discussed in its charter, include:

- Overseeing the management and investment of the assets held in trusts established or maintained by the company or any subsidiary for the purpose of funding the expense of decommissioning nuclear facilities;
- Monitoring the performance of the nuclear decommissioning trusts and the trustees, investment managers and other advisors and service providers for the trusts;
- Overseeing the evaluation, selection and retention of investment advisory and management, consulting, accounting, financial, clerical or other services with respect to the nuclear decommissioning trusts;
- Overseeing the evaluation, selection and appointment of trustees and other fiduciaries for the nuclear decommissioning trusts;

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# Corporate Governance at Exelon

- Overseeing the administration of the nuclear decommissioning trusts; and
- Monitoring and receiving periodic reports concerning the investment performance of the trusts under the pension and post-retirement welfare plans and the investment options under the savings plans.

## DIRECTOR NOMINATION PROCESS

The corporate governance committee serves as the nominating committee and recommends director nominees. The board of directors receives the proposed nominations from the corporate governance committee and approves the nominees to be included in the Exelon proxy materials that are distributed to shareholders.

The corporate governance committee considers all candidates for director, including directors currently serving on the board and candidates recommended by shareholders and others. The committee may also utilize specialized search firms to identify and assess potential candidates.

The committee determines the appropriate mix of skills and characteristics required to best fill the needs of the board and periodically reviews and updates the criteria as deemed necessary. The board believes that diversity in personal background, race, gender, age and nationality are important considerations in selecting candidates. All candidates are considered in light of the following standards and qualifications for director that are contained in the Exelon Corporate Governance Principles:

- Highest personal and professional ethics, integrity and values;
- An inquiring and independent mind;
- Practical wisdom and mature judgment;
- Broad training and experience at the policy-making level in business, government, education or technology;
- Expertise useful to Exelon and complementary to the background and experience of other Exelon board members;
- Willingness to devote the required amount of time to the duties and responsibilities of board membership;
- A commitment to serve over a period of years to develop knowledge about Exelon; and
- Involvement only in activities or interests that do not create a conflict with responsibilities to Exelon and its shareholders.

The satisfaction of these criteria is implemented and assessed through consideration of directors and nominees by the corporate governance committee and the board of directors and through the process for evaluation of the board's effectiveness. The corporate governance committee and the board believe that the criteria have been satisfied to create an effective mix of experience, skills, specialized knowledge, diversity, and other qualifications and attributes among members of the board of directors.

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# Corporate Governance at Exelon

## DIRECTOR RETIREMENT POLICY

For several years prior to 2010, the board had a retirement policy under which a director must retire at the end of the calendar year in which he or she reached the age of 72. In 2010, the corporate governance committee and the board re-evaluated the company's retirement policy and matters related to director succession. The board found that directors can normally continue to provide a valuable service to the company for several years beyond age 72. In addition, the board noted that under the retirement policy there were repeated instances where a number of director retirements would fall in the same year. For these reasons, the board was generally flexible in the application of the retirement policy and waived or suspended the policy when the purposes of the policy are outweighed by factors such as a desire for director continuity, the desire to retain the leadership or experience of a particular director, a need to identify equally qualified successors, a desire to avoid multiple retirements in one year, or other factors that mitigate against mandatory retirement. The board also recognized that, beginning with the annual meeting in 2010, shareholders are entitled to vote for the election of the entire board of directors. Accordingly, during 2010 the board amended the director retirement policy to provide that a director must retire at the end of the calendar year in which he or she reaches the age of 75.

## COMPENSATION OF NON-EMPLOYEE DIRECTORS

For their service as directors of the corporation in 2014, Exelon's non-employee directors received the compensation shown in the following table and explained in the accompanying notes. Mr. Crane, not shown in the table, received no additional compensation for his service as a member of the board of directors or its committees.

| | Fees Earned or Paid in Cash | | Stock Awards (see description below) | Change in Pension Value and Nonqualified Compensation Earnings (Note 1) | All Other Compensation (Note 2) | Total |
|---|---|---|---|---|---|---|
| | Annual Board & Committee Retainers | Board & Committee Meeting Fees | | | | |
| Anderson (3) | $ 93,913 | $ 60,000 | $ 100,000 | $ — | $ — | $ 253,913 |
| Berzin | 85,000 | 50,000 | 100,000 | — | 15,000 | 250,000 |
| Canning | 90,000 | 38,000 | 100,000 | — | 15,000 | 243,000 |
| de Balmann | 85,000 | 58,000 | 100,000 | — | — | 243,000 |
| DeBenedictis | 85,000 | 58,000 | 100,000 | — | 15,000 | 258,000 |
| Diaz | 85,000 | 48,000 | 100,000 | — | 5,000 | 238,000 |
| Gin (4) | 77,609 | 40,000 | 73,901 | — | — | 191,510 |
| Joskow | 85,000 | 56,000 | 100,000 | — | — | 241,000 |
| Lawless (5) | 90,000 | 36,000 | 100,000 | — | — | 226,000 |
| Mies | 110,000 | 64,000 | 100,000 | — | 15,000 | 289,000 |
| Richardson (5) | 110,000 | 56,000 | 100,000 | — | 15,000 | 281,000 |
| Rogers | 90,000 | 36,000 | 100,000 | — | 15,000 | 241,000 |
| Shattuck (6) | 426,806 | 33,000 | 100,000 | — | 15,000 | 574,806 |
| Steinour | 95,000 | 50,000 | 100,000 | — | 15,000 | 260,000 |
| Total All Directors | 1,608,328 | 683,000 | 1,373,901 | 0 | 125,000 | 3,790,229 |

Notes:

(1) Values in this column represent that portion of the directors' accrued earnings in their non-qualified deferred compensation account that were considered as above market. See the description below under the heading "Deferred Compensation." For 2014, none of the directors recognized any such earnings.

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# Corporate Governance at Exelon

(2) Values in this column represent the company's matching portion of the director's contribution to qualified educational institutions pursuant to Exelon's matching gift plan described below in Other Compensation.
(3) Mr. Anderson was appointed chair of the audit committee effective October 21, 2014 and his chairman's retainer is prorated from October 20, 2014 when he served as acting chair.
(4) Ms. Gin passed away on September 26, 2014. All retainers were prorated through that date.
(5) In addition to the amounts shown in the table, Mr. Lawless and Dr. Richardson, who also served as directors of the Exelon Foundation during 2014, received $4,000 and $6,000 respectively from the Foundation for attending meetings of the Foundation's board. Exelon contributes to the Foundation to pay for the Foundation's operating expenses.
(6) Compensation for Mr. Shattuck includes a portion of cash retainers earned in 2013 but not paid until January 2014.

**Fees Earned or Paid in Cash**
In 2014, all directors received an annual retainer of $80,000 paid in cash. The Lead Director received an additional annual retainer of $25,000. The non-executive chairman of the board received an annual retainer at the rate of $300,000 per year in in addition to board and selected committee meeting fees. Committee chairs receive an additional $10,000 retainer per year. In recognition of the additional time commitment and responsibility, members of the audit committee and generation oversight committee, including the committee chairs, receive an additional $5,000 per year for their participation on these committees, and the chairs of these committees receive a $20,000 annual retainer.

Directors receive $2,000 for each meeting of the board that they attend, whether in person or by means of teleconferencing or video conferencing equipment. Directors serving on board committees receive $2,000 for each meeting they attend; directors serving on the generation oversight committee receive $3,000 for each meeting of that committee they attend due to the additional travel that is required and the length of those meetings. Directors also receive a $2,000 meeting fee for attending the annual shareholders meeting and the annual strategy retreat.

**Stock Awards**
Rather than paying directors entirely in cash, Exelon pays a significant portion of director compensation in the form of deferred stock units. Directors receive deferred stock units worth $100,000 per year. Deferred stock units are granted and credited to a notional account maintained on the books of the corporation at the end of each calendar quarter based upon the closing price of Exelon common stock on the day the quarterly dividend is paid. Deferred stock units earn the same dividends available to all holders of Exelon common stock, which are reinvested in the account as additional stock units. The deferred stock units are not paid out to the directors until they retire from the board, leaving these amounts at risk during the director's entire tenure on the board.

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# Corporate Governance at Exelon

As of December 31, 2014, the directors held the following amounts of deferred Exelon common stock units. The units are valued at the closing price of Exelon common stock on December 31, 2014, which was $37.08. Legacy plans include those stock units earned from Exelon's predecessor and merged companies, PECO Energy Company, Unicom Corporation and Constellation Energy Group, Inc. For Mr. Rogers, the legacy deferred stock units reflect accrued benefits from the Unicom 1996 Directors Fee Plan, which was terminated in 2000; for Ms. Berzin, Mr. de Balmann and Mr. Lawless the legacy units reflect accrued benefits from the Constellation Energy Group, Inc. Deferred Compensation Plan for Non-employee Directors that was terminated on March 12, 2012.

| | Year First Elected to the Board | Deferred Stock Units From Legacy Plans # | Deferred Stock Units From Exelon Plan # | Total Deferred Stock Units # | Fair Market Value as of 12/31/14 $ |
|---|---|---|---|---|---|
| Anthony K. Anderson | 2013 | | 6,164 | 6,164 | $228.561 |
| Ann C. Berzin | 2012 | 24,961 | 9,047 | 34,008 | 1,261,017 |
| John A. Canning | 2008 | | 18,965 | 18,965 | 703,222 |
| Yves C. de Balmann | 2012 | 34,468 | 9,047 | 43,515 | 1,613,536 |
| Nicholas DeBenedictis | 2002 | | 26,687 | 26,687 | 989,554 |
| Nelson A. Diaz | 2004 | | 26,530 | 26,530 | 983,732 |
| Paul L. Joskow | 2007 | | 20,476 | 20,476 | 759,250 |
| Robert J. Lawless | 2012 | 38,244 | 9,047 | 47,291 | 1,753,550 |
| Richard W. Mies | 2009 | | 17,757 | 17,757 | 658,430 |
| William C. Richardson | 2005 | | 24,299 | 24,299 | 901,007 |
| John W. Rogers, Jr | 1999 | 4,571 | 36,000 | 40,571 | 1,504,373 |
| Mayo A. Shattuck III | 2012 | | 5,906 | 5,906 | 218,994 |
| Stephen D. Steinour | 2007 | | 20,818 | 20,818 | 771,931 |
| **Total All Directors** | | **102,244** | **230,743** | **332,987** | **12,347,157** |

**Deferred Compensation**

Directors may elect to defer any portion their cash compensation in a non-qualified multi-fund deferred compensation plan. Each director has an unfunded account where the dollar balance can be invested in one or more of several mutual funds, including one fund composed entirely of Exelon common stock. Fund balances (including those amounts invested in the Exelon common stock fund) will be settled in cash and may be distributed in a lump sum or in annual installment payments upon a director's reaching age 65, age 72 or upon retirement from the board. These funds are identical to those that are available to those available to company employees who participate in the Exelon Employee Savings Plan.

**Other Compensation**

Exelon has a board expense reimbursement policy under which directors are reimbursed for reasonable travel to and from their primary or secondary residence and lodging expenses incurred when attending board and committee meetings or other events on behalf of Exelon (including director's orientation or continuing education programs, facility visits or other business

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# Corporate Governance at Exelon

related activities for the benefit of Exelon). Under the policy, Exelon will arrange for its corporate aircraft to transport groups of directors, or when necessary, individual directors, to meetings in order to maximize the time available for meetings and discussion. Directors may bring their spouses or guests on Exelon's corporate aircraft when they are invited to an Exelon event, and the value of this travel, calculated according to IRS regulations, is imputed to the director as additional taxable income.

Exelon pays the cost of a director's spouse's travel, meals, lodging and related activities when the spouses are invited to attend company or industry related events where it is customary and expected that directors attend with their spouses. The cost of such travel, meals and other activities is imputed to the director as additional taxable income. However, in most cases there is no incremental cost to Exelon of providing transportation and lodging for a director's spouse when he or she accompanies the director, and the only additional costs to Exelon are those for meals and activities and to reimburse the director for the taxes on the imputed income. In 2014, no incremental cost to the company to provide these perquisites and there was no amounts paid for the reimbursement of taxes on imputed income.

Exelon has a matching gift program available to directors, officers and employees that matches their contributions to eligible not-for-profit organizations up to $15,000 per year for directors; $10,000 per year for executives ($15,000 per year through the end of 2013 for legacy Constellation Energy Group executives) and up to $5,000 per year for other employees.

**Compensation Philosophy**
The Exelon board has a policy of targeting their compensation to the median board compensation of the same peer group of companies used to benchmark executive compensation. The base compensation (cash and stock retainers for board service and meeting fees) paid to Exelon directors in 2013 remained unchanged since 2008. In 2013, the corporate governance committee asked Semler Brossy Consulting Group, the independent consultant to the compensation and leadership development committee, to perform a director compensation study. The study found that in 2013 and some earlier years, compensation paid to Exelon directors was below the median of the peer group and below the median resulting from several published studies of larger groups. In January 2014, the board increased the annual cash retainer for board service from $50,000 to $80,000 but left all other compensation unchanged. The increase represented a 1.6 percent annual increase in basic director compensation over the five year period since 2008.

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# Ownership of Exelon Stock

## STOCK OWNERSHIP REQUIREMENTS FOR DIRECTORS AND OFFICERS

Under Exelon's Corporate Governance Principles, all directors are required to own, within five years after election to the board, at least 15,000 shares of Exelon common stock or deferred stock units or shares accrued in the Exelon common stock fund of the directors' deferred compensation plan. The board amended the corporate governance principles in July 2013 to increase the ownership requirement from 5,000 shares to 15,000 shares. The corporate governance committee utilized an independent compensation consultant who determined that, compared to its peer group, Exelon's ownership requirement is reasonable.

To strengthen the alignment of executives' interests with those of shareholders, the compensation and leadership development committee establishes stock ownership requirements for officers of the company. Officers, other than the CEO, are required to own, within the later of five years after their employment or September 30, 2012, stock having a market value (based on the 60-day average stock price as of September 30, 2012) equal to or greater than multiples of their base salary or fixed numbers of shares as shown in the table below. The CEO is required to own six times his base salary. The compensation and leadership development committee has determined that stock options are not considered for purposes of satisfying this requirement. Performance shares that have been earned but not vested, unvested restricted shares, restricted stock units, and shares held in the Exelon Stock Deferral Plan will count toward the stock ownership requirement, as will certificates and dividend reinvestment plans; shares held in 401(k) Employee Savings Plans; shares held by spouses or children; broker accounts held in street name; and IRAs and trust accounts in which the executive is a beneficiary. These guidelines may be equitably adjusted in the case of promotions in the discretion of the Senior Vice President and Chief Human Resources Officer.

| Officer | Number of Exelon Shares |
|---|---|
| Chief Executive Officer | 6 x annual salary divided by 60-day average share price |
| Exelon executive vice presidents and above | 3 x annual salary divided by 60-day average share price |
| Presidents of subsidiary companies | 2 x annual salary divided by 60-day average share price |
| Senior vice presidents | The lesser of 17,500 shares or 2 x annual salary divided by 60-day average share price |
| Vice presidents and other executives | The lesser of 6,500 shares or 1 x annual salary divided by 60-day average share price |

The following table shows the status of each currently-employed NEO against the new ownership targets as of January 31, 2015.

| Name | Stock Ownership Target (Shares) [A] | Total Shares and Share Equivalents Held as of January 31, 2015 [B] | Stock Ownership Percentage [B]/[A] |
|---|---|---|---|
| **Crane** | 188,062 | 378,203 | 201% |
| **Thayer** | 53,148 | 122,963 | 231% |
| **Cornew** | 57,236 | 143,325 | 250% |
| **Von Hoene** | 57,236 | 139,419 | 244% |
| **O'Brien** | 59,280 | 129,025 | 218% |

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# Ownership of Exelon Stock

## BENEFICIAL OWNERSHIP TABLE

The following table shows the ownership of Exelon common stock as of January 31, 2015 by each director, each named executive officer in the Summary Compensation Table, and for all directors and executive officers as a group.

| | [A] | [B] | [C] | [D]=[A]+[B]+[C] | [E] | [F]=[D]+[E] |
|---|---|---|---|---|---|---|
| Directors (Note 3) | Beneficially Owned Shares | Shares Held in Company Plans (Note 1) | Vested Stock Options and Options that Vest Within 60 days | Total Shares Held | Share Equivalents to be Settled in Cash or Stock (Note 2) | Total Share Interest |
| Anthony K. Anderson | 0 | 6,164 | 0 | 6,164 | 0 | 6,164 |
| Ann C. Berzin | 0 | 34,008 | 0 | 34,008 | 7,978 | 41,986 |
| John A. Canning, Jr. | 5,000 | 18,965 | 0 | 23,965 | 1,106 | 25,071 |
| Yves, C. de Balmann | 1,910 | 43,515 | 0 | 45,425 | 0 | 45,425 |
| Nicholas DeBenedictis | 5,000 | 26,687 | 0 | 31,687 | 0 | 31,687 |
| Nelson A. Diaz | 1,500 | 26,530 | 0 | 28,030 | 5,480 | 33,510 |
| Paul L. Joskow | 2,000 | 20,476 | 0 | 22,476 | 6,035 | 28,511 |
| Robert J. Lawless | 3,273 | 47,291 | 0 | 50,564 | 7,106 | 57,670 |
| Richard W. Mies | 0 | 17,757 | 0 | 17,757 | 0 | 17,757 |
| William C. Richardson | 1,715 | 24,299 | 0 | 26,014 | 0 | 26,014 |
| John W. Rogers, Jr. | 11,374 | 40,571 | 0 | 51,945 | 13,756 | 65,701 |
| Mayo A. Shattuck III | 491,358 | 5,906 | 3,266,335 | 3,763,599 | 0 | 3,763,599 |
| Stephen D. Steinour | 4,887 | 20,818 | 0 | 25,705 | 25,210 | 50,915 |
| Christopher M. Crane | 176,668 | 195,762 | 495,250 | 867,680 | 5,773 | 873,453 |
| Jonathan W. Thayer | 33,703 | 89,260 | 572,955 | 695,918 | 0 | 695,918 |
| Kenneth W. Cornew | 42,988 | 98,799 | 132,575 | 274,362 | 1,538 | 275,900 |
| William A. Von Hoene, Jr. | 71,773 | 64,641 | 246,200 | 382,614 | 3,005 | 385,619 |
| Denis P. O'Brien | 65,324 | 58,156 | 244,200 | 367,680 | 5,545 | 373,225 |
| **Total** | | | | | | |
| Directors & Executive Officers as a group (23 people) See Note 3 | 1,027,338 | 942,517 | 5,176,215 | 7,146,070 | 82,532 | 7,228,602 |

(1) *The shares listed under Shares Held in Company Plans, Column [B], include restricted shares, shares held in the 401(k) plan, and deferred shares held in the Stock Deferral Plan.*

(2) *The shares listed above under Share Equivalents to be Settled in Cash, Column [E], include unvested performance shares that may be settled in cash or stock depending on where the named officer stands with respect to the stock ownership requirement, and phantom shares held in a non-qualified deferred compensation plan which will be settled in cash on a 1 for 1 basis upon retirement or termination.*

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# Ownership of Exelon Stock

(3) *Beneficial ownership, shown in Column [A], of directors and executive officers as a group represents less than 1% of the outstanding shares of Exelon common stock. Total includes share holdings from all directors and NEOs as well as those executive officers listed in Item 1, Executive Officers of the Registrants in Exelon's 2014 Annual Report on Form 10-K filed on February 13, 2015, who are not NEOs for purposes of compensation disclosure.*

## OTHER SIGNIFICANT OWNERS OF EXELON STOCK

Shown in the table below are those owners who are known to Exelon to hold more than 5% of the outstanding common stock. This information is based on the most recent Schedule 13Gs filed with the SEC by Capital Research Global Investors on February 13, 2015, State Street Corporation on February 12, 2015, BlackRock, Inc. on February 9, 2015, The Vanguard Group on February 11, 2015 and Franklin Resources, Inc. on February 9, 2015.

| Name and address of beneficial owner | Amount and nature of beneficial ownership | Percent of class |
|---|---|---|
| Capital Research Global Investors (1)<br>333 South Hope Street<br>Los Angeles, CA 90071 | 69,797,514 | 8.1% |
| State Street Corporation (2)<br>State Street Financial Center<br>One Lincoln Street<br>Boston, MA 02111 | 51,650,257 | 6.0% |
| BlackRock, Inc. (3)<br>40 East 52nd Street<br>New York, NY 10022 | 51,360,702 | 6.0% |
| The Vanguard Group (4)<br>100 Vanguard Blvd.<br>Malvern, PA 19355 | 50,125,938 | 5.83% |
| Franklin Resources, Inc. and certain related entities (5)<br>One Franklin Parkway<br>San Mateo, CA 94403 | 45,614,955 | 5.3% |

(1) *Capital Research Global Investors disclosed in its Schedule 13G/A that it has sole voting and dispositive power over 69,797,514 shares.*

(2) *State Street Corporation disclosed in its Schedule 13G that it has shared voting and dispositive power over 51,650,257 shares.*

(3) *BlackRock, Inc. disclosed in its Schedule 13G/A that it has sole power to vote or to direct the vote of 44,148,730 shares and sole power to dispose or direct the disposition of 51,360,702 shares.*

(4) *The Vanguard Group disclosed in its Schedule 13G/A that it has sole power to vote or direct the vote of 1,469,150 shares and sole power to dispose or direct the disposition of 48,713,728 shares.*

(5) *Franklin Resources, Inc., Charles B. Johnson, Rupert H. Johnson, Jr., and Franklin Advisers, Inc. Schedule 13G filing, dated February 9, 2015, reports beneficial ownership collectively of 45,614,955 shares, with sole voting power as to 45,254,730 shares and sole dispositive power as to 45,589,730 shares in Franklin Advisers, Inc., and sole voting power and sole dispositive power as to 14,000 shares in Franklin Advisory Services, LLC, 10,800 shares as to Franklin Templeton Institutional, LLC, and 425 shares as to Fiduciary Trust Company International.*

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# Ownership of Exelon Stock

## 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 | 31,538,000 | $36.67 | 32,278,000 |

(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 and 2014, 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 7,138,000 shares. At target, the number of securities to be issued for such awards is 3,753,000. The deferred stock units granted to directors includes 284,000 shares to be issued upon the conversion of deferred stock units awarded to members of the Exelon board of directors, and 98,000 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—Common Stock of the Combined Notes to Consolidated Financial Statements included in Exelon's 2014 Annual Report on Form 10-K 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 $46.81.*

(3) *Includes 23,460,000 shares available for issuance from the company's employee stock purchase plan.*

## SECTION 16(a) BENEFICIAL OWNERSHIP REPORTING COMPLIANCE

Based upon signed affirmations received from directors and officers, as well as administrative review of company plans and accounts administered by private brokers on behalf of directors and officers which have been disclosed to Exelon by the individual directors and officers, Exelon believes that its directors and officers made all required filings on a timely basis during 2014.

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# Exelon's Independent Auditor for 2015

## PROPOSAL 2: THE RATIFICATION OF PRICEWATERHOUSECOOPERS LLP AS EXELON'S INDEPENDENT AUDITOR FOR 2015

The audit committee and the board of directors have concluded that retaining PricewaterhouseCoopers LLP (PwC) is in the best interests of the company and its shareholders based on consideration of the factors set forth in the Report of the Audit Committee on pages 16-18 of this proxy statement. Representatives of PwC will attend the annual meeting to answer appropriate questions, and may make a statement if they desire.

The Exelon audit committee policy for pre-approval of audit and non-audit services to be performed by the independent auditor is available on the Exelon website at www.exeloncorp.com on the corporate governance page under the Investors tab. Under this policy the audit committee pre-approves all audit and non-audit services to be provided by the independent auditor, taking into account the nature, scope and projected fees of each service as well any potential implications on auditor independence. The policy specifically sets forth services the independent auditor is prohibited from performing by applicable law or regulation. Further, the audit committee may determine to prohibit other services that in its view may compromise, or appear to compromise, the independence and objectivity of the independent auditor. Predictable and recurring audit and permitted non-audit services are considered for pre-approval by the audit committee on an annual basis. For any services not covered by these initial pre-approvals, the audit committee has delegated authority to the committee's chair to pre-approve any audit or permitted non-audit service with fees in amounts less than $500,000. Services with fees exceeding $500,000 require full committee pre-approval. The audit committee receives quarterly reports on the actual services provided by and fees incurred with the independent auditor. None of the services provided by the independent auditor was provided pursuant to the de minimis exception to the pre-approval requirements contained in the SEC's rules.

The following table presents fees for professional audit services rendered by PricewaterhouseCoopers for the audit of Exelon's annual financial statements for the years ended December 31, 2014 and 2013, and fees billed for other services rendered by PricewaterhouseCoopers during those periods.

| | Year Ended December 31, | |
|---|---|---|
| (in thousands) | 2014 | 2013 |
| Audit fees [(a)] | $17,751 | $18,136 |
| Audit related fees [(b)] | 1,607 | 1,817 |
| Tax fees [(c)] | 1,562 | 1,000 |
| All other fees [(d)] | 37 | 24 |

(a) *Audit fees include financial statement audits and reviews under statutory or regulatory requirements and services that generally only the auditor reasonably can provide, including issuance of comfort letters and consents for debt and equity issuances and other attest services required by statute or regulation.*

(b) *Audit related fees consist of assurance and related services that are traditionally performed by the auditor such as accounting assistance and due diligence in connection with proposed acquisitions or sales, consultations concerning financial accounting and reporting standards and audits of stand-alone financial statements or other assurance services not required by statute or regulation.*

(c) *Tax fees consist of tax compliance, tax planning and tax advice and consulting services, including assistance and representation in connection with tax audits and appeals, tax advice related to proposed acquisitions or sales, employee benefit plans and requests for rulings or technical advice from taxing authorities.*

(d) *All other fees primarily reflect accounting research software license costs.*

**The board of directors unanimously recommends a vote "FOR" the ratification of PricewaterhouseCoopers LLP as Exelon's Independent Auditor for 2015.**

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# Advisory Vote on Executive Compensation

## PROPOSAL 3: ADVISORY VOTE ON EXECUTIVE COMPENSATION

We are providing shareholders with an annual advisory (non-binding) vote on the compensation paid to the company's named executive officers, as disclosed in this proxy statement on pages 35-76, in accordance with the compensation disclosure rules of the SEC. Accordingly, you may vote on the following resolution at the 2015 annual meeting.

> RESOLVED, that the company's shareholders approve, on an advisory basis, the compensation of the named executive officers, as disclosed in the company's proxy statement for the 2015 Annual Meeting of Shareholders pursuant to the rules of the SEC, including the Compensation Discussion and Analysis, the 2014 Summary Compensation Table and the other related tables and disclosure.

The board of directors recommends a vote FOR this proposal because it believes:

- The company's compensation framework is effective in achieving its goals of providing market competitive pay that fosters the attraction, motivation and retention of key talent;
- A majority of compensation is performance-based and contingent on achieving financial and operational results that align the interests of executives with those of the company's shareholders; and
- The compensation framework is consistent with best practices that drive outstanding company performance while creating long-term shareholder value.

While this advisory proposal, commonly referred to as "say-on-pay," is not binding, the board of directors and the compensation and leadership development committee will review and consider the voting results when annually evaluating our executive compensation program. To facilitate more frequent shareholder input, the board adopted a policy of providing for annual say-on-pay advisory votes.

> When casting your 2015 say on pay vote, we encourage you to consider the company's 2014 performance, which included total shareholder return of 40.6%, operating earnings per share that were in-line with full year guidance, and outstanding operational performance. The committee and board believe that the changes to the compensation program we made in 2013, largely based on shareholder feedback and alignment with market practice, strengthened the connection of pay with performance. The committee and the board appreciate your feedback and have implemented some enhancements to the 2015 executive compensation program based on shareholder engagement during the past year. We continue to look forward to hearing from shareholders about potential future program enhancements.

**The board of directors unanimously recommends a vote "FOR" approval of the compensation paid to the company's named executives, as disclosed in this proxy statement.**

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# Report of the Compensation and Leadership Development Committee

*"Exelon's executive compensation framework is designed to pay for performance and align the interests of executives, shareholders and other key stakeholders."*

*The Compensation & Leadership Development Committee*

The committee is composed solely of independent directors, and we are accountable for ensuring that the decisions we make about executive compensation are in the best interests of shareholders. We accomplish this objective by having a robust compensation framework that emphasizes pay-for-performance, resulting in a majority of pay being at risk and contingent on the achievement of financial and operational goals. In fact, 90% of Exelon's CEO compensation is at risk, which is higher than our peer group average and strongly aligns with shareholder interests. Our goals under the annual incentive program and the long-term incentive program's performance share program are aligned to metrics that correlate directly to driving long-term shareholder value creation and are developed with significant stretch and rigor.

The committee proactively seeks shareholder feedback as part of its year-round engagement program, which includes reaching out to our top shareholders to listen to feedback regarding our executive compensation program, disclosure practices and corporate governance. The committee values our shareholders' insights and considers their feedback in addition to other factors such as emerging market practices, when formulating our executive compensation programs and making pay decisions. A full description of our shareholder outreach efforts and the changes we have made based on your feedback is detailed under "Shareholder Engagement" on pages 41-42.

Our strategy continues to leverage our integrated business model to create value by using our strong balance sheet to invest in both regulated and competitive businesses to drive growth. Part of the board's overarching strategy is to manage for the future and to make decisions that are in the best long-term interests of Exelon's shareholders, as well as ensure strong annual financial and operational performance.

The compensation and leadership development committee has reviewed and discussed the Compensation Discussion and Analysis required by Item 402(b) of Regulation S-K with management and, based on such review and discussion, the committee recommended to the board that the Compensation Discussion and Analysis be included in the 2015 Proxy Statement.

February 27, 2015

THE COMPENSATION & LEADERSHIP DEVELOPMENT COMMITTEE
John A. Canning, Jr., Chair
Yves C. de Balmann
Robert J. Lawless
William C. Richardson

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# Compensation Discussion & Analysis



## *Section I: Overview*

**Company Strategy**
Exelon's strategy is to ***leverage our integrated business model to create value and diversify our business***. Each of our businesses – regulated utilities and competitive generation and energy sales – features a mix of attributes that, when combined, offers our shareholders and customers a unique value proposition:

- Our utilities (BGE, ComEd, and PECO) provide a foundation for stable earnings and dividend support, while
- Our competitive businesses in Exelon Generation and Constellation provide commodity exposure to power and gas price upside and a platform to diversify into adjacent markets, while providing residual dividend support.

The board of directors believes our strategy provides a platform for optimal success in an industry experiencing fundamental and sweeping change, such as tightening conventional baseload generation, emergence of the intelligent electric network (i.e., Smart Meters/Smart Grid), and changing consumer behaviors that are pushing toward a decentralized system. While enhancing Exelon's core value, it enables us to take advantage of multiple opportunities, rather than relying on any one segment of our industry's value chain.

*Executive Compensation Goals are aligned with the Company's Strategy:* In designing the company's executive compensation programs, the committee strives to align the goals and underlying metrics with the company's strategy, while including compensation risk mitigating design features to discourage our executives and employees from taking excessive risks for short-term benefits that may harm the company and our shareholders. We believe consistent execution of our strategy over multi-year periods will lead to an increase in our stock price.

For the company's Annual Incentive Program ("AIP"), all named executive officers ("NEOs"), with the exception of the CEO of Exelon Utilities, are tied 100% to adjusted non-GAAP operating earnings per share ("EPS"), directly correlating to bottom-line financial results that drive shareholder value creation. For the Long-Term Incentive ("LTI") Program, our NEOs receive both Performance Share Units ("PSUs") and Restricted Stock Units ("RSUs"). The PSUs are contingent on achieving a threshold level of performance over a three-year period based on two goals, financial management and operational excellence, that are aligned with driving long-term shareholder value creation. A full scorecard for the 2014 PSU goals, underlying metrics and performance can be found on page 53.

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# Compensation Discussion & Analysis

## Key Take-Aways for 2014 Compensation

### 1 STRONG COMPANY PERFORMANCE

- Exelon's share price was up 35.4% for the year, with a total shareholder return of 40.6% (including reinvested dividends), outpacing the S&P 500 (14.0%) and our 20 company peer group (23.3%).
- Exelon Utilities completed the year with high performance across key operating areas including safety (top decile) and top quartile performance in all three utilities (BGE, ComEd and PECO) for both outage frequency and duration. See chart on page 53 for full details.
- Exelon Generation had exceptional plant performance in 2014, including nuclear capacity factor of over 94%, power dispatch match of nearly 97%, and renewables (wind and solar) energy capture of 95%.

### 2 STRONG EXECUTION OF M&A STRATEGY

- Executed a merger agreement to acquire Pepco Holdings Inc. (PHI) for $6.8 billion, with an anticipated closing in the second or third quarter of 2015.
- Divested five non-core power plants to yield $1.8 billion of pre-tax proceeds ($1.4 billion after-tax).
- Acquired two Midwest energy marketers (ProLiance and Integrys), virtually doubling the number of customers by adding over 1.2 million residential and commercial and industrial customers.
- Invested in a portfolio of Bloom Energy fuel cell products to further the Bloom partnership and advance Exelon's objectives in building its distributed generation business.

### 3 DECREASE IN CEO REPORTED COMPENSATION

- As reported in the summary compensation table on page 60, CEO pay decreased 13%, or 20% excluding the change in pension value and deferred compensation earnings. This decrease was attributed to the one-time, performance-based transition award. For more details refer to the transition award section on page 53.
- For 2014, CEO target total direct compensation was calibrated to approximate the market median of the 20 company peer group. For additional information, please see CEO pay-at-glance section on pages 39-41.

### 4 COMMITMENT TO SHAREHOLDER ENGAGEMENT

- The company met with investors holding approximately 46% of the outstanding shares (up from about 35% the prior year).
- No material plan design changes made for 2014, as shareholders expressed support for the design changes that we implemented in 2013. See page 41 for details.
- For 2015, the company is making a few enhancements based on shareholder feedback received during the fall 2014 outreach, including increasing the CEO's stock ownership target from 5X to 6X to align more closely with market practice.

### 5 STRONG INCENTIVE GOAL RIGOR

- The 2014 performance share goals, which are part of the LTI Program, were set at a level that resulted in eight of the ten underlying metrics being more challenging than the prior year, aligning with top quartile and top decile industry performance standards as shown on page 53.

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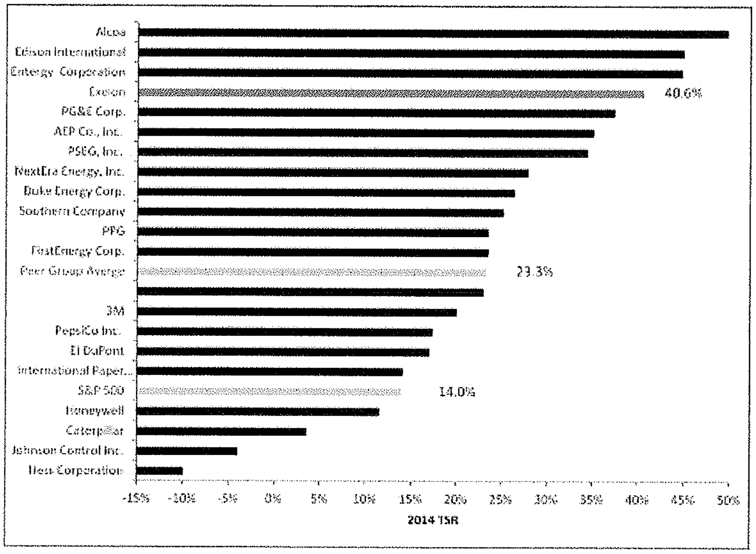
# Compensation Discussion & Analysis

## Strategic Business Results

*Strong Absolute and Relative 2014 Total Shareholder Return Performance:* After lagging stock performance in prior years, Exelon performed very well in 2014 under Mr. Crane's leadership, with its stock price leading the way (see Exelon's 2014 total shareholder return relative to its 20 company peer group in the chart below). This outperformance reflects a slight improvement in natural gas forward prices in 2014, coupled with above target financial, operational and cost management performance. Our 2014 compensation decisions reflect the company's overall performance.




*Strong Opportunistic Growth Execution:* Exelon has been taking steps to expand its regulated business operations as part of its efforts to achieve earnings and cash flow stability. In 2014, Exelon announced its intent to acquire PHI, which will help the company leverage scale and maintain cost discipline, while strengthening and expanding its regulated assets. The transaction will shift our earnings mix to be substantially more regulated with 61-67% of earnings coming from the regulated side in the 2016-2017 period. As we have communicated publicly, this transaction is expected to close in the second or third quarter of 2015 and to add $0.15 – $0.20 to earnings per share in 2017.

The company took the initiative in 2014 by investing in and growing its existing business lines: utilities, competitive energy sales, and generation. Exelon has been optimizing its power generation fleet by selling select unregulated assets to assist in funding the pending PHI acquisition. Exelon has also been diversifying into promising markets and technologies through the acquisition of a company that sells liquid natural gas, the acquisitions of two energy marketers (ProLiance and Integrys), resulting in 1.2 million new customers to Constellation's business, and developing two combined-cycle gas turbines (CCGT) in Texas (which will add over 2,100+ MWs). The CCGTs are scheduled to come online by the summer of 2017, and will help the company expand its clean energy portfolio consistent with EPA regulations. The CCGTs will be cash flow and EPS accretive relative to the coal plants that the company sold in 2014. The company sold five unregulated coal and gas plants in 2014 for $1.8 billion of pre-tax proceeds ($1.4 billion after-tax).

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# Compensation Discussion & Analysis

*Major Regulatory Developments in 2014:* There were a number of major regulatory developments in 2014 that affected both our utilities and the generation business.

- For the utilities, Exelon had two positive outcomes for ComEd and BGE rate cases, with ComEd receiving 95% of its ask for the third consecutive case and BGE receiving its first settlement since 1999. These outcomes highlight our continued commitment to the customers we serve in each region.
- On the generation side, the company has seen progress in the Illinois nuclear discussions, with four reports released which highlight the reliability, economic and environmental benefits of nuclear plants to the state. Additionally, PJM's Capacity Performance Proposal has been submitted to FERC, and the company supports steps being taken to ensure reliability in the region.

## Executive Compensation Framework and Central Themes

The goal of our executive compensation program is to retain and reward leaders who create long-term value for our shareholders by delivering on objectives set forth in the company's long-term strategic plan. This goal affects the compensation elements we use and drives our compensation decisions. The primary compensation elements are depicted in the table below, with all except for base salary being "pay-at-risk" and linked to changes in the stock price and achievement of short-term and long-term company financial and operational goals that build shareholder value.

| Pay Element | SALARY | Annual Incentive Plan | Performance Share Units | Restricted Stock Units |
|---|---|---|---|---|
| WHO RECEIVES | All named executive officers → | | | |
| Pay-At-Risk | Fixed | Variable → | | |
| WHEN GRANTED | Bi-weekly with annual review | Annually in January for prior year | Annually in January | Annually in January |
| TYPE OF PERFORMANCE | Short-term emphasis → | | Long-term emphasis → | |
| PERFORMANCE PERIOD | Ongoing | 1 year | 3 years | Vest one-third per year over 3 years |
| HOW PAYOUT DETERMINED | Market assessment, individual performance and internal equity | Corporate / Business Unit performance, and individual performance | Average performance on company performance measures, relative TSR modifier and individual performance | Market assessment, individual performance and internal equity |
| MOST RECENT PERFORMANCE MEASURES | Individual performance relative to objectives | Operating EPS | Financial management goals (60%), operational excellence goals (40%), and relative three-year TSR modifier | Individual performance and potential |
| PURPOSE | Provide income certainty so that executives can focus on achieving key business priorities and objectives | Holds executives accountable for performance against near-term business objectives | Aligns the interest of executives with shareholders by providing awards contingent on achieving pre-established three-year financial and operational goals | Enhances the retention of key talent and provides an ongoing alignment of executive interests with those of shareholders |

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# Compensation Discussion & Analysis

### *Executive Compensation Principles*

The following principles help guide and inform the committee in delivering highly effective executive compensation programs that drive pay for performance, mitigate risk, and foster the attraction, motivation and retention of top leadership talent in order to enable the company to execute against its strategic business plan and ultimately deliver long-term shareholder value.

**We Manage for the Long-term**
The board manages for the long-term and makes pay decisions that are in the best long-term interests of the company and shareholders.

**Competitiveness**
Our NEOs' pay levels are set by taking into consideration multiple factors, including peer group market data, internal equity comparisons, experience, performance and retention.

**Strong Compensation Framework**
We have a strong compensation framework that is market-based and drives pay for performance and alignment with shareholders based on having a majority of NEO pay at risk in the form of annual incentives and stock awards.

**Robust Stock Ownership Guidelines**
Executives are required to meet and maintain significant stock ownership requirements. For 2014, our CEO's requirement was 5X base salary (*6X starting in 2015*), while other NEOs were 3X.

**Strong Shareholder Engagement**
We engage directly with shareholders and take actions to improve our compensation programs based on year-round feedback from shareholders.

**Balance**
Since we manage for the long-term, we believe pay at risk should reward the appropriate balance of short- and long-term financial and strategic business results.

### CEO Pay at-a-Glance

*2014 Target Total Direct Compensation (TDC):* In determining target TDC for the CEO, the independent directors considered his individual performance and assessed market competitiveness before it set Mr. Crane's 2014 target TDC at $12.05 million (up 3.8% from the prior year). In setting his pay, there was no change in base salary and the board ensured the vast majority (90%) of pay is at risk, including almost 78% of his pay in the form of Long-Term Incentives (LTI), which is almost eight percentage points higher than the average CEO in our 20 company peer group.

Mr. Crane's TDC comprises the following:

- Base salary of $1.2 million (unchanged from 2013)
- Annual Incentive target opportunity of $1.5 million or 125% of base salary (unchanged from 2013)
- Long-Term Incentive target opportunity of $9.3 million, with 67% delivered in performance share units and 33% as RSUs.

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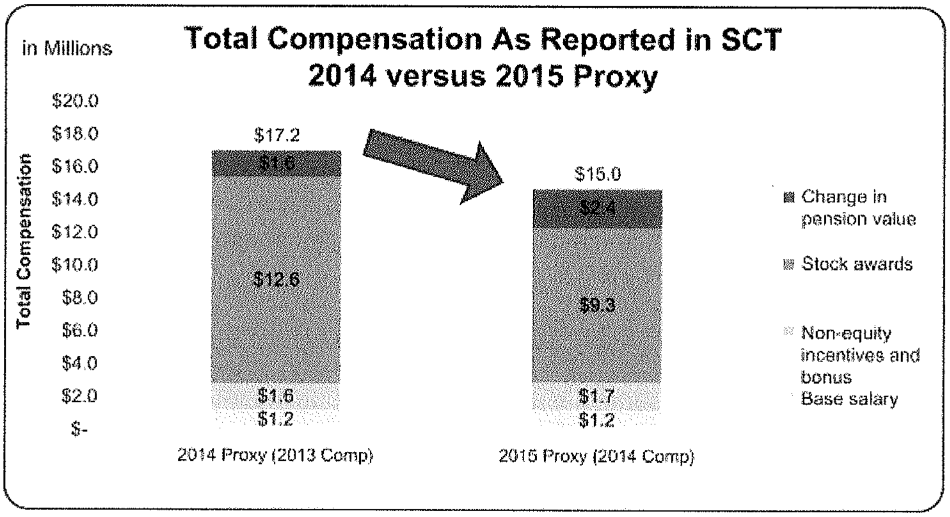
# Compensation Discussion & Analysis

*Decrease in Reported Pay:* Mr. Crane's pay as reported in the Summary Compensation Table decreased this year by 13%, or 20% *excluding* the change in pension value and deferred compensation. His compensation declined in 2014 because in 2013 it included a one-time performance-based transition award valued at about $3.7 million, that was fully disclosed in last year's proxy statement (see page 53 for more information). This was partially offset by this year's increase in the change in pension value of approximately $0.9 million, resulting from the change in interest rates and new mortality tables for 2014. Mr. Crane's take-home (W-2) pay remains a small portion of the reported pay (i.e., about 45% in 2014).




*2014 CEO Payouts:*

For Mr. Crane, the board awarded a 2014 AIP payout of $1,708,905 based on operating EPS performance of $2.39 (103.57% of target), multiplied by an individual performance modifier ("IPM") of 110%. The committee utilized an IPM to recognize Mr. Crane's outstanding execution against the company's strategic business plan, while delivering strong stock price, financial, operational, and regulatory advocacy performance. Key highlights are depicted below, which also apply to the other NEOs.

- Total shareholder return of + 40.6%, outperforming the S&P 500 by almost 27 percentage points,
- Strong operational performance across the Utilities (top decile safety and outage frequency) and Generation (nuclear capacity factor of over 94% and Exelon Power gas and hydro dispatch match of 96.5%),
- Numerous corporate transactions, including executing a merger agreement to acquire PHI ($6.8 billion), divesting five non-core power plants to yield $1.8 billion of pre-tax proceeds ($1.4 billion after-tax), and acquiring two energy marketers (Proliance and Integrys), resulting in 1.2 million new customers for Constellation's business, and
- Both BGE and ComEd had very strong distribution rate case outcomes in 2014. BGE reached a unanimous settlement in its 2014 rate case, the first time this has occurred since 1999. ComEd was successful in that the Illinois Commerce Commission granted a revenue requirement increase of $232 million, or 95% of what the utility requested.

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# Compensation Discussion & Analysis

The board also approved the final portion of the performance-based transition award, equating to 91,378 shares, valued at $3,412,055 based on the closing stock price of $37.34 on January 26, 2015. This payout was calculated based on the average of performance share goal results for 2013 (125.00% after the committee exercised negative discretion to reduce from actual performance of 147.8% of target) and 2014 (105.56%). The one-time transition award was granted in 2013 to address the lengthening of the performance period from one year to three years.

## Shareholder Engagement

*2014 Advisory Vote on Executive Compensation.* Shareholders approved our advisory vote on executive compensation with 69% of the votes cast FOR the compensation of our NEOs, which was below our desired achievement level. Based on our conversations with shareholders, the lower vote in favor of executive compensation was primarily a result of:

- Negative 2013 total shareholder return (-3.5%), and
- A significant increase in 2013 reported compensation from the prior year, which was driven by the confluence of (a) increasing the CEO's pay from 20% below market median to the market median, and (b) the requirement to report the full value of the one-time performance-based transition award, even though the performance had not yet been measured.

*We actively engage with our shareholders throughout the year.* Since 2006, we have maintained a shareholder engagement program in which we proactively reach out to our top shareholders and leading proxy advisory services firms with the objective of educating them about the corporate governance and executive compensation changes we have implemented as well as seeking feedback on other potential executive compensation and corporate governance matters. Our engagement team consists of leaders from human resources, investor relations and the office of corporate governance. Additionally, our committee chair participated on some of the calls in 2013 and 2014.

*Robust 2014 Shareholder Outreach.* In the spring of 2014, we spoke with our top shareholders and sought input from others. These calls, which included the holders of about 35% of our outstanding common shares, were highly valued as we were able to discuss the 2014 proxy statement and key executive compensation and corporate governance matters contained within the document as well as review executive compensation changes that were based on prior shareholder input and implemented in 2013 and are reflected in the 2014 proxy statement. We also structured a similar outreach in the fall that included the chairman of the committee participating in select telephonic meetings with top investors and proxy advisory services firms. We spoke with investors who hold almost 46% of the common shares outstanding.

*Positive shareholder feedback received on:*

- **Pay-for-performance alignment:** Projected 2014 CEO pay as reported in the Summary Compensation Table will decrease, and total shareholder return will be up significantly,
- **Strong stock ownership achievement levels:** Each NEO owns at least 200% of his stock ownership target,
- **Pay-at-risk:** CEO's pay-at-risk is 90% (with 78% in the form of LTI),
- **LTI mix:** 67% performance share units and 33% restricted stock units for NEOs,
- **Goal rigor:** Eight of the ten performance share program metrics were more challenging for 2014 as compared to 2013, and
- **Quality of disclosure:** Robust and comprehensive executive compensation disclosures highlighted, simplified and summarized relevant information through the use of graphics and an executive summary.

In addition, shareholders reaffirmed their support for the executive compensation program changes that we implemented in 2013, when we:

- Lengthened the performance period for the performance share program from one to three years,

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# Compensation Discussion & Analysis

- Reinstated total shareholder return as a modifier under our performance share program,
- Reduced the number of goals in our performance share program from six to two,
- Changed the goals under the performance share program from qualitative to quantitative, and
- Eliminated stock options and changed the mix of equity for NEOs to 67% performance share units and 33% restricted stock units.

Our 2014 executive compensation program was largely unchanged from 2013 as the committee believes the program is aligned strongly with shareholder interests and market practice. Even though the committee believes the program is meeting its objectives in rewarding financial, operational, and strategic success, it is always seeking ways to improve the executive compensation program and disclosure. During 2014, the company received suggestions relating to emerging trends in executive compensation practices and our disclosures about our program. In addition, the committee and management reviewed correspondence submitted by individual and institutional shareholders, analyzed market practices at peer companies and sought advice from the committee's independent compensation consultant. Based on shareholder discussions and recommendations, the committee, during its annual evaluation of the company's executive compensation programs and evolving market practices, made changes to our programs and disclosures:

| 2014 Shareholder Feedback | Exelon Actions as a result of 2014 Shareholder Feedback |
|---|---|
| ***Disclose Full Performance Share Unit Performance Scale*** | **Added the threshold and distinguished performance levels to the performance share plan disclosure (see page 53)** |
| ***Describe How Metrics Link to Strategy*** | **Expanded disclosure to include how metrics tie to the business and link back to strategy** |
| ***Enhance Alignment with Shareholder Interests*** | **Increased the stock ownership guidelines for the CEO from 5X base salary to 6X base salary, starting in 2015** |
| ***Disclose Executive Stock Ownership*** | **Added an achievement level table for each NEO** |
| ***Clarify the Long-Term Incentive Plan*** | **Amended the plan expressly prohibiting the buyout of stock options; repricing of stock options was already prohibited** |
| ***Consider Change to Peer Group for Market Assessment*** | **Modified the peer group for the 2015 market assessment to remove PepsiCo Inc. which was larger than the company's criteria of 0.5X to 2.0X for both revenue and market capitalization** |

### *Section II: How We Design Our Executive Compensation Programs to Pay for Performance*

Our approach to compensating our NEOs is to align the long-term interests of Exelon's executives with those of our shareholders. Our compensation framework is based on providing market-competitive programs that attract and retain top talent necessary to effectively lead a company with the scale and technical complexity of Exelon throughout all phases of the business cycle. The framework is also designed so that a majority of our pay is at risk and directly linked to Exelon's shareholder returns and to other performance factors that measure our progress against the financial management and operational excellence goals in our strategic and operating plans to promote pay for performance. This means when excellent performance is achieved, pay will be above target. Failure to achieve objectives will result in below-market pay.

In order to reaffirm the link between pay and performance, the committee annually reviews the executive compensation components, targets and payouts and approves compensation for all NEOs except the CEO, whose compensation is approved by the independent directors on the recommendation of the committee and its independent consultant (Semler

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# Compensation Discussion & Analysis

Brossy Consulting Group). The committee evaluates goals under the annual and long-term incentive programs to ensure that they are challenging, contain appropriate stretch, and are designed to mitigate excessive risk. Goals are selected and evaluated based on support for Exelon's long-term business plan.

## 2014 NEO Pay Decisions

As stated in its charter, one of the committee's most important responsibilities is to recommend the CEO's compensation to the independent directors. The committee fulfills its oversight responsibilities and provides thoughtful recommendations by analyzing peer group compensation data with its independent compensation consultant and company performance data. The committee reviews the various elements of the CEO's compensation in the context of the target total direct compensation (base salary, annual and long-term incentive target opportunities) and then presents its recommendations following the compensation governance process set forth below.

| Roles of board, Compensation and Leadership Development Committee, and CEO | Steps | When |
|---|---|---|
| • CEO compensation decisions are made by the independent members of the board, based on recommendation of the compensation and leadership development committee. | **Design Compensation Program** – 2014 incentive programs are discussed, including AIP and LTI designs. | December 2, 2013 |
| • Other NEO compensation decisions are made by the committee, based on a number of factors including input from the CEO and the independent compensation consultant. | **Establish Range of Compensation Opportunities** – AIP and LTI opportunities are set with appropriate stretch (threshold, target, and distinguished performance levels). Individual AIP and LTI opportunities are established, as well as any base salary adjustment. | January 27, 2014 |
| • The committee is advised by an independent compensation consultant. | **Review Performance** – Performance is reviewed, which leads to payout decisions (e.g., AIP, and the second installment of the transition award). | January 26, 2015 |

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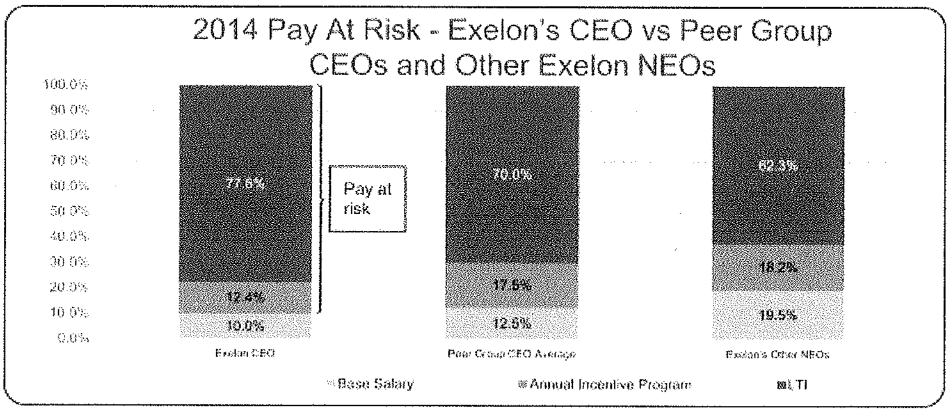
# Compensation Discussion & Analysis

## How Pay-for-Performance Works

*Overview.* Exelon has a long-standing commitment to link pay and performance by providing a majority of compensation that is tied to stock price or contingent on achieving short and long-term objectives.

- **Program Design:** Over 80% of NEO pay at Exelon is variable as depicted in the chart below, which directly ties pay to the company's performance, including financial results, operational goals, and stock performance relative to our peer group.
- **Performance Assessment:** The committee uses a comprehensive and well-defined process to assess performance, which encompasses both short and long-term financial and operational results relative to our goals. The committee ensures that the goal-setting process is rigorous and contains appropriate stretch for both internal measures and operational metrics that generally set achieving industry first quartile performance as the target. For more information, refer to the 2014 performance share scorecard on page 53.



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# Compensation Discussion & Analysis

## What We Do and Don't Do

Exelon's executive compensation philosophy focuses on pay-for-performance and reflects appropriate governance practices aligned with the needs of our business. Below is a summary of our executive compensation practices that are aligned with best practice, as well as a list of those practices we avoid because they do not align with shareholders' long-term interests.

**What We Do**

- ✓ Pay-for-performance – 90% of CEO pay (and almost 81% for other NEOs) is at risk in the form of AIP and LTI
- ✓ Stock ownership – 6X base salary for CEO (starting in 2015) and 3X for other NEOs
- ✓ Mitigation of undue risk in executive compensation programs
- ✓ Double-trigger change-in-control benefits – requires change-in-control plus involuntary termination
- ✓ Independent compensation consultant – works directly with the committee
- ✓ We annually evaluate management succession and leadership development efforts
- ✓ We provide limited, modest perquisites based on sound business rationale
- ✓ We proactively seek investor feedback on executive compensation programs
- ✓ We prohibit hedging transactions, short sales, derivative transactions or pledging of company stock
- ✓ We require executive officers and directors to trade through 10b5-1 trading plans or obtain pre-approval before trading Exelon stock
- ✓ We annually assess our programs against peer companies and best practices
- ✓ Incentive targets contain appropriate stretch based on industry performance and/or Exelon's business plan
- ✓ We clawback incentive compensation paid to an executive who has engaged in fraud or intentional misconduct

**What We Don't Do**

- × No guaranteed minimum payout of AIP or LTI programs
- × No employment agreements
- × No dividend-equivalents on unearned performance share units
- × No excise tax gross-ups for change-in-control agreements entered into after April 2009
- × No inclusion of the value of LTI awards in pension or severance calculations
- × No additional credited service under supplemental pension plans since 2004
- × No option re-pricing

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# Compensation Discussion & Analysis

## Assessing Executive Compensation Programs

*Overview.* An assessment of our executives' compensation levels against our peer group is one of several considerations in the pay setting process. Peer group practices are analyzed each year for target total direct compensation and for other pay practices, such as perquisites and the mix of LTI vehicles. Because Exelon is one of the largest energy services companies, we compare executive compensation against a blended peer group with which we compete for talent. The peer group includes 10 energy services companies and 10 high-performing asset intensive general industry companies (with an emphasis when appropriate on companies that are subject to effects of commodity prices such as Exelon) with comparable annual sales (.5x to 2x) and market capitalizations generally above $10 billion. Each year the compensation and leadership development committee, working with its independent consultant, reviews the composition of the peer group and determines whether any changes should be made. The peer group for 2014 was the same as 2013, with the exception of PPG Industries replacing Murphy Oil after it spun off part of its business. Exelon's 2014 peer group consists of the following 20 companies:

| General Industry | | Energy Services | |
|---|---|---|---|
| 3M | Honeywell | AEP Co., Inc. | FirstEnergy Corp. |
| Alcoa | International Paper Co. | Dominion Resources, Inc. | NextEra Energy, Inc. |
| Caterpillar | Johnson Controls Inc. | Duke Energy Corp. | PG&E Corp. |
| El DuPont | PepsiCo Inc. | Edison International | PSEG, Inc. |
| Hess Corporation | PPG Industries | Entergy Corporation | Southern Company |

For 2015, the committee approved a change to the peer group to remove PepsiCo Inc., which was larger than the company's criteria of 0.5X to 2.0X for both revenue and market capitalization. Additionally, Caterpillar and PPG Industries did not participate in the TowersWatson executive survey. As a result, the committee approved replacing these three companies with Deere & Company, General Dynamics and Northrup Grumman.

*Comparing Exelon to its Peer Group.* The median revenue of our peer group for the year ended December 31, 2014 was approximately $21.7 billion as compared to our revenues of $27.4 billion. As of December 31, 2014, the median market capitalization of our peer group was $32.0 billion as compared to our market capitalization of $31.9 billion.

*Setting Target TDC for our NEOs.* The committee initially sets target TDC at market median of peer group companies, but can vary based on competencies and skills, scope of responsibilities, the executive's experience and performance, retention, succession planning and the organizational structure of the businesses (internal alignment and reporting relationships). In establishing NEO compensation levels, the committee does not formally consider the ratio of individual NEO compensation relative to other NEOs.

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# Compensation Discussion & Analysis

## *Section III: What We Pay and Why We Pay it*

Our NEOs for 2014 are unchanged from 2013 as shown below:

| Name | Title |
|---|---|
| Christopher M. Crane | President and Chief Executive Officer, Exelon |
| Jonathan W. Thayer | Senior EVP and Chief Financial Officer, Exelon |
| Kenneth W. Cornew | Senior EVP and Chief Commercial Officer, Exelon; President and Chief Executive Officer, Exelon Generation |
| Denis P. O'Brien | Senior EVP, Exelon; Chief Executive Officer, Exelon Utilities |
| William A. Von Hoene, Jr. | Senior EVP and Chief Strategy Officer, Exelon |

## Compensation Framework and 2014 Performance-based Pay Actions

| Element | Comments |
|---|---|
| Base Salary | - Salary increases as a result of the merit review averaged 2.3% for our NEOs (with 0% for the CEO).<br>- Base salary increases were provided to recognize individual performance and maintain market competitiveness. |
| Annual Incentive | - The total payout as a percent of target for our NEOs was 113.93%*, with the exception of Mr. O'Brien who received 116.83%.<br>- The total payout is inclusive of an individual performance multiplier of 110% for each NEO. |

* AIP weighting is 100% non-GAAP Operating EPS for all NEOs, with the exception of Mr. O'Brien.

| Element | Comments |
|---|---|
| Long-Term Incentive | - LTI consists of PSUs (67%) and RSUs (33%) and the goals of financial management (60%) and operational excellence (40%)**<br>- The 2014-2016 Long-Term Performance Share Award (LTPSA) vests in full in 2017, with final payout subject to a three-year TSR modifier and individual performance multiplier. |

** Each three-year goal has underlying metrics that can be modified annually on a forward-looking basis by the committee.

| Element | Comments |
|---|---|
| One-time Performance-based Transition Award (granted in 2013) | - One-third of the award vested in January 2014 based on a payout of 125.0%, which the committee reduced from 147.8%.*** The transition award was based on the same goals as the performance share program.<br>- For 2014, the second installment (67% targeted value) was paid out at 115.28% of target, reflecting the average of performance share program results for 2013 (125%) and 2014 (105.56%). |

*** The committee reduced the payout to better align with lagging shareholder returns, even though the company exhibited outstanding operational performance and solid financial performance.

## Pay at Risk

*Pay at risk in action.* Consistent with our pay-for-performance culture and to ensure alignment with shareholder interests, the committee recommends CEO pay decisions to the independent directors based on the core compensation principle of putting the majority of compensation in the form of variable pay that is at risk.

For example, 100% of Mr. Crane's 2014 total direct compensation adjustment of 3.8% was in the form of LTI.

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# Compensation Discussion & Analysis

## Base Salary

*Overview.* We pay base salaries to attract and retain talented executives and to provide a fixed level of cash compensation. Base salaries for our NEOs are set by the committee and adjusted following an annual market assessment of peer group compensation. Base salaries may be adjusted (1) as part of the annual merit review, or (2) based on a promotion or significant change in job scope. The committee considers the results of the annual market assessment in addition to the following factors when contemplating a merit review: individual performance, scope of responsibility, leadership skills and values, current compensation, internal equity, and legacy matters.

*2014 base salary adjustments.* The table below depicts 2014 base salary adjustments that were effective March 1, 2014. In the case of Mr. Thayer, a subsequent market adjustment was approved by the committee effective July 1, 2014 to reflect the addition of information technology, and supply chain to his portfolio of responsibilities.

| Name | Merit Increase | Market Adjustment |
|---|---|---|
| Crane | 0.0% | |
| Thayer | 3.7% | 7.1% |
| Cornew | 2.5% | |
| O'Brien | 2.5% | |
| Von Hoene, Jr. | 2.6% | |

## Performance-based Annual Incentive Program

*Overview.* We grant performance-based annual incentive awards to compensate our NEOs for achieving the company's annual performance goals. These awards represent a relatively small percentage of the executives' target total direct compensation (e.g., 12% for our CEO to about 18% for all other NEOs on average), as a majority of NEO pay is in the form of LTI. Both the AIP and the LTI are considered at risk and subject to recoupment in the case of a material negative adjustment of Exelon's financial or operational results, as provided in the recoupment policy described on page 54.

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# Compensation Discussion & Analysis

*Performance Goals.* The performance goal used to determine the annual incentives and bonuses for the named executive officers was non-GAAP operating EPS, which represents earnings directly related to ongoing operations of the business. Mr. O'Brien's AIP is based on a blend of EPS and the average operational and cost results for our three utilities (BGE, ComEd, and PECO). These goals were chosen because they reflect financial management and operational excellence goals that are associated with the creation of value for shareholders. Financial and operational goals are set at threshold (50%), target (100%) and distinguished (200%) levels based on objectives in the company's strategic business plan. The 2014 non-GAAP operating EPS target approved by the committee contains stretch goals based on the company's internal business plan. The committee set the operational goals based on industry performance benchmarks (where available).

| Target Annual Incentive Opportunity | X | Company/Business Unit Performance | X | Individual Performance Multiplier (IPM) | = | Actual Annual Incentive Award |
|---|---|---|---|---|---|---|
| · Expressed as % of base salary, as of 12/31/14<br>· CEO annual incentive target 125%<br>· Other NEO annual incentive targets range from 85% to 100% | | · Based on non-GAAP operating EPS for all NEOs, except Mr. O'Brien<br>· Performance is 0% to 200% (target of 100%) | | · Measures individual performance<br>· Ranges from 50% to 110% for NEOs (target of 100%)<br>· IPMs determined by the committee, with the exception of the CEO's IPM, which the independent directors approve | | · Maximum award of 200% of target |

*2014 Performance.* The committee approved a payout of 113.93%, based on adjusted non-GAAP operating EPS performance of 103.57% and an IPM of 110%, for each NEO, with the exception of Mr. O'Brien whose payout was 128.52%, based on an AIP performance factor of 116.83% and an IPM of 110%.

The following table shows how the formula was applied and the actual amounts awarded.

| NEO | Salary | | Target AIP% | | Performance Factor | | Total Award for 2014 Performance | | IPM% | | Actual Award |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Crane | $1,200,000 | x | 125% | x | 103.57% | = | $1,553,550 | x | 110% | = | $1,708,905 |
| Thayer | $ 750,000 | x | 95% | x | 103.57% | = | $ 737,946 | x | 110% | = | $ 811,741 |
| Cornew | $ 820,000 | x | 100% | x | 103.57% | = | $ 849,285 | x | 110% | = | $ 934,214 |
| O'Brien | $ 765,500 | x | 95% | x | 116.83% | = | $ 849,639 | x | 110% | = | $ 934,603 |
| Von Hoene, Jr. | $ 740,000 | x | 85% | x | 103.57% | = | $ 651,463 | x | 110% | = | $ 716,609 |

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# Compensation Discussion & Analysis

**Note: Adjusted (non-GAAP) Operating Earnings**
Adjusted (non-GAAP) operating earnings are provided as a supplement to results reported in accordance with GAAP. The adjustments generally exclude significant one-time charges or credits that are not normally associated with ongoing operations, mark-to-market adjustments from economic hedging activities and unrealized gains or losses from nuclear decommissioning trust fund adjustments. Management uses such adjusted (non-GAAP) operating earnings internally to evaluate the company's performance and manage its operations and externally to report performance to investors. Accordingly, management also uses adjusted (non-GAAP) operating earnings as a goal in its annual incentive plan. A reconciliation of adjusted (non-GAAP) operating earnings per share to reported GAAP earnings for 2014 is presented below; amounts may not add due to rounding:

| | |
|---|---|
| **2014 Adjusted (non-GAAP) Operating Earnings (Loss) Per Share** | **$ 2.39** |
| **Adjustments:** | |
| Mark-to-Market Impact of Economic Hedging Activities | (0.42) |
| Unrealized Gains Related to NDT Fund Investments | 0.10 |
| Plant Retirements and Divestitures | 0.28 |
| Asset Retirement Obligation Update | 0.02 |
| Merger and Integration Costs | (0.21) |
| Amortization of Commodity Contract Intangibles | (0.07) |
| Reassessment of State Deferred Income Taxes | 0.03 |
| Bargain-Purchase Gain on Integrys Acquisition | 0.03 |
| Gain on CENG Integration | 0.18 |
| Tax Settlements | 0.12 |
| Long-lived Asset Impairments | (0.50) |
| CENG Non-Controlling Interest | (0.07) |
| **2014 GAAP Earnings (Loss) Per Share** | **$ 1.88** |

The following table describes the performance scales and results for the 2014 goals:

| Goals | Threshold | Target | Distinguished | 2014 Results | Unadjusted Payout as a % of Target |
|---|---|---|---|---|---|
| Adjusted (non-GAAP) Operating Earnings Per Share (EPS) | $ 2.21 | $2.38 | $ 2.66 | $ 2.39 | 103.57% |
| Avg of BGE, ComEd and PECO Operational Results* | | Performance scale is a composite | | | 131.20% |
| Avg of BGE, ComEd and PECO Cost Results* | | of multiple measures | | | 101.36% |

* *Mr. O'Brien's performance factor differs from the other NEO's based on the following weighting: 25% Utilities cost measures, 25% Utilities operational measures, and 50% Operating EPS. His resultant performance factor is 116.83% prior to the application of the IPM.*

## 2014 LTI Awards

One of our central tenets of executive compensation is to "manage for the long-term" and we believe that execution against the company's strategy over multi-year periods will lead to an increase in long-term shareholder value creation. The LTI program for our senior vice presidents and higher officers (including our NEOs) consists of restricted stock units ("RSUs") and performance share units ("PSUs").

# Compensation Discussion & Analysis

The committee approves the annual equity grants at its meeting in January. On January 27, 2014, the committee approved the 2014 grants for RSUs, and PSUs, which are shown in detail in the Grants of Plan-Based Awards table on page 63.

The number of shares subject to each award type was based on the 2014 target awards that were approved by the committee. The grant date fair value of the awards based on the January 27, 2014 closing stock price of $28.20 is shown in the Summary Compensation Table, and the amounts of equity awards granted to each NEO are listed below as well as in the Grants of Plan-Based Awards table. Outstanding equity awards are shown in the Outstanding Equity Awards table.

*Restricted Stock Units.* RSUs vest ratably over three years. The committee believes that RSUs provide stability, foster retention and less volatility than other forms of LTI such as stock options, but are still linked to changes in shareholder value. Dividend equivalents with respect to RSUs are reinvested as additional RSUs, subject to the same vesting conditions as the underlying RSUs.

*Performance Share Units.* PSUs granted after 2012 vest in full after the three-year performance period. Each PSU represents the right to receive shares or cash to the extent performance goals are satisfied during the three year performance period. Performance periods overlap, with a new three- year performance cycle beginning each year. The committee can elect to modify the goal targets annually on a forward-looking basis to address unintended consequences with the challenges of setting three-year goals. At the end of each performance period, performance share units are awarded contingent upon the level of achievement of financial management and operational excellence goals as determined by the committee and subject to a total shareholder return modifier over three years relative to other competitive integrated companies that have at least 25% or more of their assets in unregulated businesses (Entergy, First Energy, NextEra Energy, PPL and PSEG). Settlement of PSUs is 50% in Exelon shares, with the balance in cash. The exception is for executive vice presidents and higher officers who have achieved 200% or more of their stock ownership target as of the September 30 measurement date of the year prior to payout, in which case the award is settled entirely in cash.

*How the Performance Share Units Work.* Each NEO's target performance share award is applied against the following:

| Average of 2014, 2015 and 2016 performance | x | Total Shareholder Return Modifier | x | Individual Performance Multiplier ("IPM") | = | Actual Performance Share Award |
|---|---|---|---|---|---|---|
| • Three year goals (financial management and operational excellence) | | • Total shareholder return measured over three years relative to peer group may increase or decrease the award up to 25% | | • IPM can decrease the award by up to 50% or increase the award by up to 10% | | • 150% Maximum award prior to total shareholder return and IPM (200% maximum after total shareholder return and IPM) |

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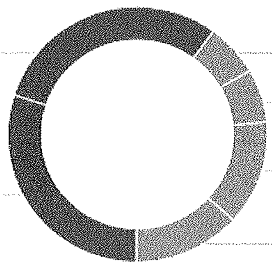
# Compensation Discussion & Analysis

*Performance Share Scorecard.* The 2014 performance share goals (financial management and operational excellence) have the underlying metrics shown in the scorecard below. The metrics were chosen for their correlation with driving long-term shareholder value creation.




**Financial Metrics**
- ROE: Measures the company's ability to generate earnings in relation to the amount of equity shareholders have invested in the company.
- FFO/Debt: Key ratio analyzed by the rating agencies in determining the company's credit rating.

**Operational Metrics**
- Outage Duration: Calculated as the total number of customer interruption minutes divided by the total number of customer interruptions. Applies to BGE, ComEd, and PECO for a total of three metrics.
- Outage Frequency: Calculated as the total number of customer interruptions divided by the total number of customers served. Applies to BGE, ComEd, and PECO for a total of three metrics.
- Net Fleetwide Capacity Factor: The weighted average of the capacity factor of all Exelon nuclear units, calculated as the sum of net generation in megawatt hours divided by the sum of the hourly annual mean net megawatt rating, multiplied by the number of hours in a period.
- Dispatch Match: Measure the responsiveness of a fossil generating unit to the market.

*2014 Performance Share Goal-Setting.* The following table shows the 2014 financial management and operational excellence goals, as well as the underlying metrics, which are set based on either the internal business plan or industry performance. All metrics are designed to be challenging to achieve and were chosen because they are key measures for driving long-term success for Exelon.

**Goal Rigor:** In setting targets for 2014, the committee set eight of the ten underlying metrics at a more challenging level than the prior year.

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# Compensation Discussion & Analysis

**2014 Performance Share Scorecard**

| Goals / Weighting | Metrics | Metric Weighting | Operating Company | Threshold* | Target* | Target Calibrated to | Distinguished | Final Score | Actual Award vs. Metric Weighting |
|---|---|---|---|---|---|---|---|---|---|
| Financial Management: 60% | ROE | 30.0% | Exelon Corp | 7.0% | 8.0% | Budget | 9.0% | 8.22% | 30.00% |
| | FFO /Debt | 30.0% | ExGen HoldCo | 39.0% | 40.6% | Budget | 43.1% | 41.0% | 30.00% |
| Operational Excellence: 40% | Outage Duration (Average) | 6.7% | BGE | 113.0 | 95.0 | 2nd Quartile | 91.5 | 92.0 | 2.79% |
| | | | ComEd | 94.0 | 85.0 | 1st Quartile | 84.0 | 84.0 | 3.35% |
| | | | PECO | 94.0 | 88.0 | 1st Quartile | 85.5 | 90.0 | 1.68% |
| | Outage Frequency (Average) | 6.7% | BGE | 1.12 | 0.97 | 2nd Quartile | 0.91 | 0.77 | 3.35% |
| | | | ComEd | 0.90 | 0.78 | 1st Decile | 0.76 | 0.81 | 1.68% |
| | | | PECO | 0.90 | 0.78 | 1st Decile | 0.76 | 0.77 | 2.79% |
| | Net Fleetwide Capacity Factor | 13.3% | Nuclear | 91.3% | 93.3% | 1st Quartile | 93.8% | 94.2% | 19.95% |
| | Dispatch Match | 13.3% | Power | 95.1% | 97.1% | Internal measure | 97.9% | 96.5% | 9.98% |
| | | | | | | | | **Formulaic Payout** | **105.56%** |

* *Lower number is better for outage duration and outage frequency, and higher for all other metrics.*

## One-time Performance-based Transition Award

As we discussed in last year's proxy statement, the committee approved a one-time performance-based transition award in 2013 that replaced lost targeted LTI payments resulting from lengthening the performance period to three years from one year. The first installment of the transition award (representing 33% of the targeted value) was paid in January 2014 at 125% of target based on 2013 performance share results. The second installment (representing 67% of targeted value) was paid in January 2015 at 115.28% of target based on the average 2013 (125%) and 2014 (105.56%) performance share results.

*Payout of the Second Installment of the Transition Award.* Share payouts for the NEOs are shown in the table below. Payouts were settled entirely in cash for all NEOs due to their having achieved over 200% of their stock ownership targets as of the measurement date of September 30, 2014.

| NEO | Second Installment Target Shares | | Performance Factor | | Actual Share Award |
|---|---|---|---|---|---|
| Crane | 79,266 | x | 115.28% | = | 91,378 |
| Thayer | 21,229 | x | 115.28% | = | 24,473 |
| Cornew | 24,000 | x | 115.28% | = | 27,667 |
| O'Brien | 20,333 | x | 115.28% | = | 23,440 |
| Von Hoene, Jr. | 17,599 | x | 115.28% | = | 20,288 |

### *Section IV: Governance Features of Our Executive Compensation Programs*

## CEO Annual Performance Assessment

On an annual basis, the independent directors of the Exelon board conduct a thorough review of CEO performance. In 2014, the review considered the extent of Mr. Crane's achievement in executing against Exelon's strategy to ***leverage our integrated business model to create value and diversify our business.*** In addition, the board considered Exelon's 2014 stock price performance (+40.6% total shareholder return), financial (beat plan for EPS) and operational performance (best-in-class or first decile performance against industry standards on several metrics). Mr. Crane prepared a detailed self-

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# Compensation Discussion & Analysis

assessment reporting to the board on his performance during the year with respect to each of the performance requirements. The Exelon board considered the financial highlights of the year and a strategy scorecard that assessed performance against the company's vision and goals. This review was considered in making decisions regarding Mr. Crane's compensation.

## Stock Ownership and Trading Requirements

To strengthen the alignment of executives' interests with those of shareholders, officers of the company are required to own certain amounts of Exelon common stock. In 2012, following the merger with Constellation, Exelon reviewed the ownership requirements and updated the guidelines. Executives must meet these guidelines within five years after the later of the implementation of the new guidelines, their employment or promotion to a new position. As of the annual measurement date of September 30, 2014, all NEOs had an achievement level that exceeded 200% of their stock ownership guidelines as shown in the table below:

| Name | Required Minimum Ownership | Ownership as of Sept 30, 2014 |
|---|---|---|
| Crane | 5 times base salary* | 234% (of 5x) |
| Thayer | 3 times base salary | 230% (of 3x) |
| Cornew | 3 times base salary | 243% (of 3x) |
| O'Brien | 3 times base salary | 221% (of 3x) |
| Von Hoene, Jr. | 3 times base salary | 243% (of 3x) |

* *Starting in 2015, Mr. Crane's required minimum ownership is 6 times his base salary. Mr. Crane meets this requirement.*

For additional information about Exelon's stock ownership guidelines, please see the Stock Ownership Requirements for Directors and Officers and Beneficial Ownership Table on pages 28-29, respectively.

Exelon has adopted a policy requiring executive vice presidents and higher officers who wish to sell Exelon common stock to do so only through Rule 10b5-1 stock trading plans, and permitting other officers to enter into such plans. This requirement is designed to enable officers to diversify a portion of their holdings in excess of the applicable stock ownership requirements in an orderly manner as part of their retirement and tax planning activities. The use of Rule 10b5-1 stock trading plans serves to reduce the risk that investors will view routine portfolio diversification stock sales by executive officers as a signal of negative expectations with respect to the future value of Exelon's stock. In addition, the use of Rule 10b5-1 stock trading plans reduces the potential for accusations of trading on the basis of material, non-public information, which could damage the reputation of the company. Exelon's stock trading policy does not permit short sales, hedging or pledging.

## Recoupment (Clawback) Policy

Consistent with the pay-for-performance policy, in May 2007, the board of directors adopted a recoupment policy as part of Exelon's Corporate Governance Principles. The board of directors will seek recoupment of incentive compensation paid to an executive officer if the board determines, in its sole discretion, that:

- the executive officer engaged in fraud or intentional misconduct;
- as a result of which Exelon was required to materially restate its financial results;
- the executive officer was paid more incentive compensation than would have been payable had the financial results been as restated;
- recoupment is not precluded by applicable law or employment agreements; and
- the board concludes that, under the facts and circumstances, seeking recoupment would be in the best interest of Exelon and its shareholders.

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# Compensation Discussion & Analysis

## Compensation Policies and Practices as They Relate to Risk Management

The compensation and leadership development committee has considered Exelon's policies and practices of compensating its employees, including non-executive officers, as they relate to risk management practices and risk-taking incentives and believes that such policies and practices are not reasonably likely to have a material adverse effect on Exelon. In this regard, the committee considered the following factors:

- The annual and long-term incentive programs place limits on incentive compensation grants and awards.
- Incentive goals are not tailored solely to revenue-generating conduct.
- The annual incentive program key performance indicators are reviewed in a challenge session by a senior management panel to make sure the goals are fair, reasonable, aligned with the overall business plan and balanced between financial and operational excellence.
- The annual incentive program contains features that limit payouts on operating company and business unit key performance indicators where the payout would exceed 120% of target, and the compensation and leadership development committee reserves the right to curtail awards if a business unit under-performs.
- Exelon has long-term incentive programs that are linked to shareholder value.
- Exelon's officers are required to own Exelon stock, and performance share units are paid out over a two year period after they are earned (program prior to 2013) or after a three-year performance period (program since 2013).
- The Exelon Long-term Incentive Plan provides that the compensation and leadership development committee may amend or adjust the performance measures or other terms and conditions of an outstanding award in recognition of unusual or nonrecurring events affecting the company or its financial statements or changes in law or accounting principles.
- The company has a recoupment policy.

Although the foregoing factors address financial risks, the committee also considered that Exelon's policies and practices include measures to make sure that the cost reduction and other goals designed to address financial performance do not present significant operational risk issues. These measures include the following:

- For employees and all officers with business unit responsibilities, the annual incentive compensation program includes measures based on business unit operating measures, such as safety and reliability.
- Management carefully tracks a variety of safety and reliability metrics on a routine basis to make sure that performance is not adversely affected by such things as cost reduction efforts.

## Tax Consequences

Under Section 162(m) of the Internal Revenue Code, executive compensation in excess of $1 million paid to a CEO or other person among the three other highest compensated officers (excluding the CFO) is generally not deductible for purposes of corporate federal income taxes. However, qualified performance-based compensation, within the meaning of Section 162(m) and applicable regulations, remains deductible. The compensation and leadership development committee intends to continue reliance on performance-based compensation programs, consistent with sound executive compensation policy. The committee's policy has been to seek to cause executive incentive compensation to qualify as "performance-based" in order to preserve its deductibility for federal income tax purposes to the extent possible, without sacrificing flexibility in designing appropriate compensation programs.

Because it is not "qualified performance-based compensation" within the meaning of Section 162(m), base salary is not eligible for a federal income tax deduction to the extent that it exceeds $1 million. Accordingly, Exelon is unable to deduct

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# Compensation Discussion & Analysis

that portion of Mr. Crane's base salary in excess of $1 million. Annual incentive awards and performance share units payable to NEOs are intended to be qualified performance-based compensation under Section 162(m), and to be deductible for federal income tax purposes. Restricted stock and restricted stock units are not deductible by the company for federal income tax purposes under the provisions of Section 162(m) to the extent an NEO's compensation that is not "qualified performance-based compensation" is in excess of $1 million.

In order to qualify payments under the AIP and performance share program as performance-based for Section 162(m) of the Internal Revenue Code, the committee uses a "plan-within-plan" two-step approach to determine the amount of the bonus payment. The first step is to fund the overall bonus pool. The pool is funded if the company meets the pre-established performance metrics. The second step is accomplished when the committee exercises "negative discretion" by making adjustments to the formula award funded by the overall pool. Negative discretion is used to reduce the amount funded by the pool to an amount equal to the target bonus (for AIP) or target equity (for the performance share program) adjusted for final company performance and individual performance.

Under Section 4999 of the Internal Revenue Code, there is an excise tax if change-in-control or severance benefits are greater than 2.99 times the five-year average amount of income reported on an individual's W-2. In April 2009 the compensation committee adopted a policy that no future employment or severance agreements that provide for benefits for NEOs on account of termination will include an excise tax gross-up. However, certain NEOs have change in control severance agreements that pre-date April 2009 and provide excise tax gross-ups, and avoid gross-ups by reducing payments to under the threshold if the amount otherwise payable to an executive is not more than 110% of the threshold.

# Executive Compensation Data

## Executive Compensation

The tables below summarize the total compensation paid or earned by each of the Named Executive Officers (NEOs) of Exelon for the year ended December 31, 2014, presented in accordance with SEC requirements. Basic information about the elements of compensation as disclosed in the tables is shown below:

**Salary:**

- Amounts may not match the amounts discussed in Compensation Discussion and Analysis because that discussion concerns salary rates; the amounts reported in the Summary Compensation Table reflect actual salaries paid during the year including the effect of changes in salary rates.
- Changes to base salary generally take effect on March 1. There may also be changes at other times during the year to reflect promotions or changes in responsibilities.

**Bonus:**

- Reflects discretionary bonuses or amounts paid under the annual incentive plan on the basis of the individual performance multiplier or discretionary amounts approved by the compensation and leadership development committee or, in the case of Mr. Crane, approved by the independent directors.

**Stock Awards:**

- Values reported show the grant date fair value calculated in accordance with FASB ASC Topic 718.
- Consist primarily of performance share unit awards and restricted stock unit awards pursuant to the terms of the 2011 Long-Term Incentive Plan.
- Since 2013 award mix is 67% performance share units and 33% restricted stock units; stock options are no longer granted.

**Performance Share Units:**

- Compensation and leadership development committee redesigned structure in 2013.
  - Reduced goal categories from six to two: financial management (weighted at 60%) and operational excellence (weighted at 40%). Within the goal categories there are quantitative metrics.
  - Performance period lengthened from one to three years.
- Maximum payout for performance share units is 150% of target; threshold payout is 50% of target.
- Total shareholder return reinstated as a formulaic award modifier. Awards can be increased or decreased by up to 25% based on total shareholder return performance relative to other energy services companies with business models most similar to ours.
- Individual performance multiplier can increase awards up to 10% or reduce awards by 50%.
- Threshold, target and distinguished goals for performance share unit awards established on the grant date (generally the date of the first committee meeting in the first year in the performance period).
  - Actual performance against the goals for each year in the performance period established at the first committee meeting after the completion of the year.
  - At the end of the three-year performance period awards are made based on the average of the level of performance for each of the three years in the performance period, and the award date is the date of the first committee meeting after the completion of the third year in the performance period.

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# Executive Compensation Data

- Under the new design, performance shares vest immediately; under the former one-year performance period structure, awards vested one-third upon award with one-third vesting on the date of the next two January committee meetings.
- Performance share awards are settled 50% in Exelon common stock and 50% in cash, except for executive vice presidents and higher officers whose awards are paid 100% in cash if the officer has attained 200% of the applicable stock ownership requirement.

**Transition Awards:**

- One-time grant of transition awards made in 2013 in connection with the transition to the three-year performance period for performance shares so that the amount of performance share awards vesting each year would be consistent during the period until the 2013-15 performance shares vest.
- Transition awards use the same goals and metrics as the performance shares, except that the total shareholder return modifier and individual performance multipliers do not apply.

**Restricted Stock Units:**

- Vest ratably on the date of the next three January committee meetings.
- In limited cases, restricted stock units granted to executives as a means to recruit and retain talent.
  - May be used for new hires to offset annual or long-term incentives forfeited from a previous employer.
  - May also be used as a retention vehicle, vesting after pre-determined period of time and subject to forfeiture upon voluntarily termination.
  - May incorporate performance criteria as well as time-based vesting.
- Amounts of restricted shares held by each NEO shown in the footnotes to the Outstanding Equity Table.

**Stock Options:**

- Not granted since 2012.
- Prior to 2013 made pursuant to terms of Long-Term Incentive Plan.
- Granted at a strike price that was not less than the fair market value of a share of stock on the date of grant.
  - Fair market value was defined under the plans as the closing price on the grant date as reported on the New York Stock Exchange.
  - Individuals receiving stock options were provided right to buy fixed number of shares of Exelon common stock at the closing price on the grant date.
  - Target for the number of options awarded determined by the portion of the long-term incentive value attributable to stock options and a theoretical value of each option determined by the committee using a lattice binomial ratio valuation formula.
- Options vest in equal annual installments over a four-year period and have a term of 10 years. Employees who are retirement eligible are eligible for accelerated vesting upon retirement or termination without cause. Time vesting adds a retention element to the stock option program.
- Under the terms of the Long-Term Incentive Plan stock options may not be re-priced or cashed out.

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# Executive Compensation Data

**Non-equity incentive plan compensation:**

- Includes amounts earned under the annual incentive plan, determined by the extent to which the applicable financial and operational goals were achieved.
- Amount of the annual incentive target opportunity expressed as a percentage of base salary, with actual awards determined using the base salary at the end of the year.
- Threshold, target and distinguished (i.e. maximum) achievement levels established for each goal.
  - Threshold set at the minimally acceptable level of performance, for a payout of 50% of target.
  - Target set consistent with the achievement of the business plan objectives.
  - Distinguished set at a level that significantly exceeds the business plan and has a low probability of payout, capped at 200% of target.
  - Awards interpolated to the extent performance falls between the threshold, target, and distinguished levels.

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# Executive Compensation Data

## *Summary Compensation Table*

| Year (a) | Salary ($) (b) | Bonus ($) Note 1 (c) | Stock Awards ($) Note 2 (d) | Option Awards ($) Note 3 (e) | Non-Equity Incentive Plan Compensation ($) Note 4 (f) | Change in Pension Value and Nonqualified Deferred Compen-sation Earnings ($) Note 5 (g) | All Other Compen-sation ($) Note 6 (h) | Total ($) (i) |
|---|---|---|---|---|---|---|---|---|
| **Christopher M. Crane** | | | | | | | | |
| **President and Chief Executive Officer, Exelon** | | | | | | | | |
| 2014 | $ 1,200,000 | $ 155,355 | $ 9,345,480 | $ — | $ 1,553,550 | $ 2,431,986 | $ 304,459 | $ 14,990,830 |
| 2013 | 1,191,539 | — | 12,606,074 | — | 1,565,250 | 1,584,841 | 243,994 | 17,191,698 |
| 2012 | 1,078,750 | 131,100 | 4,234,680 | 1,191,300 | 1,311,000 | 2,063,852 | 190,568 | 10,201,250 |
| **Jonathan W. Thayer** | | | | | | | | |
| **Senior Executive Vice President and Chief Financial Officer, Exelon** | | | | | | | | |
| 2014 | 717,597 | 73,795 | 2,974,199 | — | 737,946 | 166,783 | 85,008 | 4,755,328 |
| 2013 | 670,193 | — | 4,000,394 | — | 633,913 | 162,252 | 254,815 | 5,721,567 |
| 2012 | 500,000 | 55,575 | 1,433,160 | 405,460 | 555,750 | 154,502 | 128,519 | 3,232,966 |
| **Kenneth W. Cornew** | | | | | | | | |
| **Senior Executive Vice President and Chief Commercial Officer, Exelon; President and Chief Executive Officer, Exelon Generation** | | | | | | | | |
| 2014 | 815,769 | 84,929 | 2,822,820 | — | 849,285 | 194,029 | 55,193 | 4,822,025 |
| 2013 | 760,392 | — | 4,715,518 | — | 834,782 | 219,293 | 37,349 | 6,567,334 |
| **Denis P. O'Brien** | | | | | | | | |
| **Senior Executive Vice President, Exelon; Chief Executive Officer, Exelon Utilities** | | | | | | | | |
| 2014 | 761,534 | 84,964 | 2,382,900 | — | 849,639 | 299,132 | 54,936 | 4,433,105 |
| 2013 | 742,233 | — | 3,233,366 | — | 811,205 | 411,426 | 43,984 | 5,242,214 |
| 2012 | 686,923 | 68,513 | 1,513,540 | 426,360 | 685,125 | 248,744 | 50,999 | 3,680,204 |
| **William A. Von Hoene Jr.** | | | | | | | | |
| **Senior Executive Vice President and Chief Strategy Officer, Exelon** | | | | | | | | |
| 2014 | 736,710 | 65,146 | 2,067,060 | — | 651,463 | 161,623 | 97,304 | 3,779,306 |
| 2013 | 717,446 | — | 3,371,564 | — | 639,495 | 179,014 | 74,359 | 4,981,878 |
| 2012 | 685,577 | 56,525 | 1,314,390 | 367,840 | 565,250 | 135,601 | 67,338 | 3,192,601 |

**Notes to the Summary Compensation Table**

(1) *In recognition of their overall performance, certain executives may receive an individual performance multiplier to their annual incentive payments or other special recognition awards in certain years. For 2014, all NEOs received an individual performance multiplier.*

(2) *The amounts shown in this column include the aggregate grant date fair value of restricted stock unit and performance share unit awards for the 2014-2016 performance period granted on January 27, 2014 as well as a supplemental grant on July 1, 2014 for Mr. Thayer with respect to his promotion. The grant date fair values of the stock awards have been computed in accordance with FASB ASC Topic 718 using the assumptions described in Note 17 of the Combined Notes to Consolidated Financial Statements included in Exelon's 2014 Annual Report on Form 10-K. The performance share unit awards are subject to performance conditions. For the 2014-2016 performance share unit award, the grant date fair value and the value assuming the highest level of performance, including the maximum total shareholder return multiplier and the maximum individual performance multiplier, is as follows:*

| | Performance Share Unit Value | |
|---|---|---|
| | At Target | At Maximum |
| Crane | $ 6,280,140 | $ 12,560,280 |
| Thayer | 1,796,040 | 3,592,080 |
| Cornew | 1,880,940 | 3,761,880 |
| O'Brien | 1,596,120 | 3,192,240 |
| Von Hoene Jr. | 1,381,800 | 2,763,600 |

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# Executive Compensation Data

(3) *The amounts shown in this column include the aggregate grant date fair value of stock option awards granted. No stock options were granted to the NEOs in 2014 or 2013.*
(4) *The amounts shown in this column for 2014 represent payments made pursuant to the Annual Incentive Plan.*
(5) *The amounts shown in this column represent the change in the accumulated pension benefit for the NEOs from December 31, 2013 to December 31, 2014. None of the NEOs had above market earnings in a non-qualified deferred compensation account in 2014.*
(6) *The amounts shown in this column include the items summarized in the following table:*

## All Other Compensation

| Name (a) | Perquisites ($) Note 1 (b) | Reimbursement for Income Taxes ($) Note 2 (c) | Payments or Accruals For Termination or Change in Control (CIC) ($) Note 3 (d) | Company Contributions to Savings Plans ($) Note 4 (e) | Company Paid Term Life Insurance Premiums ($) Note 5 (f) | Dividends or Earnings Not Included in Grants ($) (g) | Total ($) (h) |
|---|---|---|---|---|---|---|---|
| Crane | $ 152,699 | $ 80,052 | $ — | $ 42,001 | $ 29,707 | $ — | $304,459 |
| Thayer | 18,596 | 54,921 | — | 7,930 | 3,561 | — | 85,008 |
| Cornew | 20,795 | 2,093 | — | 28,553 | 3,752 | — | 55,193 |
| O'Brien | 16,265 | — | — | 26,654 | 12,017 | — | 54,936 |
| Von Hoene Jr. | 45,290 | 20,269 | — | 25,785 | 5,960 | — | 97,304 |

**Notes to All Other Compensation Table**
(1) *The amounts shown in this column represent the incremental cost to Exelon to provide certain perquisites to NEOs as summarized in the Perquisites Table below.*
(2) *Employees receive a reimbursement to cover applicable taxes when they work out of their home state and encounter double taxation in states and localities where they would not be eligible to receive a credit for such taxes when filing their tax returns in their home state, as well as on imputed income for business-related spousal travel expenses for those cases where the personal benefit is closely related to the business purpose, and for relocation expenses when the employee is required to relocate.*
(3) *Represents the expense, if applicable, or the accrual of the expense that Exelon has recorded during 2014 after the announcement of the officer's retirement or resignation for severance related costs including salary and Annual Incentive Plan continuation and other benefits as applicable.*
(4) *Represents company matching contributions to the NEOs' qualified and non-qualified savings plans. The 401(k) plan is available to all employees and the annual contribution for 2014 was generally limited by IRS rules to $17,500, although employees over age 50 can make additional "catch-up" contributions of up to $5,500. NEOs and other officers may participate in the Deferred Compensation Plan, into which payroll contributions in excess of the specified IRS limit are credited under a separate, unfunded plan that has the same portfolio of investment options as the 401(k) plan.*
(5) *Exelon provides basic term life insurance, accidental death and disability insurance, and long-term disability insurance to all employees, including NEOs. The values shown in this column include the premiums paid during 2014 for additional term life insurance policies for the NEOs and for additional long-term disability insurance over and above the basic coverage provided to all employees.*

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# Executive Compensation Data

## Perquisites

The following table indicates the various perquisites for which Exelon incurred incremental costs in 2014 for each NEO. A checkmark (✓) indicates perquisite usage during 2014 by the NEO listed at the top of the column.

| Perquisite | Crane | Thayer | Cornew | O'Brien | Von Hoene Jr. |
|---|---|---|---|---|---|
| Personal use of corporate aircraft (1) | ✓ | | | | ✓ |
| Personal use of company drivers (2) | ✓ | ✓ | | | ✓ |
| Financial planning (3) | | | ✓ | ✓ | ✓ |
| Parking (4) | ✓ | ✓ | ✓ | | ✓ |
| Company gifts and matching contributions (5) | ✓ | ✓ | ✓ | ✓ | ✓ |
| Physical examinations (6) | | | | ✓ | |
| Event tickets (7) | | | ✓ | | |

**Notes to Perquisites Table**

(1) *The figures shown in column (b) of the All Other Compensation Table above include $130,015 representing the aggregate incremental cost to Exelon for personal use of corporate aircraft by Mr. Crane, and $26,569 for Mr. Von Hoene who was permitted to use corporate aircraft on two occasions in 2014. These costs were calculated using the hourly incremental cost for flight services, including federal excise taxes, fuel charges, and domestic segment fees. From time to time Mr. Crane's spouse, or other family members, accompanied him in his travel on corporate aircraft. The aggregate incremental cost to the company, if any, for such travel by spouses or family members on corporate aircraft is included in this amount.*

(2) *The company maintains several cars and drivers in order to provide transportation services for the NEOs and other officers to carry out their duties among the company's various offices and facilities. Certain NEOs were also entitled to limited personal use of the company's cars and drivers, including use for commuting which allowed them to work while commuting. The cost included in the All Other Compensation Table represents the estimated incremental cost to Exelon to provide limited personal service, based upon the number of hours that the drivers worked overtime providing services to each NEO, multiplied by the average overtime rate for drivers plus an additional amount for fuel. Personal use was imputed as additional taxable income.*

(3) *The company will pay limited annual financial planning costs for executives that are imputed as additional taxable income.*

(4) *For NEOs whose primary work location is downtown Chicago, Exelon's office lease provides for a limited number of parking spaces that are available for Exelon use. When NEOs are unable to utilize the available spaces, Exelon pays for parking expenses incurred at other public garages. Messrs. Thayer and Cornew have company provided spaces in downtown Baltimore.*

(5) *Executive officers may also have the company make matching gifts to qualified charitable organizations up to $10,000 for 2014. Mr. Thayer was subject to a $15,000 annual limit under Constellation's legacy policy.*

(6) *Executive officers may use company-provided vendors for comprehensive physical examinations and related follow-up testing.*

(7) *Executives occasionally receive tickets to sporting or other events as recognition awards that are imputed to the officer as additional taxable income.*

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# Executive Compensation Data

## *Grants of Plan-Based Awards*

| | | Estimated Possible Payouts Under Non-Equity Incentive Plan Awards (Note 1) | | | Estimated Possible Payouts Under Equity Incentive Plan Awards (Note 2) | | | All Other Stock Awards: Number of Shares or Units (#) (Note 3) | All Other Options Awards: Number of Securities Under-lying Options (#) | Exercise or Base Price of Option Awards ($) | Grant Date Fair Value of Stock and Option Awards ($) (Note 4) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Name (a) | Grant Date (b) | Thres-hold ($) (c) | Plan ($) (d) | Maxi-mum ($) (e) | Thres-hold (#) (f) | Target (#) (g) | Maxi-mum (#) (h) | (i) | (j) | (k) | (l) |
| Crane | 1/27/2014 | $750,000 | $1,500,000 | $3,000,000 | | | | | | | |
| | 1/27/2014 | | | | 41,756 | 222,700 | 445,400 | | | | $6,280,140 |
| | 1/27/2014 | | | | | | | 108,700 | | | 3,065,340 |
| Thayer [5] | 1/27/2014 | 356,250 | 712,500 | 1,425,000 | | | | | | | |
| | 1/27/2014 | | | | 10,613 | 56,600 | 113,200 | | | | 1,596,120 |
| | 7/1/2014 | | | | 3,419 | 14,963 | 28,945 | | | | 534,179 |
| | 1/27/2014 | | | | | | | 27,900 | | | 786,780 |
| | 7/1/2014 | | | | | | | 1,600 | | | 57,120 |
| Cornew | 1/27/2014 | 410,000 | 820,000 | 1,640,000 | | | | | | | |
| | 1/27/2014 | | | | 12,506 | 66,700 | 133,400 | | | | 1,880,940 |
| | 1/27/2014 | | | | | | | 33,400 | | | 941,880 |
| O'Brien | 1/27/2014 | 363,613 | 727,226 | 1,454,452 | | | | | | | |
| | 1/27/2014 | | | | 10,613 | 56,600 | 113,200 | | | | 1,596,120 |
| | 1/27/2014 | | | | | | | 27,900 | | | 786,780 |
| Von Hoene Jr. | 1/27/2014 | 314,500 | 628,999 | 1,257,998 | | | | | | | |
| | 1/27/2014 | | | | 9,188 | 49,000 | 98,000 | | | | 1,381,800 |
| | 1/27/2014 | | | | | | | 24,300 | | | 685,260 |

**Notes to Grants of Plan-Based Awards Table**

(1) *All NEOs have annual incentive plan target opportunities based on a fixed percentage of their base salary. Under the terms of the AIP, threshold performance earns 50% of the respective target, while performance at plan earns 100% of the respective target and the maximum payout is capped at 200% of target. For additional information about the terms of these programs, see Compensation Discussion and Analysis above.*

(2) *NEOs have a long-term performance share unit target opportunity that is a fixed number of performance share units commensurate with the officer's position. The possible payout at threshold for performance share unit awards was calculated at 50% of target, with a total shareholder return multiplier of 75% and an individual performance multiplier of 50%. The possible maximum payout for performance share units was calculated at 150% of target, with a total shareholder return multiplier of 125% and an individual performance multiplier of 110%, capped at 200% of target. For additional information about the terms of this program, see Compensation Discussion and Analysis and the narrative preceding the Summary Compensation Table above.*

(3) *This column shows restricted share unit awards made during the year. The vesting dates of the awards are provided in footnote 2 to the Outstanding Equity Table below.*

(4) *This column shows the grant date fair value, calculated in accordance with FASB ASC Topic 718, of the performance share unit awards, performance-based transition awards, and restricted stock granted to each NEO during 2014. Fair value of performance share unit awards and performance-based transition awards granted on January 27, 2014 and July 1, 2014 are based on an estimated payout of 100% of target.*

(5) *Mr. Thayer received prorated awards to his 2013 and 2014 performance share unit target opportunity and his one-time performance-based transition award target opportunity due to a promotion. The threshold and maximum for the 2013 performance share units are calculated the same as the 2014 performance share units. The possible payout at threshold for the performance-based transition award was calculated at 50% of target, and the possible maximum payout was calculated at 150% of target; the total shareholder return and individual performance multipliers do not apply to the performance-based transition award.*

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# Executive Compensation Data

## *Outstanding Equity Awards at Year End*

| Name (a) | Option Awards (See Note 1) | | | | Stock Awards | | | |
|---|---|---|---|---|---|---|---|---|
| | Number of Securities Underlying Unexercised Options That Are Exercisable (#) (b) | Number of Securities Underlying Unexercised Options That Are Not Exercisable (#) (c) | Option Exercise or Base Price ($) (d) | Option Expiration Date (e) | Number of Shares or Units of Stock That Have Not Yet Vested (#) (Note 2) (f) | Market Value of Shares or Units of Stock That Have Not Yet Vested Based on 12/31 Closing Price $37.08 ($) (Note 2) (g) | Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That Have Not Yet Vested (#) (Note 3) (h) | Equity Incentive Plan Awards: Market or Payout Value or Unearned Shares, Units or Other Rights That Have Not Yet Vested ($) (Note 3) (i) |
| Crane | 142,500 | 142,500 | $ 39.21 | 2-Apr-2022 | 316,720 | $ 11,743,978 | 827,800 | $ 30,694,824 |
| | 70,500 | 23,500 | 43.40 | 24-Jan-2021 | | | | |
| | 53,000 | — | 46.09 | 24-Jan-2020 | | | | |
| | 49,000 | — | 56.51 | 26-Jan-2019 | | | | |
| | 28,000 | — | 73.29 | 27-Jan-2018 | | | | |
| | 35,000 | — | 59.96 | 21-Jan-2017 | | | | |
| | 22,500 | — | 58.55 | 22-Jan-2016 | | | | |
| | 18,000 | — | 42.65 | 23-Jan-2015 | | | | |
| Thayer | 46,500 | 48,500 | 39.81 | 12-Mar-2022 | 123,305 | 4,572,149 | 206,000 | 7,638,480 |
| | 117,298 | 56,648 | 39.24 | 24-Feb-2022 | | | | |
| | 125,429 | — | 32.46 | 25-Feb-2021 | | | | |
| | 67,304 | — | 37.71 | 26-Feb-2020 | | | | |
| | 167,669 | — | 21.25 | 27-Feb-2019 | | | | |
| | 8,676 | — | 101.05 | 21-Feb-2018 | | | | |
| | 8,342 | — | 81.56 | 22-Feb-2017 | | | | |
| | 5,487 | — | 54.80 | 24-Feb-2015 | | | | |
| Cornew | 35,000 | 35,000 | 39.81 | 12-Mar-2022 | 132,957 | 4,930,046 | 249,000 | 9,232,920 |
| | 19,500 | 6,500 | 43.40 | 24-Jan-2021 | | | | |
| | 13,300 | — | 46.09 | 24-Jan-2020 | | | | |
| | 14,900 | — | 56.51 | 26-Jan-2019 | | | | |
| | 11,000 | — | 73.29 | 27-Jan-2018 | | | | |
| | 8,500 | — | 59.96 | 21-Jan-2017 | | | | |
| | 6,375 | — | 58.55 | 22-Jan-2016 | | | | |
| | 5,550 | — | 42.85 | 23-Jan-2015 | | | | |
| O'Brien | 51,000 | 51,000 | 39.81 | 12-Mar-2022 | 85,579 | 3,173,269 | 211,200 | 7,831,296 |
| | 36,750 | 12,250 | 43.40 | 24-Jan-2021 | | | | |
| | 27,000 | — | 46.09 | 24-Jan-2020 | | | | |
| | 30,700 | — | 56.51 | 26-Jan-2019 | | | | |
| | 22,000 | — | 73.29 | 27-Jan-2018 | | | | |
| | 19,000 | — | 59.96 | 21-Jan-2017 | | | | |
| | 20,000 | — | 58.55 | 22-Jan-2016 | | | | |
| | 29,000 | — | 42.85 | 23-Jan-2015 | | | | |
| Von Hoene Jr. | 44,000 | 44,000 | 39.81 | 12-Mar-2022 | 94,314 | 3,497,163 | 182,800 | $ 6,778,224 |
| | 50,250 | 16,750 | 43.40 | 24-Jan-2021 | | | | |
| | 33,000 | — | 46.09 | 24-Jan-2020 | | | | |
| | 25,200 | — | 56.51 | 26-Jan-2019 | | | | |
| | 19,000 | — | 73.29 | 27-Jan-2018 | | | | |
| | 19,000 | — | 59.96 | 21-Jan-2017 | | | | |
| | 17,000 | — | 58.55 | 22-Jan-2016 | | | | |
| | 14,000 | — | 42.85 | 23-Jan-2015 | | | | |
| | 4,500 | — | 32.54 | 25-Jan-2014 | | | | |

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# Executive Compensation Data

**Notes to Outstanding Equity Table**

(1) *Non-qualified stock options were granted to NEOs pursuant to the company's long-term incentive plans. Grants vest in four equal increments, beginning on the first anniversary of the grant date. All grants expire on the tenth anniversary of the grant date. For Mr. Thayer, stock options granted prior to March 12, 2012 were granted under the Constellation Energy Group Inc. Long Term Incentive Plan and were converted into the equivalent right to receive Exelon common stock. The number of stock options received upon conversion is equal to the original number of Constellation stock options multiplied by the merger exchange ratio (0.93) and rounded down to the nearest whole share. The exercise price for each converted share is equal to the original Constellation exercise price divided by the exchange ratio (0.93), rounded up to the nearest whole cent.*

(2) *The amount shown includes the unvested portion of the performance share unit award earned with respect to the three-year performance period ending December 31, 2012; the remaining two-thirds of the transition award grant made in January 2013 that was earned based on averaging the results of the 2013 and 2014 performance periods, which resulted in a payout of 115.28% of target and will vest in January 2015; and any unvested restricted stock unit awards as shown in the following table. Shares are valued at $37.08, the closing price on December 31, 2014.*

(3) *The amount shown includes the target performance share unit award made in January 2013 for the performance period ending December 31, 2015 and the target performance share unit award made in January 2014 for the performance period ending December 31, 2016. These target awards have been increased to reflect the highest level of performance for the period.*

## Unvested Restricted Stock or Restricted Stock Units and Transition Award

| Name (a) | Grant Date (b) | Number of Restricted Shares (#) (c) | Vesting Dates (d) | Transition Awards (Note 5) (e) |
|---|---|---|---|---|
| Crane | 28 Jan. 2013 | 67,593 | (1) | 91,378 |
| | 27 Jan. 2014 | 112,749 | (1) | |
| Thayer | 12 Mar. 2012 | 6,758 | (2) | |
| | 28 Jan. 2013 | 16,506 | (1) | 24,473(6) |
| | 28 Jan. 2013 | 30,000 | 28 Jan. 2018 | |
| | 27 Jan. 2014 | 30,568 | (1)(3) | |
| Cornew | 01 Jul. 2010 | 10,000 | 01 Jul. 2015 | |
| | 28 Jan. 2013 | 19,813 | (1)(4) | 27,667(7) |
| | 28 Jan. 2013 | 30,000 | 28 Jan. 2018 | |
| | 27 Jan. 2014 | 34,644 | (1) | |
| O'Brien | 28 Jan. 2013 | 17,366 | (1) | 23,440 |
| | 27 Jan. 2014 | 28,939 | (1) | |
| Von Hoene Jr. | 28 Jan. 2013 | 15,071 | (1) | 20,288 |
| | 22 Oct. 2013 | 20,000 | 21 Oct. 2018 | |
| | 27 Jan. 2014 | 25,205 | (1) | |

**Notes to Restricted Stock Table**

(1) *Restricted stock unit awards vest in one-third increments on the date of the next three January committee meetings. Unvested awards earn additional units through automatic dividend reinvestment, and the resulting dividend units will vest and settle on the vesting date along with the underlying tranche of the original award.*

(2) *Represents the remaining balance of an award made to Mr. Thayer under the Constellation Energy Group Inc. Long Term Incentive Plan. At the time of the merger, the total award was converted to the right to receive 0.93 shares of Exelon common stock. The first third of the award vested on February 24, 2013; the second third vested on February 24, 2014 and the remainder vested on February 24, 2015. The unvested balance continues to earn additional units through automatic dividend reinvestment and the resulting dividend units will vest and settle on the vesting date along with the remaining underlying tranche of the original award.*

(3) *Mr. Thayer's original restricted stock unit grant of 27,900 shares made on January 27, 2014 was increased with the award of 1,600 additional units as of July 1, 2014 that have the same vesting schedule as the original grant.*

(4) *Mr. Cornew's original restricted stock unit grant of 24,100 shares made on January 28, 2013 was increased with the award of 3,600 additional units on May 28, 2013 that have the same vesting schedule as the original grant.*

(5) *Represents transition award shares that vested on January 26, 2015 based on averaging the results of the 2013 and 2014 performance periods, which resulted in a payout of 115.28% of target.*

(6) *Mr. Thayer's original transition award of 28,900 shares made on January 28, 2013 was increased effective July 1, 2014 to 33,600 shares and pro-rated so that 21,299 units would vest on January 26, 2015 with the second two-thirds of the original award.*

(7) *Mr. Cornew's original transition award of 27,667 shares made on January 28, 2013 was increased with the award of 4,762 additional units on May 28, 2013 of which 1,095 vested in January 2014 with the first third of the original award and 3,667 vested on January 26, 2015 with the second two-thirds of the original award.*

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# Executive Compensation Data

## *Option Exercises and Stock Vested*

| Name (a) | Option Awards: Number of Shares Acquired on Exercise (#) (b) | Option Awards: Value Realized on Exercise ($) (c) | Stock Awards (Note 1): Number of Shares Acquired on Vesting (#) (d) | Stock Awards (Note 1): Value Realized on Vesting ($) (e) |
|---|---|---|---|---|
| Crane | — | $ — | 141,144 | $3,980,262 |
| Thayer (2) | — | — | 41,747 | 1,191,523 |
| Cornew | — | — | 38,350 | 1,081,443 |
| O'Brien | — | — | 44,064 | 1,242,605 |
| Von Hoene Jr. | — | — | 41,815 | 1,179,183 |

**Notes to Option Exercises and Stock Vested Table**

(1) *Share amounts are generally composed of the following tranches of prior awards that vested on January 27, 2014: the second third of the performance share unit grant made with respect to the three-year performance period ending December 31, 2012; the final third of the performance share unit grant made with respect to the three-year performance period ending December 31, 2011; the first third of the transition award share granted on January 28, 2013; and the first third of the restricted stock unit grant made on January 28, 2013. All of these awards were valued at $28.20 upon vesting.*

(2) *For Mr. Thayer, the number of shares acquired upon vesting includes 6,510 restricted shares from a legacy Constellation award made in 2012 which was converted to the right to receive Exelon shares. One-third of the award (including one-third of the shares acquired through dividend reinvestment) vested on February 24, 2014, and shares were valued at $30.39.*

## *Pension Benefits*

Exelon sponsors the Exelon Corporation Retirement Program, a traditional defined benefit pension plan that covers certain management employees who commenced employment prior to January 1, 2001 and certain collective bargaining unit employees. The Exelon Corporation Retirement Program includes the Service Annuity System ("SAS"), which is the legacy ComEd pension plan. Effective January 1, 2001, Exelon also established two cash balance defined benefit pension plans in order to both reduce future retirement benefit costs and provide an option that is portable as the company anticipated a work force that was more mobile than the traditional utility workforce. The cash balance defined benefit pension plans cover management employees and certain collective bargaining unit employees hired on or after such date, as well as certain management employees hired prior to such date who elected to participate in a cash balance plan. Legacy Constellation employees participate in the Pension Plan of Constellation Energy Group, Inc. ("Constellation Pension Plan"). The Constellation Pension Plan includes a traditional pension formula referred to as the Enhanced Traditional Plan ("ETP") and a Pension Equity Plan ("PEP"). Employees hired before January 1, 2000 participate in the ETP. Employees hired on or after January 1, 2000 and employees hired before that date who elected to do so participate in the PEP. Each of these plans is intended to be tax-qualified under Section 401(a) of the Internal Revenue Code. An employee can participate in only one of the qualified pension plans.

For NEOs participating in the SAS, the annuity benefit payable at normal retirement age is equal to the sum of 1.25% of the participant's earnings as of December 25, 1994, reduced by a portion of the participant's Social Security benefit as of that date, plus 1.6% of the participant's highest average annual pay, multiplied by the participant's years of credited service (up to a maximum of 40 years). Pension-eligible compensation for the SAS's Final Average Pay Formula includes base pay and annual incentive awards. Benefits under the SAS are vested after five years of service.

The "normal retirement age" under the SAS is 65. The plan also offers an early retirement benefit prior to age 65, which is payable if a participant retires after attainment of age 50 and completion of 10 years of service. The annual pension payable under the plan is determined as of the early retirement date, reduced by 2% for each year of payment before age 60 to age 58, then 3% for each year before age 58 to age 50. In addition, under the SAS, the early retirement benefit is supplemented prior to age 65 by a temporary payment equal to 80% of the participant's estimated monthly Social Security benefit. The supplemental benefit is partially offset by a reduction in the regular annuity benefit.

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# Executive Compensation Data

Under the cash balance pension plan, a notional account is established for each participant, and the account balance grows as a result of annual benefit credits and annual investment credits. (Employees who participated in the SAS prior to January 1, 2001 and elected to participate in the cash balance plan also have a frozen transferred benefit from the former plan, and received a "transition" credit based on their age, service and compensation at the time of transfer.) Beginning January 1, 2008, the annual benefit credit under the plan is 7% of base pay and annual incentive award and beginning January 1, 2013 for employees hired on or after such date, the annual benefit credit is equal to a percentage of base pay and annual incentive award which varies between 3% and 8%, based upon age. For the portion of the account balance accrued beginning January 1, 2008, the annual investment credit is the third segment spot rate of interest on long-term investment grade corporate bonds. The segment rate will be determined as of November of the year for which the cash balance account receives the investment credit. For the portion of the benefit accrued before January 1, 2008, pending Internal Revenue Service guidance, the annual investment credit is the greater of 4%, or the average of the annual rate of return of the S&P 500 Stock Index and the 30-year Treasury bond rate (the interest rate is determined in November of each year). For employees hired on or after January 1, 2013, the annual investment credit is the second segment spot rate of interest on long-term corporate bonds, determined as of November of the year for which the cash balance account receives the investment credit, subject to a minimum annual investment credit rate of 3.8% and a maximum annual investment credit rate of 7%. Benefits are vested after three years of service, and are payable in an annuity or a lump sum at any time following termination of employment. Apart from the benefit credits and vesting requirement, and as described above, years of service are not relevant to a determination of accrued benefits under the cash balance pension plans.

For NEOs who participate in the PEP, a lump sum benefit amount is computed based on covered earnings multiplied by a total credit percentage. Covered earnings are equal to the average of the highest three of the last five twelve-month periods' base pay plus short-term incentive. The total service credit percentage is equal to the sum of the credit percentages based on the following formula: 5% per year of service through age 39, 10% per year of service from age 40 to age 49, and 15% per year of service after age 49. No benefits are available under the PEP until a participant has at least three years of vesting service. Benefits payable under the PEP are paid as an annuity unless a participant elects a lump sum within 60 days after separation.

The Internal Revenue Code limits to $260,000 the individual 2014 annual compensation that may be taken into account under the tax-qualified retirement plan. As permitted by Employee Retirement Income Security Act, Exelon sponsors three supplemental executive retirement plans (or "SERPs") that allow the payment to a select group of management or highly-compensated individuals out of its general assets of any benefits calculated under provisions of the applicable qualified pension plan which may be above these limits. The SERPs offer a lump sum as an optional form of payment, which includes the value of the marital annuity, death benefits and other early retirement subsidies at a designated interest rate. The interest rate applicable for distributions to participants in the SAS in 2014 is 3.89%. For participants in the cash balance pension plan and the PEP, the lump sum is the value of the non-qualified account balance. The values of the lump sum amounts do not include the value of any pension benefits covered under the qualified pension plans, and the methods and assumptions used to determine the non-qualified lump sum amount are different from the assumptions used to generate the present values shown in the tables of benefits to be received upon retirement, termination due to death or disability, involuntary separation not related to a change in control, or upon a qualifying termination following a change in control which appear later in this proxy statement.

Under the terms of the SERPs, participants are provided the amount of benefits they would have received under the SAS, cash balance plan, ETP or PEP, as applicable, but for the application of the Internal Revenue Code limits. In addition, certain executives previously received grants of additional credited service under a SERP. In particular, in 1998, Mr. Crane received an additional 10 years of credited service through September 28, 2008, the date of his tenth anniversary, as part of his employment offer that provided one additional year of service credit for each year of employment to a maximum of 10 additional years.

As of January 1, 2004, Exelon does not grant additional years of credited service to executives under the SERP for any period in which services are not actually performed, except that up to two years of service credits may be provided under

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# Executive Compensation Data

severance or change in control agreements first entered into after such date, and performance-based grants or grants which make up for lost pension benefits from another employer may be (but have not been) provided. Service credits previously available under employment, change in control or severance agreements or arrangements (or any successor arrangements) are not affected by this policy.

The amount of the change in the pension value for each of the named executive officers is the amount included in the Summary Compensation Table above in the column headed "Change in Pension Value & Nonqualified Deferred Compensation Earnings." The present value of each NEO's accumulated pension benefit is shown in the following tables. The present value for cash balance and PEP participants is the account balance. The assumptions used in estimating the present values for SAS participants include the following: pension benefits are assumed to begin at each participant's earliest unreduced retirement age; the SERP lump sum amounts are determined using the rate of 5% for SAS participants at the assumed retirement age; the lump sum amounts are discounted from the assumed retirement date at the applicable discount rates of 4.80% as of December 31, 2013 and 3.94% as of December 31, 2014; and the applicable mortality tables. The applicable table as of December 31, 2013 is the IRS required mortality table for the 2014 funding valuation for the Exelon Corporation qualified pension plans. The applicable mortality table as of December 31, 2014 was updated to a RP 2000-based table projected generationally using Exelon's best estimate of long-term mortality improvements. The December 31, 2014 mortality table is consistent with the mortality used in the Exelon December 31, 2014 pension disclosure.

| Name (a) | Plan Name (b) | Number of Years Credited Service (#) (c) | Present Value of Accumulated Benefit ($) (d) | Payments During Last Fiscal Year ($) (e) |
|---|---|---|---|---|
| Crane (1) | SAS | 16.26 | $ 890,036 | $ — |
| | SERP | 26.26 | 11,355,954 | — |
| Thayer | PEP | 12.00 | 204,000 | — |
| | SERP | 12.00 | 1,098,549 | — |
| Cornew | Cash Balance | 20.59 | 552,429 | — |
| | SERP | 20.59 | 689,617 | — |
| O'Brien | Cash Balance | 32.51 | 1,245,219 | — |
| | SERP | 32.51 | 1,442,235 | — |
| Von Hoene Jr. | Cash Balance | 12.93 | 308,711 | — |
| | SERP | 12.93 | 795,074 | — |

(1) *Based on discount rates prescribed by the SEC proxy disclosure guidelines, Mr. Crane's non-qualified SERP present value is $11,355,954. Based on lump sum plan rates for immediate distributions under the non-qualified plan, the comparable lump sum amount applicable for service through December 31, 2014 is $15,846,538. Note that, in any event, payments made upon termination may be delayed by six months in accordance with U.S. Treasury Department guidance.*

### *Deferred Compensation Programs*

Exelon offers deferred compensation plans to permit the deferral of certain cash compensation to facilitate tax and retirement planning and satisfaction of stock ownership requirements for executives and key managers. Exelon maintains non-qualified deferred compensation plans that are open to certain highly-compensated employees, including the NEOs.

The Exelon Deferred Compensation Plan is a non-qualified plan that permits legacy Exelon executives and key managers to defer receipt of base compensation and the company to credit related matching contributions that would have been contributed to the Exelon Corporation Employee Savings Plan (the company's tax-qualified 401(k) plan) but for the applicable limits under the Internal Revenue Code (the "Code"). The Constellation Deferred Compensation Plan is a non-qualified plan that permits legacy Constellation executives to defer receipt of base compensation and the company to credit related matching contributions that would have been contributed to the Exelon Corporation Employee Savings Plan. The Deferred Compensation Plans permit participants to defer taxation of a portion of their income. The Exelon Deferred Compensation Plan benefits the company by deferring the payment of a portion of its compensation expense, thus preserving cash.

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The Exelon Employee Savings Plan is intended to be tax-qualified under Sections 401(a) and 401(k) of the Code. The Constellation Energy Group Employee Savings Plan was merged into Exelon's Employee Savings Plan as of July 1, 2014. Exelon maintains the Employee Savings Plan to attract and retain qualified employees, including the NEOs, and to encourage employees to save some percentage of their cash compensation for their eventual retirement. The Employee Savings Plan permits employees to do so, and allows the company to make matching contributions in a relatively tax-efficient manner. The company maintains the excess matching feature of the Deferred Compensation Plans to enable key management employees to save for their eventual retirement to the extent they otherwise would have were it not for the limits established by the IRS.

The Stock Deferral Plan is a non-qualified plan that permitted legacy Exelon executives to defer performance share units prior to 2007.

The following table shows the amounts that NEOs have accumulated under both the Deferred Compensation Plans and the Stock Deferral Plan. The Exelon Deferred Compensation and Stock Deferral Plans were closed to new deferrals of base pay (other than excess Employee Savings Plan deferrals), annual incentive payments or performance shares awards in 2007, and participants were granted a one-time election to receive a distribution of their accumulated balance in each plan during 2007. Existing balances will continue to accrue dividends or other earnings until payout upon termination. Balances in the Deferred Compensation Plan will be settled in cash upon the termination event selected by the officer and will be distributed either in a lump sum, or in annual installments. Share balances in the Stock Deferral Plan continue to earn the same dividends that are available to all shareholders, which are reinvested as additional shares in the plan. Balances in the plan are distributed in shares of Exelon stock in a lump sum or installments upon termination of employment.

The Deferred Compensation Plans continue in effect for those officers who participate in the Employee Savings Plan and who reach their statutory contribution limit during the year. After this limit is reached, their elected payroll contributions and company matching contribution will be credited to their accounts in the Deferred Compensation Plans. The investment options under the Deferred Compensation Plans consist of a basket of mutual funds benchmarks substantially the same as those funds available through the Employee Savings Plan. Deferred amounts represent unfunded unsecured obligations of the company.

| Name (a) | Executive Contributions in 2014 ($) (Note 1) (b) | Registrant Contributions in 2014 ($) (Note 2) (c) | Aggregate Earnings in 2014 ($) (Note 3) (d) | Aggregate Withdrawals/ Distributions ($) (e) | Aggregate Balance at 12/31/14 ($) (Note 4) (f) |
|---|---|---|---|---|---|
| Crane | $ 102,500 | $ 35,540 | $ 69,111 | $ — | $ 909,139 |
| Thayer | — | — | — | — | — |
| Cornew | 27,788 | 19,452 | 22,147 | — | 199,929 |
| O'Brien (5) | 35,807 | 17,646 | 253,045 | — | 2,351,307 |
| Von Hoene Jr. | 23,835 | 16,685 | 35,070 | — | 295,827 |

(1) *The full amount shown for executive contributions is included in the base salary figures for each NEO shown above in the Summary Compensation Table.*

(2) *The full amount shown under registrant contributions is included in the company contributions to savings plans for each NEO shown above in the All Other Compensation Table.*

(3) *The amount shown under aggregate earnings reflects the NEO's gain or loss based upon the individual allocation of his notional account balance into the basket of mutual fund benchmarks. These gains or losses do not represent current income to the NEO and have not been included in any of the compensation tables shown above.*

(4) *For all NEOs the aggregate balance shown in column (f) above includes those amounts, both executive contributions and registrant contributions, that have been disclosed either as base salary as described in Note 1 or as company contributions under all other compensation as described in Note 2 for the current fiscal year ending December 31, 2014. For Mr. Crane, all executive and registrant contributions included in column (f) have previously been disclosed in Summary Compensation Tables. Mr. Thayer did not participate in the plan during 2014.*

(5) *For Mr. O'Brien the amounts shown in column (d) and column (f) also include the aggregate earnings and aggregate balance respectively of his Stock Deferral Plan account.*

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## *Potential Payments upon Termination or Change in Control*

### Change in control employment agreements and severance plan covering named executive officers

Exelon's change in control and severance benefits policies were initially adopted in January 2001 and harmonized the policies of Exelon's predecessor companies. In adopting the policies, the compensation committee considered the advice of a consultant who advised that the levels were consistent with competitive practice and reasonable. The Exelon benefits currently include multiples of change in control benefits ranging from two times base salary and annual bonus for corporate and subsidiary vice presidents to 2.99 times base salary and annual bonus for executive vice presidents, presidents of certain business units and select senior vice presidents other than the CEO. In 2003, the compensation committee reviewed the terms of the Senior Management Severance Plan and revised it to reduce the situations when an executive could terminate and claim severance benefits for "good reason," clarified the definition of "cause," and reduced non-change in control benefits for executives with less than two years of service. In December 2004, the compensation committee's consultant presented a report on competitive practice on executive severance. The competitive practices described in the report were generally comparable to the benefits provided under Exelon's severance policies. In discussing the compensation consultant's December 2007 annual report to the committee on compensation trends, the consultant commented that Exelon's change in control and severance policies were conservative, citing the use of double triggers, and that they remained competitive. In April 2009 the compensation committee adopted a policy that Exelon would not include excise tax gross-up payment provisions in senior executive employment, change in control, or severance plans, programs or agreements that are entered into, adopted or materially amended on or after April 2, 2009 (other than renewals of existing arrangements that are not materially amended or arrangements assumed pursuant to a corporate transaction).

Named executive officers have entered into individual change in control employment agreements or are covered by the change in control provisions of the Senior Management Severance Plan, which generally protect such executives' position and compensation levels for two years after a change in control of Exelon. The individual agreements are initially effective for a period of two years, and provide for a one-year extension each year thereafter until cancellation or termination of employment. The plan does not have a specific term.

During the 24-month period following a change in control, or, with respect to an executive with an individual agreement, during the 18-month period following another significant corporate transaction affecting the executive's business unit in which Exelon shareholders retain between 60% and $66\frac{2}{3}$% control (a significant acquisition), if a named executive officer resigns for good reason or if the executive's employment is terminated by Exelon other than for cause or disability, the executive is entitled to the following:

- the executive's annual incentive and performance share unit awards for the year in which termination occurs;
- severance payments equal to 2.99 (or 2.0 if the executive does not have an individual agreement) times the sum of (1) the executive's base salary plus (2) the higher of the executive's target annual incentive for the year of termination or the executive's average annual incentive award payments for the two years preceding the termination, but not more than the annual incentive for the year of termination based on actual performance before the application of negative discretion;
- a benefit equal to the amount payable under the SERP determined as if (1) the SERP benefit were fully vested, (2) the executive had 2.99 additional years of age and years of service (2.0 years for executives who first entered into such agreements after 2003 or do not have such agreements) and (3) the severance pay constituted covered compensation for purposes of the SERP;
- a benefit equal to the actuarial equivalent present value of any non-vested accrued benefit under Exelon's qualified defined benefit retirement plan;

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# Executive Compensation Data

- all previously-awarded stock options, performance shares or units, restricted stock, or restricted share units become fully vested, and the stock options remain exercisable until the earlier of the fifth anniversary of the executive's termination date or the option's expiration date;
- life, disability, accident, health and other welfare benefit coverage continues during the severance pay period on the same terms and conditions applicable to active employees, followed by retiree health coverage if the executive has attained at least age 50 and completed at least 10 years of service (or any lesser eligibility requirement then in effect for regular employees); and
- outplacement and financial planning services for at least 12 months.

The change in control benefits are also provided if the executive is terminated other than for cause or disability, or terminates for good reason (1) after a tender offer or proxy contest commences, or after Exelon enters into an agreement which, if consummated, would cause a change in control, and within one year after such termination a change in control does occur, or (2) within two years after a sale or spin-off of the executive's business unit in contemplation of a change in control that actually occurs within 60 days after such sale or spin-off (a disaggregation) if the executive has an individual agreement.

A change in control under the individual change in control employment agreements and the Senior Management Severance Plan generally occurs:

- when any person acquires 20% of Exelon's voting securities;
- when the incumbent members of the Exelon board of directors (or new members nominated by a majority of incumbent directors) cease to constitute at least a majority of the members of the Exelon board of directors;
- upon consummation of a reorganization, merger or consolidation, or sale or other disposition of at least 50% of Exelon's operating assets (excluding a transaction where Exelon shareholders retain at least 60% of the voting power); or
- upon shareholder approval of a plan of complete liquidation or dissolution.

The term good reason under the individual change in control employment agreements generally includes any of the following occurring within two years after a change in control or disaggregation or within 18 months after a significant acquisition:

- a material reduction in salary, incentive compensation opportunity or aggregate benefits, unless such reduction is part of a policy, program or arrangement applicable to peer executives;
- failure of a successor to assume the agreement;
- a material breach of the agreement by Exelon; or
- any of the following, but only after a change in control or disaggregation: (1) a material adverse reduction in the executive's position, duties or responsibilities (other than a change in the position or level of officer to whom the executive reports or a change that is part of a policy, program or arrangement applicable to peer executives) or (2) a required relocation by more than 50 miles.

The term cause under the change in control employment agreements generally includes any of the following:

- refusal to perform or habitual neglect in the performance of duties or responsibilities or of specific directives of the officer to whom the executive reports which are not materially inconsistent with the scope and nature of the executive's duties and responsibilities;
- willful or reckless commission of acts or omissions which have resulted in or are likely to result in a material loss or material damage to the reputation of Exelon or any of its affiliates, or that compromise the safety of any employee;
- commission of a felony or any crime involving dishonesty or moral turpitude;
- material violation of the code of business conduct which would constitute grounds for immediate termination of employment, or of any statutory or common-law duty of loyalty; or
- any breach of the executive's restrictive covenants.

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Executives who entered into such change in control employment agreements prior to April 2, 2009 (and which have not been materially amended after such date) will be eligible to receive an additional payment to cover excise taxes imposed under Section 4999 of the Internal Revenue Code on excess parachute payments or under similar state or local law, but only if the amount of payments and benefits subject to these taxes exceeds 110% of the safe harbor amount that would not subject the employee to these excise taxes. If the amount does not exceed 110% of the safe harbor amount, then payments and benefits subject to these taxes would be reduced or eliminated to equal the safe harbor amount.

If a named executive officer resigns for good reason or is terminated by Exelon other than for cause or disability, in each case under circumstances not involving a change in control or similar provision described above, the named executive officer may be eligible for the following non-change in control benefits under the Exelon Corporation Senior Management Severance Plan:

- prorated payment of the executive's annual incentive and performance share unit awards for the year in which termination occurs;
- for a 15 to 24 month severance period, continued payment of an amount representing base salary and target annual incentive;
- a benefit equal to the amount payable under the SERP determined as if the severance payments were paid as ordinary base salary and annual incentive;
- during the severance period, continuation of health, basic life and other welfare benefits the executive was receiving immediately prior to the severance period on the same terms and conditions applicable to active employees, followed by retiree health coverage if the executive has attained at least age 50 and completed at least 10 years of service (or any lesser eligibility requirement then in effect for non-executive employees); and
- outplacement and financial planning services for twelve months.

Payments under individual agreements entered into after April 2, 2009 or the Senior Management Severance Plan are subject to reduction by Exelon to the extent necessary to avoid imposition of excise taxes imposed by Section 4999 of the Internal Revenue Code on excess parachute payments or under similar state or local law.

The term good reason under the Senior Management Severance Plan means either of the following:

- a material reduction of the executive's salary (or, with respect to a change in control, incentive compensation opportunity or aggregate benefits) unless such reduction is part of a policy, program or arrangement applicable to peer executives of Exelon or of the business unit that employs the executive; or
- a material adverse reduction in the executive's position or duties (other than a change in the position or level of officer to whom the executive reports) that is not applicable to peer executives of Exelon or of the executive's business unit, but excluding under the non-change in control provisions of the plan any change (1) resulting from a reorganization or realignment of all or a significant portion of the business, operations or senior management of Exelon or of the executive's business unit or (2) that generally places the executive in substantially the same level of responsibility.

With respect to a change in control, the term good reason under the plan also includes a required relocation of more than 50 miles.

The term cause under the Senior Management Severance Plan has the same meaning as the definition of such term under the individual change in control employment agreements.

Benefits under the change in control employment agreements and the Senior Management Severance Plan are subject to termination upon an executive's violation of his or her restrictive covenants, and incentive payments under the agreements and the plan may be subject to the recoupment policy adopted by the board of directors.

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# Executive Compensation Data

## Estimated Value of Benefits to be Received Upon Retirement

The following table shows the estimated value of payments and other benefits to be conferred upon the NEOs assuming they retired as of December 31, 2014. These payments and benefits are in addition to the present value of the accumulated benefits from each NEO's qualified and non-qualified pension plans shown in the tables within the Pension Benefit section and the aggregate balance due to each NEO that is shown in the tables within the Nonqualified Deferred Compensation section.

| Name (a) | Cash Payment ($) (Note 1) (b) | Value of Unvested Equity Awards ($) (Note 2) (c) | Total Value of All Payments and Benefits ($) (Note 3) (d) |
|---|---|---|---|
| Crane | $ 1,554,000 | $ 26,741,000 | $ 28,295,000 |
| Thayer | — | — | — |
| Cornew | — | — | — |
| O'Brien | 850,000 | 587,000 | 1,437,000 |
| Von Hoene Jr. | 651,000 | 6,066,000 | 6,717,000 |

**Notes to Benefits to be Received Upon Retirement Table**

(1) *Under the terms of the 2014 Annual Incentive Plan (AIP), a pro-rated actual incentive award is payable upon retirement assuming an individual performance multiplier (IPM) of 100% and based on the number of days worked during the year of retirement. The amount above represents the executive's 2014 annual incentive payout (after company/business unit performance was determined) before applying the IPM, if applicable.*

(2) *The Value of Unvested Equity Awards includes the following:*

a. *the 'spread' on all unvested stock options that would vest upon termination of employment. The 'spread' is based on Exelon's closing stock price on December 31, 2014 of $37.08. At that stock price, all unvested stock options are "underwater" (or out of the money). Under the LTIP, if a holder has attained age 50 with 10 or more years of service (or deemed service), any unvested stock options will vest upon termination of employment because the holder has satisfied the definition of retirement under the LTIP;*

b. *the value of the executive's unvested performance share units. The amount above includes the number of unvested shares earned for the 2012 PSU awards, as applicable, as well as the unvested shares earned for the second tranche of the transition award, as applicable. It is assumed the 2013 and 2014 performance share units are earned at target. The value of the shares is based on Exelon's closing stock price on December 31, 2014 of $37.08; and*

c. *the accelerated portion of the executives' restricted stock award that, per the applicable award agreement, would vest upon retirement. The value of the shares is based on Exelon's closing stock price on December 31, 2014 of $37.08.*

(3) *The estimate of total payments and benefits is based on a December 31, 2014 retirement date.*

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# Executive Compensation Data

## Estimated Value of Benefits to be Received Upon Termination due to Death or Disability

The following table shows the estimated value of payments and other benefits to be conferred upon the NEOs assuming their employment is terminated due to death or disability as of December 31, 2014. These payments and benefits are in addition to the present value of the accumulated benefits from the NEO's qualified and non-qualified pension plans shown in the tables within the Pension Benefit section and the aggregate balance due to each NEO that is shown in tables within the Nonqualified Deferred Compensation section.

| Name (a) | Cash Payment ($) (Note 1) (b) | Value of Unvested Equity Awards ($) (Note 2) (c) | Total Value of All Payments and Benefits ($) (Note 3) (d) |
|---|---|---|---|
| Crane | $ 1,554,000 | $ 26,741,000 | $ 28,295,000 |
| Thayer | 738,000 | 8,752,000 | 9,490,000 |
| Cornew | 849,000 | 9,443,000 | 10,292,000 |
| O'Brien | 850,000 | 6,999,000 | 7,849,000 |
| Von Hoene Jr. | 651,000 | 6,808,000 | 7,459,000 |

**Notes to Benefits to be Received Upon Termination due to Death or Disability Table**

(1) *Under the terms of the 2014 AIP, a pro-rated actual incentive award is payable upon death or disability assuming an IPM of 100% and based on the number of days worked during the year of termination. The amount above represents the executives' 2014 annual incentive payout (after company/business unit performance was determined) before applying the IPM, if applicable.*

(2) *The Value of Unvested Equity Awards includes the following:*

a. *the 'spread' on all unvested stock options that would vest upon termination of employment. The 'spread' is based on Exelon's closing stock price on December 31, 2014 of $37.08. At that stock price, all unvested stock options are "underwater" (or out of the money). Under the LTIP, if a holder terminates employment due to death or disability, the holder's stock options will vest upon termination of employment;*

b. *the value of the executive's unvested performance share units. The amount above includes the number of unvested shares earned for 2012 PSU awards, as applicable, as well as the unvested earned shares for the second tranche of the transition award, as applicable. It is assumed the 2013 and 2014 performance share units are earned at target. The value of the shares is based on Exelon's closing stock price on December 31, 2014 of $37.08; and*

c. *the accelerated portion of the executives' restricted stock award that, per the applicable award agreement, would vest upon death or disability. The value of the shares is based on Exelon's closing stock price on December 31, 2014 of $37.08.*

(3) *The estimate of total payments and benefits is based on a December 31, 2014 termination due to death or disability.*

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## Estimated Value of Benefits to be Received Upon Involuntary Separation Not Related to a Change in Control

The following table shows the estimated value of payments and other benefits to be conferred upon the NEOs assuming they were terminated as of December 31, 2014 under the terms of the Amended and Restated Senior Management Severance Plan. These payments and benefits are in addition to the present value of the accumulated benefits from the NEO's qualified and non-qualified pension plans shown in the tables within the Pension Benefit section and the aggregate balance due to each NEO that is shown in the tables within the Nonqualified Deferred Compensation section.

| Name (a) | Cash Payment ($) (Note 1) (b) | Retirement Benefit Enhance-Ment ($) (Note 2) (c) | Value of Unvested Equity Awards ($) (Note 3) (d) | Health and Welfare Benefit Continuation ($) (Note 4) (e) | Perquisites And Other Benefits ($) (Note 5) (f) | Total Value of All Payments and Benefits ($) (Note 6) (g) |
|---|---|---|---|---|---|---|
| Crane | $ 6,954,000 | $ 4,066,000 | $ 26,741,000 | $ 91,000 | $ 40,000 | $ 37,892,000 |
| Thayer | 3,663,000 | 326,000 | 8,068,000 | 26,000 | 40,000 | 12,123,000 |
| Cornew | 4,129,000 | 230,000 | 8,722,000 | 38,000 | 40,000 | 13,159,000 |
| O'Brien | 3,835,000 | 209,000 | 6,999,000 | 55,000 | 40,000 | 11,138,000 |
| Von Hoene Jr. | 3,389,000 | 192,000 | 6,243,000 | 43,000 | 40,000 | 9,907,000 |

**Notes to Benefits to be Received Upon Involuntary Separation Not Related to a CIC Table**

(1) *Represents the estimated severance benefit equal to 2 times the sum of the executive's (i) current base salary and (ii) the target annual incentive for the year of termination. In addition, under Section 4.2 of the Senior Management Severance Plan, a pro-rated annual incentive award is payable upon involuntary separation or qualifying voluntary separation based on the days worked during the year of termination and assuming the NEO's IPM is 100% pursuant to the terms in the 2014 AIP. The amount above represents the executives' 2014 annual incentive payout (after company/business unit performance was determined) before applying the IPM, if applicable.*

(2) *Represents the estimated retirement benefit enhancement that consists of a one-time lump sum payment based on the actuarial present value of a benefit under the non-qualified pension plan assuming that the severance pay period was taken into account for purposes of vesting, and the severance pay constituted covered compensation for purposes of the non-qualified pension plan.*

(3) *The Value of Unvested Equity Awards includes the following:*

a. *the 'spread' on all unvested stock options that would vest upon termination of employment. The 'spread' is based on Exelon's closing stock price on December 31, 2014 of $37.08. At that stock price, all unvested stock options are "underwater" (or out of the money). Under the LTIP, if a holder has attained age 50 with 10 or more years of service (or deemed service), any unvested stock options will vest upon termination of employment because the holder has satisfied the definition of retirement under the LTIP;*

b. *the value of the executive's unvested performance share units. The amount above includes the number of unvested shares earned for the 2012 PSU awards, as applicable, as well as the unvested shares earned for the second tranche of the transition award. It is assumed the 2013 and 2014 performance share units are earned at target. The value of the shares is based on Exelon's closing stock price on December 31, 2014 of $37.08; and*

c. *the accelerated portion of the executives' restricted stock award that, per the applicable award agreement, would vest upon an involuntary separation not related to a change in control. The value of the shares is based on Exelon's closing stock price on December 31, 2014 of $37.08.*

(4) *Estimated costs of healthcare, life insurance, and long-term disability coverage which continue during the severance period.*

(5) *Estimated costs of outplacement and financial planning services for up to 12 months for all NEOs.*

(6) *The estimate of total payments and benefits is based on a December 31, 2014 termination date. The executives are participants in the Senior Management Severance Plan and severance benefits are determined pursuant to Section 4 of the Severance Plan.*

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# Executive Compensation Data

## Estimated Value of Benefits to be Received Upon a Qualifying Termination following a Change in Control

The following table shows the estimated value of payments and other benefits to be conferred upon the NEOs assuming they were terminated upon a qualifying change in control as of December 31, 2014. The company has entered into Change in Control agreements with Messrs. Crane, Cornew, O'Brien, and Von Hoene. These payments and benefits are in addition to the present value of accumulated benefits from the NEO's qualified and non-qualified pension plans shown in the tables within the Pension Benefit section and the aggregate balance due to each NEO that is shown in tables within the Nonqualified Deferred Compensation section.

| Name (a) | Cash Payment ($) (Note 1) (b) | Retirement Benefit Enhance-ment ($) (Note 2) (c) | Value of Unvested Equity Awards ($) (Note 3) (d) | Health and Welfare Benefit Continuation ($) (Note 4) (e) | Perquisites and Other Benefits ($) (Note 5) (f) | Modified Gross-up Payment ($) (Note 6) (g) | Scaleback ($) (Note 6) (h) | Total Value of All Payments and Benefits ($) (Note 7) (i) |
|---|---|---|---|---|---|---|---|---|
| Crane | $ 9,584,000 | $ 5,209,000 | $ 26,741,000 | $ 136,000 | $ 40,000 | $ 5,670,000 | Not required | $ 47,360,000 |
| Thayer | 5,086,000 | 326,000 | 8,752,000 | 39,000 | 40,000 | Not Required | $ (2,665,000) | 11,578,000 |
| Cornew | 5,724,000 | 343,000 | 9,443,000 | 56,000 | 40,000 | 5,880,000 | Not required | 21,486,000 |
| O'Brien | 5,390,000 | 218,000 | 6,999,000 | 82,000 | 40,000 | 4,280,000 | Not required | 17,009,000 |
| Von Hoene Jr. | 4,727,000 | 287,000 | 6,808,000 | 64,000 | 40,000 | Not Required | Not required | 11,926,000 |

**Notes to Benefits to be Received Upon a Qualifying Termination following a CIC Table**

(1) *Represents the estimated cash severance benefit equal to 2.99 times the sum of the executive's (i) current base salary and (ii) Severance Incentive. Also, this amount includes an additional payment for Mr. O'Brien of $35,000.*

*Under Section 4.1(a)(ii) of the CIC Employment Agreement, the executive's target incentive award is payable upon termination. The amounts above represent the executives' 2014 target annual incentive with the exception of Mr. Thayer. Under Section 5.1(a)(i) of the Senior Management Severance Plan, the executive is entitled to his or her annual incentive for the applicable performance period. For Mr. Thayer, the amount above represents his 2014 actual annual incentive payout (after company/business unit performance was determined) before applying his IPM, if applicable. Pursuant to the 2014 AIP, a pro-rated annual incentive award is payable, assuming the IPM is 100%.*

(2) *Represents the estimated retirement benefit enhancement that consists of a one-time lump sum payment based on the actuarial present value of a benefit under the non-qualified pension plan assuming that the severance pay period was taken into account for purposes of vesting, and the severance pay constituted covered compensation for purposes of the non-qualified pension plan.*

(3) *The Value of Unvested Equity Awards includes the following:*

a. *the 'spread' on all unvested stock options that would vest upon termination of employment. The 'spread' is based on Exelon's closing stock price on December 31, 2014 of $37.08. At that stock price, all unvested stock options are underwater (or out of the money);*

b. *the value of the executives' unvested performance share units. Pursuant to Section 4.1(c) of the CIC Employment Agreement and Section 5.1(c) of the Senior Management Severance Plan, all of the shares will vest upon termination at the actual level earned and awarded. The amount above includes the number of unvested shares earned for the 2012 PSU awards, as applicable, as well as the unvested shares earned for the second tranche of the transition award. It is assumed that the 2013 and 2014 performance share units are earned at target. The value of the shares is based on Exelon's closing stock price on December 31, 2014 of $37.08; and*

c. *the value of the executives' restricted stock that, pursuant to Section 4.1(d) of the CIC Employment Agreement or the terms of the award, would vest upon a qualifying termination following a change in control. The value of the shares is based on Exelon's closing stock price on December 31, 2014 of $37.08.*

(4) *Estimated costs of healthcare, life insurance and long-term disability coverage which continue during the severance period.*

(5) *Estimated costs of outplacement and financial planning services for up to 12 months for all NEOs.*

(6) *In 2009, the compensation committee adopted a policy that no future employment or severance agreements will provide for an excise tax gross-up payment. The Senior Management Severance Plan as amended and restated on January 1, 2009 and CIC Employment Agreements that become effective after April 2009 will reduce the executive's parachute payments to his or her safe harbor amount in order to avoid the excise tax imposed under Section 4999 of the Internal Revenue Code. Messrs. Crane, Cornew, O'Brien and Von Hoene have grandfathered CIC Employment Agreements, which still entitle these NEOs to an excise tax gross-up payment only if the present value of his parachute payments exceed his safe harbor amount by more than 10%. If the present value of their parachute payments do not exceed the amount permitted by the IRS by more than 10%, their payments are reduced to their safe harbor.*

(7) *The estimate of total payments and benefits is based on a December 31, 2014 termination date. The company has entered into change in control employment agreement with all of the executives except for Mr. Thayer who is a participant in the Senior Management Severance Plan and severance benefits are determined pursuant to Section 5 of the Senior Management Severance Plan.*

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# Vote on Performance Measures Included in Exelon Corporation's 2011 Long-Term Incentive Plan

## PROPOSAL 4: THE REAPPROVAL OF THE PERFORMANCE MEASURES INCLUDED IN EXELON CORPORATION'S 2011 LONG-TERM INCENTIVE PLAN

The Exelon board of directors is recommending shareholder approval of the material terms of the performance measures used for performance-based awards granted under the Exelon Corporation 2011 Long-Term Incentive Plan (the "2011 Plan"), in accordance with Section 162(m) of the Internal Revenue Code of 1986, as amended (the "Code"). The 2011 Plan, including the material terms of the performance measures under the plan, was approved by our shareholders at Exelon's 2010 annual meeting. Shareholders are being asked to reapprove the performance measures under the 2011 Plan so that certain compensation paid under the 2011 Plan may qualify as performance-based compensation under Section 162(m) of the Code ("Section 162(m)"). Shareholders are not being asked to approve an increase in the number of shares available under the 2011 Plan or an amendment to any provision of the Plan.

Under the 2011 Plan, various equity-based awards may be made to eligible participants, as described in further detail below. The 2011 Plan allows for the grant of performance-based compensation. The grant, vesting, crediting and/or payment of performance-based compensation, if any, will be based or conditioned on the achievement of objective performance measures established in writing by the compensation and leadership development committee of our board of directors.

Section 162(m) limits the deduction for federal income tax purposes of compensation for the CEO and the three other highest compensated officers (other than the CFO) (collectively, the "covered employee officers") to $1 million per year, unless such compensation qualifies as "performance-based compensation" under Section 162(m). Various requirements must be satisfied in order for compensation paid to the covered employee officers to qualify as performance-based compensation within the meaning of Section 162(m). One such requirement is that the compensation must be paid based upon the attainment of performance measures established by a committee of board members meeting the definition of "outside director" used for purposes of Section 162(m). The measures established by such a committee, which in our case would be the compensation and leadership development committee (the "committee"), must be based upon performance measures, the material terms of which are approved by shareholders. The material terms of the performance measures must be disclosed to and reapproved by shareholders every five years.

We are accordingly requesting the shareholders to reapprove the material terms of the performance measures for the 2011 Plan in accordance with Section 162(m).

The following is a description of the material terms of the performance measures and certain other material terms of the 2011 Plan. This description is qualified in its entirety by reference to the 2011 Plan, a copy of which has been included as Appendix A to this proxy statement.

**Material Terms of the Performance Measures**

*Participants*. Officers and other key management employees of Exelon and its subsidiaries (approximately 3,300) are eligible to participate in the 2011 Plan.

*Award Limits*. No 2011 Plan participant may be granted awards under the 2011 Plan during any calendar year that, in the aggregate, may be settled by delivery of more than 2,000,000 shares of Exelon common stock. With respect to awards that are valued on the basis of the fair market value of Exelon common stock and that may be settled in cash (in whole or part), no individual may be paid in any calendar year cash amounts exceeding the greater of the fair market value of the number of shares of Exelon common stock set forth in the preceding sentence either at the date of grant or at the date of settlement. With respect to awards that are not valued on the basis of the fair market value of the Exelon common stock, the

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# Vote on Performance Measures Included in Exelon Corporation's 2011 Long-Term Incentive Plan

compensation payable in any calendar year (in cash or shares) may not have an aggregate fair market value in excess of $5 million. The share figures described above are subject to adjustment in the event of a stock split, stock dividend, recapitalization, reorganization, merger, spin-off or other similar change or event.

*Performance Measures.* Under the 2011 Plan, the vesting or payment of performance share awards and performance unit awards will be subject to the satisfaction of certain performance goals. The performance goals applicable to a particular award will be determined by the committee at the time of grant. To the extent an award is intended to qualify for the performance-based exemption from the $1 million deduction limit under Section 162(m), as described below, the performance goals will be one or more of the following, each of which may be based on absolute standards or peer industry group comparatives and may be applied at various organizational levels (*e.g.*, corporate, business unit, or division): (1) cumulative shareholder value added, (2) customer satisfaction, (3) revenue, (4) primary or fully-diluted earnings per share of Exelon common stock, (5) net income, (6) total shareholder return, (7) earnings before interest and taxes, (8) cash flow, including operating cash flows, free cash flow, discounted cash flow return on investment and cash flow in excess of cost of capital, or any combination thereof, (9) economic value added, (10) return on equity, (11) return on capital, (12) return on assets (13) net operating profits after taxes, (14) stock price increase, (15) return on sales, (16) debt to equity ratio, (17) payout ratio, (18) asset turnover, (19) ratio of share price to book value of shares, (20) price/earnings ratio, (21) employee satisfaction, (22) diversity, (23) market share, (24) operating income, (25) pre-tax income, (26) safety, (27) diversification of business opportunities, (28) expense ratios, (29) total expenditures, (30) completion of key projects, (31) dividend payout as percentage of net income, (32) earnings before interest, taxes, depreciation and amortization, or (33) any individual performance objective which is measured solely in terms of quantitative targets related to Exelon, any subsidiary or Exelon's or subsidiary's business. Such individual performance measures related to Exelon, a subsidiary or their respective businesses may include: (a) production-related factors such as generating capacity factor, performance against the INPO index, generating equivalent availability, heat rates and production cost, (b) transmission and distribution-related factors such as customer satisfaction, reliability (based on outage frequency and duration), and cost, (c) customer service-related factors such as customer satisfaction, service levels and responsiveness and bad debt collections or losses, and (d) relative performance against other similar companies in targeted areas. The measures may be weighted differently for holders of awards based on their management level and the extent to which their responsibilities are primarily corporate or business unit-related, and may be based in whole or in part on the performance of Exelon, a subsidiary, division and/or other operational unit under one or more of such measures.

**Summary Description of the 2011 Plan**

Under the 2011 Plan, Exelon may grant nonqualified stock options, incentive stock options, stock appreciation rights ("SARs"), restricted stock, restricted stock units, performance shares and performance units (collectively, the "Awards"). The purposes of the 2011 Plan are to align the interests of Exelon's shareholders and the recipients of awards under the 2011 Plan by increasing the proprietary interest of recipients in Exelon's growth and success, to advance the interests of Exelon by attracting and retaining officers and other key management employees and to motivate such persons to act in the long-term best interests of Exelon and its shareholders.

*Administration.* The 2011 Plan is administered by the committee or another committee designated by the Board. Except with respect to (1) grants to officers of Exelon who are subject to Section 16 of the Exchange Act or whose title with Exelon is "executive vice president" or higher or decisions concerning the timing, pricing or amount of an award to such officer or other person and (2) grants to a person whose compensation is likely to be subject to the $1 million deduction limit under Section 162(m), the committee may delegate some or all of its power and authority to administer the 2011 Plan to the Chief Executive Officer or other executive officer of Exelon. However, the maximum number of shares of Exelon common stock subject to options and SARs that may be granted by Exelon's Chief Executive Officer in any single year may not exceed 1,200,000 in the aggregate or 40,000 with respect to any individual participant. The maximum number of shares of Exelon common stock subject to restricted stock awards, restricted stock units awards, performance share awards and performance

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# Vote on Performance Measures Included in Exelon Corporation's 2011 Long-Term Incentive Plan

unit awards that may be granted by Exelon's Chief Executive Officer in any single year may not exceed 600,000 in the aggregate or 20,000 with respect to any individual participant. The share figures described above are subject to adjustment as described below.

*Available Shares.* The 2011 Plan initially reserved 5,000,000 shares of our common stock for the issuance of Awards, increased by the number of shares which at that time were available for future grant under Exelon's prior equity compensation plan, and subject to adjustment as described below. The number of available shares is reduced by the sum of the aggregate number of shares of Exelon common stock which become subject to outstanding Awards. To the extent that shares of Exelon common stock subject to an outstanding Award granted under either the 2011 Plan or Exelon's prior equity compensation plan are not issued or delivered by reason of the expiration, termination, cancellation or forfeiture of such award (excluding shares of Exelon common stock subject to an option cancelled upon settlement of a related tandem SAR or subject to a tandem SAR cancelled upon exercise of a related option), then such shares of Exelon common stock will again be available under the 2011 Plan.

The maximum number of shares of Exelon common stock initially available under the 2011 Plan for restricted stock awards, restricted stock unit awards, performance share awards and performance unit awards was 5,000,000, increased by the number of shares of Exelon common stock which at that time were available for future grant under Exelon's prior equity compensation plan.

The last reported sale price of a share of the Exelon's common stock on March 10, 2015 was $XX.

*Adjustment.* In the event of any stock split, stock dividend, recapitalization, merger, consolidation, combination, exchange of shares, liquidation, spin-off or other similar change in capitalization or event, or any distribution to stockholders (other than a regular cash dividend), the number and class of securities available for all awards under the 2011 Plan, the maximum number of shares with respect to which awards may be granted during any year to any one person, the maximum number of shares subject to awards that may be granted during any year by the Chief Executive Officer, and the number and class of securities subject to each outstanding award and the purchase price per security will be appropriately adjusted by the Committee.

*Termination and Amendment.* The Committee may amend or terminate the 2011 Plan or any Award agreement at any time, subject to any requirement of shareholder approval required by applicable law, rule or regulation, including Section 162(m) of the Code, and provided that no amendment may be made that impairs the rights of a holder of an outstanding award without the consent of such holder. Unless sooner terminated by the Committee, the 2011 Plan will terminate on January 1, 2021.

**Tax Matters**

In general, a participant will not recognize taxable income at the time a stock option is granted. Upon exercise of a non-qualified stock option, a participant will recognize compensation, taxable as ordinary income, equal to the excess of the fair market value of the shares of common stock purchased over their exercise price. In the case of "incentive stock options," within the meaning of Section 422 of the Code, a participant will not recognize ordinary income at the time of exercise (except for purposes of the alternative minimum tax), and if the participant observes certain holding period requirements, then when the shares are sold, the entire gain over the exercise price will be taxable at capital gains rates. A participant has no taxable income at the time stock appreciation rights are granted, but will recognize compensation taxable as ordinary income upon exercise in an amount equal to the fair market value of any shares of common stock delivered and the amount of any cash paid by Exelon. A participant who is granted shares of restricted stock, including shares subject to performance conditions, generally will not recognize taxable income at the time the restricted stock is granted, but will recognize compensation taxable as ordinary income at the time the restrictions lapse in an amount equal to the excess of the fair market value of the shares of common stock at such time over the amount, if any, paid for such shares. However, a participant instead may elect to recognize compensation taxable as ordinary income on the date the restricted stock is

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granted in an amount equal to the fair market value of the shares on that date. The taxation of other stock based Awards will depend on how such Awards are structured. Generally, a participant who is granted an Award of restricted stock units, performance shares or performance units will not recognize taxable income at the time such Award is granted. When the restrictions applicable to the Award lapse, and the shares of common stock subject to the restricted stock units, performance shares or performance units are transferred (or any amount of cash is paid) to the participant, the participant will recognize compensation taxable as ordinary income in an amount equal to the fair market value of the shares of common stock on the date of transfer and the amount of any cash paid by Exelon.

Subject to the Section 162(m) deduction limitation described above, Exelon may deduct, as a compensation expense, the amount of ordinary income recognized by a participant in connection with the 2011 Plan at the time such ordinary income is recognized by that participant.

**New Plan Benefits**

The number of performance-based awards granted under the 2011 Plan in any year is subject to the committee's discretion and is, therefore, not determinable.

**The board of directors unanimously recommends a vote "FOR" reapproval of the performance measures included in Exelon Corporation's 2011 Long-Term Incentive Plan.**

# Vote on Management Proposal Regarding Proxy Access

## PROPOSAL 5: THE EXELON BOARD'S PROPOSAL REGARDING PROXY ACCESS

The board of directors believes that "proxy access"—the ability of shareholders to include shareholder-nominated candidates in the company's proxy materials for annual meetings of shareholders—would also enhance shareholder ability to participate in director elections while potentially enhancing board accountability and responsiveness. However, the board believes that it is important to structure proxy access to minimize the potential for abuse by investors who lack a meaningful long-term interest in Exelon or who wish to promote special interests that are not aligned with the interests of other shareholders. The board also believes that proxy access should be structured to minimize disruption of board functions and effectiveness.

This proxy statement includes a proxy access proposal from the New York City Comptroller on behalf of several New York City pension funds. The board of directors of Exelon evaluated the proposal and considered the composition of Exelon's shareholders, Exelon's governance practices, and other factors. Exelon also sought input on the subject of proxy access from shareholders holding over 39 percent of Exelon's outstanding common stock. As discussed in more detail below, shareholders' opinions about proxy access are mixed: some shareholders support proxy access consistent with the SEC rule adopted in 2010 (which was subsequently struck down by a federal court); some shareholders support proxy access but expressed concerns about the potential for shareholder abuse of proxy access and disruption of board functions; other shareholders were opposed to proxy access in any form; and many shareholders expressed support for having an opportunity to consider alternatives.

Accordingly, the board believes that shareholders should have the opportunity to consider alternative proxy access proposals. The board is therefore presenting for shareholder vote both its own proposal and the New York City Comptroller's proposal for proxy access, which include different standards regarding the appropriate qualifications for shareholders to use proxy access, the number of directors who may be nominated, and other important matters.

Both the board's proposal and the shareholder proposal are advisory in nature, and each constitutes a recommendation to the board. Shareholders may vote FOR, AGAINST or ABSTAIN on each separate proposal. The board will take into consideration the shareholder vote for and against each proposal and will also seek additional shareholder input on proxy access through Exelon's long-standing program of outreach to its shareholders. If a majority of shares represented at the meeting in person or by proxy and eligible to vote are voted in favor of either proxy access proposal, Exelon intends to bring to a vote at the 2016 annual meeting of shareholders a binding proposal for amendments to Exelon's bylaws to implement some form of proxy access. Abstentions on a proposal will have the same effect as votes against that proposal.

In considering alternative proxy access proposals, the board of directors encourages shareholders to consider proxy access in the context of other provisions already included in Exelon's articles of incorporation, bylaws, Corporate Governance Principles and other practices that promote engagement with shareholders and accountability of management and the board to Exelon's investors. These include:

- Annual election of directors;
- Majority vote standard for the election of directors;
- A process for shareholders to submit nominations of director candidates for consideration by the corporate governance committee;
- A process for shareholders to make nominations of director candidates at Exelon's annual meeting, subject to conditions set forth in the bylaws;
- A process for shareholders to present proposals to be included in the proxy statement, subject to conditions set forth in the bylaws and the rules and regulations of the Securities and Exchange Commission;

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# Vote on Management Proposal Regarding Proxy Access

- No supermajority voting requirements in Exelon's articles of incorporation or bylaws;
- No "poison pill";
- All but two of the directors are independent;
- The chairman of the board and the lead director are separate from the chief executive officer;
- An active shareholder engagement program through which the board seeks input from shareholders at least annually and often twice a year;
- Annual advisory vote on executive compensation; and
- A defined process for shareholders to communicate with the board.

The proposal for proxy access recommended by the board of directors is printed in its entirety in the resolutions below. In summary, the proposal recommended by the board, if implemented, would allow any shareholder or group of up to 20 shareholders holding both investment and voting rights with respect to at least 5 percent of Exelon's outstanding common stock continuously for at least 3 years to nominate up to 20 percent of the Exelon directors to be elected (2 directors on Exelon's current board of 13 directors) at the annual meeting of shareholders. A shareholder or group of shareholders making a nomination through proxy access would be required to submit information, including information to verify that the nominee(s) will meet the objective standards for independence as determined by the New York Stock Exchange rules and the objective standards for director independence in Exelon's Corporate Governance Principles. Shareholders are encouraged to read the full text of the Exelon proposal for additional details. The Exelon proposal follows:

**RESOLVED,** that the shareholders of Exelon Corporation (the "Company") ask the board of directors to adopt, and present for shareholder approval at the 2016 annual meeting of shareholders, a "proxy access" bylaw, which shall require the Company to include in the proxy statement and the related proxy card prepared for the annual meeting of shareholders the name and other required information of any person nominated for election to the board by an individual beneficial owner or group of up to 20 beneficial owners of shares (the "Nominator"), subject to the conditions established below.

(a) The number of shareholder-nominated candidates appearing in the Company's proxy materials shall not exceed 20 percent of the directors to be elected at the annual meeting. A Nominator and members of a Nominator group shall not be permitted to participate in another group that is making a nomination of other nominees through proxy access at the same meeting. A shareholder making (or joining in making) a nomination of directors through procedures other than proxy access shall not be allowed to make (or join in making) a nomination at the same meeting through proxy access.

(b) The Nominator shall have owned of record or beneficially (with full voting and investment rights and the full economic interest, including the opportunity for profit and risk of loss) at least 5 percent of the Company's outstanding common stock continuously for at least 3 years before submitting the nomination and shall continue to hold such ownership through the date of the meeting at which the nominees are proposed for election.

(c) The Nominator shall give the Company, within the time period to be specified in its bylaws and in the form and manner required by the bylaws, all information required by the bylaws and any Securities and Exchange Commission rules about: (1) each nominee, including each nominee's consent to being named in the proxy materials and to serving as director if elected, information regarding any compensation or indemnification arrangement with any entity or person other than the Company that the nominee may have in respect of his or her proposed service or action as a director, information regarding any arrangement or understanding with any person or entity that the nominee may have as to how he or she, if elected as a director, will act or vote on any issue or question, and information requested by the Company to confirm that each nominee will meet the standards for independence set forth in New York Stock Exchange rules and the Company's Corporate Governance Principles

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and information requested by the Company to verify that the election of each nominee will not violate any applicable laws or regulations; and (2) the Nominator, including proof it owns the required shares for the required holding period.

(d) The Nominator shall certify (jointly and severally for each member of a group) that: (1) it will assume liability stemming from any legal or regulatory violation arising out of the Nominator's communications with the Company shareholders, including information included in the Company's proxy materials at the request of the Nominator; (2) it will comply with all applicable laws and regulations if it uses soliciting material other than the Company's proxy materials; (3) the Company shares beneficially owned by the Nominator were acquired in the ordinary course of business and not with the intent or objective to change or influence control of the Company and are not being held with the purpose or effect of changing control of the Company or to gain a number of seats on the board of directors that exceeds the maximum number of nominees that shareholders may nominate pursuant to the proxy access process; and (4) the Nominator intends to hold the required shares through the date of the annual meeting and for at least one year thereafter if the Nominator's nominee(s) are elected.

(e) The Nominator may submit with the nomination, for inclusion in the Company's proxy statement, a statement not exceeding 500 words (including disclosure of the nominee's personal and biographical information required by SEC rules) in support of each nominee; provided that the Company shall not be required to include in its proxy statement any material submitted by the Nominator that the Company reasonably believes to be materially false and misleading.

**FURTHER RESOLVED,** that the shareholders request that amendments to the bylaws include: (1) additional procedures and standards for determining the amount, nature and duration of stock ownership; (2) procedures for promptly resolving disputes over whether notice of a nomination was timely and whether the information provided by the Nominator satisfies the bylaws and applicable federal regulations; (3) the priority to be given to multiple nominations exceeding the limit to the number of directors that may be nominated by shareholders at the annual meeting; and (4) such other procedures, standards and requirements as the board determines are necessary and appropriate to carry out the intention of these resolutions.

**Exelon's board of directors unanimously recommends a vote "FOR" this proposal for the following reasons:**

- **The Exelon board of directors believes that the right to nominate up to 20 percent of the board (2 seats on a board of 13 directors) to serve on the Exelon board is a reasonable limit that will afford shareholders a meaningful opportunity to obtain board representation without excessive disruption of the balance of skill, experience and diversity of the board that would more likely result from the addition of a larger number of directors through a proxy access process.**

Exelon already has a process for shareholders to make recommendations to the corporate governance committee for nominees for election to the board. The corporate governance committee has an important role in considering the effectiveness of the board and in identifying nominees who possess a combination of skills, professional experience and diversity of background necessary to oversee Exelon's complex business. The corporate governance committee also considers whether a candidate would contribute to an effective and well-rounded and diverse board that operates openly and collaboratively and represents the best interests of all shareholders, and not just those with a special interest. The corporate governance committee's process for considering nominees for director and the matters it considers are described above at page 23 under the heading "Director Nomination Process." Although Exelon recognizes the value of proxy access, the board also recognizes that nominees proposed through proxy access are not subject to any evaluation or screening by the board's corporate governance committee. Proxy access could therefore result in loss of important skills, experience and diversity on the board of directors.

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# Vote on Management Proposal Regarding Proxy Access

Several of the shareholders Exelon consulted expressed support for limiting the maximum number of directors who could be nominated through proxy access to 20 percent of the board, so that there could be enough shareholder-selected nominees to have a meaningful effect on the board without excessive disruption of the board's continuity and operations and the balance of the skills, experience and diversity of the board.

The board believes that the criteria in the board's proposal allowing nominations of directors representing up to 20 percent of the board strikes the right balance between affording proxy access to long-term shareholders while not being overly disruptive to board functions and effectiveness that might adversely affect Exelon's financial and operational performance.

- **The Exelon board believes its proposed 5 percent ownership requirement provides a reasonable balance between the desire to provide meaningful rights to shareholders and the need to reduce the potential for abuse of proxy access by shareholders who may seek to advance special interests that may not be in the interest of all shareholders.**

Several shareholders with whom Exelon discussed the subject expressed support for a minimum ownership requirement of 5 percent, although others expressed a preference for a 3 percent ownership standard. In this regard, the board notes that Exelon currently has 5 shareholders who own more than 5 percent of Exelon's stock, and 13 shareholders who hold at least 1 percent of Exelon's stock; those shareholders hold, in the aggregate, over 45 percent of Exelon's stock and could act individually or with others in that group with little effort to meet a 5 percent eligibility requirement for proxy access. A lower share ownership requirement would provide greater opportunities for shareholders with narrowly defined special interests and short-term goals to promote their special interests and disrupt the operations of Exelon's board and its business strategy. Small shareholders with legitimate concerns shared by other shareholders will have the opportunity to form a group to meet the required minimum holdings of Exelon shares.

- **The board's proposal requires a nominating shareholder or shareholder group to hold full voting and investment rights and the full economic interest, including the opportunity for profit and risk of loss, with respect to the required holdings of Exelon common stock continuously for at least 3 years.**

The board believes that proxy access should be structured to require a sustained commitment to Exelon in terms of the shareholder's ownership holding period, consistent with Exelon's focus on managing the business for the long term. The board's proxy access proposal will preclude the use of Exelon stock sold short in meeting the ownership requirements for proxy access. If a proxy access proposal is approved, Exelon also intends to propose standards in the definitive amendment to the bylaws for the treatment of borrowed shares in the share ownership requirements.

- **Exelon's board believes that a shareholder group making a nomination pursuant to proxy access should consist of no more than 20 shareholders. This will limit the administrative burden and expense that could otherwise be imposed upon Exelon in verifying the nature and duration of holdings of a large number of shareholders participating in a nomination.**

Exelon believes that this is a reasonable limitation that will reduce administrative costs for Exelon and help reduce the risk of abuse of proxy access rights. Exelon has 48 shareholders who collectively hold over 62 percent of Exelon's common stock. These shareholders could easily act alone or form a group of 20 or fewer shareholders to establish the requisite 5 percent ownership requirement. Other holders of Exelon's common stock who have legitimate concerns about the composition of the board could easily join with any one or more of the larger holders of Exelon stock to form a group of 20 or fewer shareholders with the requisite 5 percent ownership. In the absence of a reasonable limitation on the number of shareholders in a group, Exelon could be required to make burdensome inquiries into the nature and duration of the share ownership of a large number of individuals participating in a nomination in order to verify their qualifications to make the nomination.

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# Vote on Management Proposal Regarding Proxy Access

- **The Exelon board believes that shareholders using proxy access to nominate directors should be required to provide information confirming that each nominee, if elected, will qualify as an independent director under the New York Stock Exchange rules and Exelon's Corporate Governance Principles and that the election of each nominee will not violate applicable laws.**

The board's proposal includes a requirement that information regarding director independence be provided with respect to each nominee so it can be made available to shareholders when they cast their votes in the election of directors. Absent this requirement, shareholders will have information about the independence of Exelon's nominees under the relevant independence standards but may not receive complete information about shareholder nominees.

Federal antitrust laws prohibit the service of a person on the boards of directors of companies that may be considered competitors. Nominees for director must be screened for compliance with these laws, which may require extensive analysis of the companies' revenues attributable to specific geographic markets in which they do business.

- **The Exelon board believes that shareholders using proxy access to nominate directors should not be allowed to participate in another nomination pursuant to proxy access for the same election or engage in a proxy contest at the same meeting to seek the election of a greater number of nominees than the shareholder would be permitted to nominate through proxy access.**

The board's proposal provides that a shareholder participating in a nomination of directors through procedures other than proxy access will not be allowed to participate in a nomination at the same meeting through proxy access. Proxy access is intended to allow shareholders to nominate directors without the expense of a proxy solicitation. A shareholder who uses proxy access and engages in a proxy solicitation at the same time incurs the expense that proxy access is intended to avoid, and diminishes the opportunities of other shareholders to make use of proxy access.

The nominating shareholder and members of a nominating group will not be permitted to join in another group that is making a nomination of other nominees through proxy access. This restriction is needed to prevent the use of the same shares to meet the minimum shareholding requirements for multiple nominations through proxy access.

- **The Exelon proposal for proxy access represents the framework that the board believes would be most beneficial to all Exelon shareholders without excessive disruption in the functions and effectiveness of the board.**

**The board of directors unanimously recommends a vote "FOR" the management proposal regarding proxy access.**

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# Vote on Shareholder Proposal Regarding Proxy Access

## PROPOSAL 6: A SHAREHOLDER PROPOSAL REGARDING PROXY ACCESS

The Comptroller of the City of New York, as the custodian and a trustee of the New York City Employees' Retirement System, the New York City Fire Department Pension Fund, the New York City Teachers' Retirement System, and the New York City Police Pension Fund, and custodian of the New York City Board of Education Retirement System (the "Systems"), beneficial owners of 1,727,092 shares of stock which have been held continuously for more than one year, submitted the following proposal and supporting statement:

"RESOLVED: Shareholders of Exelon Corporation (the "Company") ask the board of directors (the "Board") to adopt, and present for shareholder approval, a 'proxy access' bylaw. Such a bylaw shall require the Company to include in proxy materials prepared for a shareholder meeting at which directors are to be elected the name, Disclosure and Statement (as defined herein) of any person nominated for election to the board by a shareholder or group (the "Nominator") that meets the criteria established below. The Company shall allow shareholders to vote on such nominee on the Company's proxy card. The number of shareholder-nominated candidates appearing in proxy materials shall not exceed one quarter of the directors then serving. This bylaw, which shall supplement existing rights under Company bylaws, should provide that a Nominator must:

a) have beneficially owned 3% or more of the Company's outstanding common stock continuously for at least three years before submitting the nomination;

b) give the Company, within the time period identified in its bylaws, written notice of the information required by the bylaws and any Securities and Exchange Commission rules about (i) the nominee, including consent to being named in the proxy materials and to serving as director if elected; and (ii) the Nominator, including proof it owns the required shares (the "Disclosure"); and

c) certify that (i) it will assume liability stemming from any legal or regulatory violation arising out of the Nominator's communications with the Company shareholders, including the Disclosure and Statement; (ii) it will comply with all applicable laws and regulations if it uses soliciting material other than the Company's proxy materials; and

d) to the best of its knowledge, the required shares were acquired in the ordinary course of business and not to change or influence control at the Company.

The Nominator may submit with the Disclosure a statement not exceeding 500 words in support of the nominee (the "Statement"). The Board shall adopt procedures for promptly resolving disputes over whether notice of a nomination was timely, whether the Disclosure and Statement satisfy the bylaw and applicable federal regulations, and the priority to be given to multiple nominations exceeding the one-quarter limit.

SUPPORTING STATEMENT

We believe proxy access is a fundamental shareholder right that will make directors more accountable and contribute to increased shareholder value. The CFA Institute's 2014 assessment of pertinent academic studies and the use of proxy access in other markets similarly concluded that proxy access:

- Would "benefit both the markets and corporate boardrooms, with little cost or disruption.
- Has the potential to raise overall US market capitalization by up to $140.3 billion if adopted market-wide. (http://www.cfapubs.org/doi/pdf/10.2469/ccb.v2014.n9.l)

The proposed bylaw terms enjoy strong investor support -votes for similar shareholder proposals averaged 55% from 2012 through September 2014- and similar bylaws have been adopted by companies of various sizes across industries, including Chesapeake Energy, Hewlett-Packard, Western Union and Verizon. We urge shareholders to vote FOR this proposal."

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# Vote on Shareholder Proposal Regarding Proxy Access

## Exelon's Statement in Opposition

This shareholder proposal is based, in part, on a controversial "proxy access" rule adopted by the Securities and Exchange Commission in 2010, which was subsequently struck down by a federal court because the SEC did not adequately analyze the costs to U.S. companies of managing contested board elections and did not back up its claim that the rule would improve shareholder value and board performance. The Exelon board of directors believes that proxy access, if properly structured, would enhance shareholder ability to participate in director elections while potentially enhancing board accountability and responsiveness. However, the board believes that this shareholder proposal is not properly structured to (1) minimize the potential for abuse by investors who lack a meaningful long-term interest in Exelon or who wish to promote special interests that are not aligned with the interests of other shareholders and (2) minimize disruption of board functions and effectiveness.

Exelon sought input on the subject of this proposal from shareholders holding over 39 percent of Exelon's outstanding common stock. Exelon found that shareholders' opinions about proxy access are mixed: some shareholders support proxy access consistent with the SEC rule adopted in 2010; some shareholders supported proxy access but expressed concerns about the potential for shareholder abuse of proxy access and disruption of board functions; other shareholders were opposed to proxy access in any form; and many shareholders expressed support for having an opportunity to consider alternatives to this proposal.

**The Exelon board of directors recommends a vote AGAINST this proposal for the following reasons:**

- **The board of directors believes that the right to nominate up to 25 percent of the board (3 seats on a board of 13 directors) each year to serve on the Exelon board will result in excessive disruption of the balance of skill, experience and diversity of the board and reduce the board's effectiveness and adversely affect Exelon's financial and operational performance.**

The board's corporate governance committee has an important role in considering the effectiveness of the board and in identifying nominees who possess a combination of skills, professional experience and diversity of background necessary to oversee Exelon's complex business. The corporate governance committee also considers whether a candidate would contribute to an effective and well-rounded and diverse board that operates openly and collaboratively and represents the best interests of all shareholders, and not just those with a special interest. Nominees proposed through proxy access are not subject to any evaluation or screening by the corporate governance committee regarding the nominee's ability to contribute to an effective, well-rounded and diverse board that operates openly and collaboratively in the best interest of all shareholders. Proxy access could therefore result in loss of important skills, experience and diversity on the board of directors.

Several of the shareholders Exelon consulted expressed support for limiting the maximum number of directors who could be nominated through proxy access to 20 percent of the board (2 seats on a board of 13), so that there could be enough shareholder-selected nominees to have a meaningful effect on the board without excessive disruption of the board's continuity and operations and the balance of the skills, experience and diversity of the board. The board shares the views expressed by some shareholders that proxy access without reasonable limits could detract from the effectiveness of the board and thus adversely affect Exelon's financial and operational performance.

- **The Exelon board believes the proposed 3 percent ownership requirement in the shareholder proposal fails to provide a reasonable balance between the desire to provide meaningful rights to shareholders and the need to reduce the potential for abuse of proxy access by shareholders who may seek to advance special interests that may not be in the interest of all shareholders.**

A 3 percent share ownership requirement would provide greater opportunities for shareholders with narrowly defined special interests and short-term goals to promote their special interests and disrupt the operations of Exelon's board and its business strategy. For this reason, some shareholders who provided input to Exelon expressed a preference for a higher share ownership requirement. A higher share ownership requirement would reduce this risk without significantly detracting from the goals of proxy access.

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# Vote on Shareholder Proposal Regarding Proxy Access

- **The shareholder proposal does not require a nominating shareholder or shareholder group to hold full voting and investment rights and the full economic interest, including the opportunity for profit and risk of loss, over the requisite amount of Exelon stock continuously for the required holding period, does not preclude the use of Exelon stock sold short in meeting the ownership requirements for proxy access, and fails to address the treatment of borrowed shares in the share ownership requirements.**

Absent a requirement for the nominating shareholder to retain voting power and investment power with respect to the shares one must own to establish eligibility to nominate a director, a shareholder could have a net short position on Exelon stock and still be entitled to use proxy access to make a nomination. The board believes that proxy access should be structured to require a sustained commitment to Exelon in terms of the shareholder's ownership interest and holding period, consistent with Exelon's focus on managing the business for the long term. Although the shareholder proposal purports to be patterned after the SEC rule adopted in 2010, the proposal fails to include these important protections that would be included in the SEC rule had it not been invalidated by a court ruling.

- **The shareholder proposal does not require nominating shareholders to retain ownership of their shares through the meeting date or disclose their intentions regarding continued ownership of shares following the meeting date.**

A nominating shareholder could sell all or any portion of the required shares prior to the meeting date, potentially creating misalignment between the interests of the nominating shareholder and other shareholders. Shareholders should be aware of the nominating shareholder's intentions regarding continued ownership following the meeting in order to gauge the nominating shareholder's interest in the company.

- **The shareholder proposal places no limit on the number of shareholders who can assemble as a group to establish the share ownership required to make a nomination pursuant to proxy access, which could result in excessive administrative burden and expense for Exelon.**

Exelon believes that a reasonable limitation should be established to reduce administrative costs for Exelon and help reduce the risk of abuse of proxy access rights. In the absence of a reasonable limitation on the number of shareholders in a group, Exelon could be required to make burdensome and time-consuming inquiries into the nature and duration of the share ownership of a large number of individuals participating in a nomination in order to verify their required share ownership, which could impede the exercise of proxy access rights by other shareholders.

- **The shareholder proposal fails to address several important considerations relevant to proxy access.**

Among other things, the shareholder proposal fails to address requirements for independence of shareholder nominees, the potential for a shareholder to participate simultaneously in more than one proxy access nomination, and the potential for a shareholder to nominate directors through proxy access while simultaneously engaging in a proxy contest to elect more directors than permitted under proxy access.

**The board of directors unanimously recommends a vote "AGAINST" this proposal.**

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# Communication with the Board of Directors

## PROCESS FOR SHAREHOLDER COMMUNICATIONS WITH THE BOARD

Shareholders and other interested persons can communicate with the Lead Director or with the independent directors as a group by writing to them, c/o Bruce G. Wilson, Senior Vice President, Deputy General Counsel and Corporate Secretary, Exelon Corporation, 10 South Dearborn Street, P.O. Box 805398, Chicago, Illinois 60680-5398. The board has instructed the Corporate Secretary to review communications initially and transmit a summary to the directors and to exclude from transmittal any communications that are commercial advertisements, other forms of solicitation, general shareholder service matters or individual service or billing complaints. Under the board policy, the Corporate Secretary will forward to the directors any communication raising substantial issues. All communications are available to the directors upon request. Shareholders may also report an ethics concern with the Exelon Ethics Hotline by calling 1-800-23-Ethic (1-800-233-8442). You may also report an ethics concern via the Internet at EthicsOffice@ExelonCorp.com.

## SHAREHOLDER PROPOSALS

If you want to submit a proposal for possible inclusion in next year's proxy statement, you must submit it in writing to the Corporate Secretary, Exelon Corporation, 10 South Dearborn Street, P.O. Box 805398, Chicago, Illinois 60680-5398. Exelon must receive your proposal on or before November 20, 2015. Exelon will consider only proposals meeting the requirements of the applicable rules of the Securities and Exchange Commission ("SEC"). Under our Bylaws, the proposal must also disclose fully all ownership interests the proponent has in Exelon and contain a representation as to whether the shareholder has any intention of delivering a proxy statement to the other shareholders of Exelon.

We strongly encourage any shareholder interested in submitting a proposal to contact our Corporate Secretary in advance of this deadline to discuss the proposal, and shareholders may want to consult knowledgeable counsel with regard to the detailed requirements of applicable securities laws. Submitting a shareholder proposal does not guarantee that we will include it in our proxy statement. Our corporate governance committee reviews all shareholder proposals and makes recommendations to the board for action on such proposals.

Additionally, under our Bylaws, for a shareholder to bring any matter before the 2016 annual meeting that is not included in the 2015 proxy statement, the shareholder's written notice must be received by the Corporate Secretary not less than 120 days prior to the first anniversary of the mailing date of this proxy statement, which will be November 20, 2015.

## DIRECTOR NOMINATIONS

A shareholder who wishes to recommend a candidate (including a self-nomination) to be considered by the Exelon corporate governance committee for nomination as a director must submit the recommendation in writing to the Chair of the Corporate Governance Committee, c/o Bruce G. Wilson, Senior Vice President, Deputy General Counsel and Corporate Secretary, Exelon Corporation, 10 South Dearborn Street, P.O. Box 805398, Chicago, Illinois 60680-5398. The corporate governance committee will consider all recommended candidates and self-nominees when making its recommendation to the full board of directors to nominate a slate of directors for election.

- **Nominations for 2015.** Under the Exelon Bylaws, the deadline has passed for a shareholder to nominate a candidate (or nominate himself or herself) for election to the board of directors at the 2015 annual meeting.
- **Nominations for 2016.** To nominate a candidate for election as a director or to stand for election at the 2016 annual meeting, a shareholder must either submit a recommendation to the corporate governance committee or provide the

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# Communication with the Board of Directors

proper notice and the other information required by Exelon's Bylaws. The Bylaws currently require the following: (1) notice of the proposed nomination must be received by Exelon no later than November 20, 2015; (2) the notice must include information required under the Bylaws, including: (a) information about the nominating shareholder, (b) information about the candidate that would be required to be included in a proxy statement under the rules of the SEC, (c) a representation as to whether the shareholder intends to deliver a proxy statement to the other shareholders of Exelon, and (d) the signed consent of the candidate to serve as a director of Exelon, if elected. Exelon's Bylaws are amended from time to time. Please review the Bylaws on our website to determine if any changes to the nomination process or requirements have been made.

## AVAILABILITY OF CORPORATE DOCUMENTS

The Exelon Corporate Governance Principles, the Exelon Code of Business Conduct, the Exelon Amended and Restated Bylaws, and the charters for the audit, corporate governance, compensation and leadership development and other committees of the board of directors are available on the Exelon website at www.exeloncorp.com, on the corporate governance page under the Investors tab. Copies may be printed from the Exelon website and copies are available without charge to any shareholder who requests them by writing to Bruce G. Wilson, Senior Vice President, Deputy General Counsel and Corporate Secretary, Exelon Corporation, 10 South Dearborn Street, P.O. Box 805398, Chicago, Illinois 60680-5398. In addition, our Articles of Incorporation, Compensation Consultant Independence Policy, Political Contributions Guidelines, biographical information concerning each director, and all of our filings submitted to the SEC are available on our website. Access to this information is free of charge to any user with internet access. Information contained on our website is not part of this proxy statement.

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# Frequently Asked Questions

## Can I access the Notice of Annual Meeting and Proxy Statement and the 2014 Financial Report on the Internet?

As permitted by SEC rules, we are making this proxy statement and our annual report available to shareholders electronically via the internet at www.proxyvote.com. On March 19, 2015, we began mailing to our shareholders a notice containing instructions on how to access this proxy statement and our annual report and how to vote online. If you received that notice, you will not receive a printed copy of the proxy materials unless you request it by following the instructions for requesting such materials contained on the notice.

In addition, shareholders may request to receive proxy materials in printed form or electronically by email on an ongoing basis. Exelon encourages shareholders to take advantage of the availability of the proxy materials on the internet in order to save Exelon the cost of producing and mailing documents to you, reduce the amount of mail you receive and help preserve resources.

Shareholders of Record: If you vote on the internet at www.proxyvote.com, simply follow the prompts for enrolling in the electronic delivery service.

Beneficial Owners: You also may be able to receive copies of these documents electronically. Please check the information provided in the proxy materials sent to you by your bank, broker or other holder of record regarding the availability of this service.

## Do I need a ticket to attend the annual meeting?

You will need an admission ticket or proof of ownership to enter the annual meeting.

If you are a shareholder of record the bottom half of your proxy card will serve as your admission ticket.

If your shares are held in the name of a bank, broker, or other holder of record and you plan to attend the meeting, you must present proof of your ownership of Exelon stock as you enter the meeting, such as a bank or brokerage account statement. If you would rather have an admission ticket, you can obtain one in advance by mailing a written request, along with proof of your ownership of Exelon stock, to:

> Annual Meeting Admission Tickets c/o Bruce G. Wilson, Senior Vice President, Deputy General Counsel and Corporate Secretary, Exelon Corporation, 10 South Dearborn Street, P.O. Box 805398 Chicago, Illinois 60680-5398.

Shareholders also must present a form of personal photo identification in order to be admitted into the meeting.

**No cameras, audio or video recording equipment, similar electronic devices, large bags, briefcases or packages will be permitted into the meeting or adjacent areas. Cell phones and similar wireless communication devices will be permitted in the meeting only if turned off. All items brought into the meeting will be subject to search.**

## Who is entitled to vote at the annual meeting?

Holders of Exelon common stock as of 5:00 p.m. New York Time on March 10, 2015 are entitled to receive notice of the annual meeting and to vote their shares at the meeting. As of that date, there were XXX,XXX,XXX shares of common stock outstanding and entitled to vote. Each share of common stock is entitled to one vote on each matter properly brought before the meeting.

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# Frequently Asked Questions

## What is the difference between holding shares as a shareholder of record and as a beneficial owner?

If your shares are registered directly in your name with Exelon's transfer agent, Wells Fargo Shareowner Services, you are the "shareholder of record" of those shares. This Notice of Annual Meeting and Proxy Statement and accompanying documents have been provided directly to you by Exelon.

If your shares are held in a stock brokerage account or by a bank or other holder of record, you are considered the "beneficial owner" of those shares. This Notice of Annual Meeting and Proxy Statement and the accompanying documents have been forwarded to you by your broker, bank or other holder of record. As the beneficial owner, you have the right to direct your broker, bank or other holder of record how to vote your shares by using the voting instruction card or by following their instructions for voting by telephone or on the Internet.

## How do I vote?

Your vote is important. We encourage you to vote promptly. Internet and telephone voting are available through 11:59 p.m. Eastern Time on April 27, 2015. You may vote in the following ways:

- **By Internet.** If you have internet access, you may vote by internet. You will need the control number included on your proxy card or voting instruction form ("VIF"), as applicable. You may vote in a secure manner at www.proxyvote.com 24 hours a day. You will be able to confirm that the system has properly recorded your votes, and you do not need to return your proxy card or VIF.
- **By Telephone.** If you are located in the United States or Canada, you can vote by calling the toll-free telephone number (1-800-690-6903) and following the recorded instructions. You will need the control number included on your Notice Regarding the Availability of Proxy Materials, proxy card or VIF, as applicable. You may vote by telephone 24 hours a day. The telephone voting system has easy-to-follow instructions and allows you to confirm that the system has properly recorded your votes. If you vote by telephone, you do not need to return your proxy card or your VIF.
- **By Mail.** If you are a holder of record and received a full paper set of materials, you can vote by marking, dating and signing your proxy card and returning it by mail in the postage-paid envelope provided. If you are a beneficial holder of shares held of record by a bank or broker or other street name, please complete and mail the VIF provided by the holder of record.
- **At the Annual Meeting.** If you are a shareholder of record and attend the annual meeting in person, you may use a ballot provided at the meeting to cast your vote. If you are a beneficial owner, you will need to have a legal proxy from your broker, bank or other holder of record in order to vote by ballot at the meeting.

## May I revoke a proxy?

Yes. You may revoke a proxy at any time before the proxy is exercised by filing with the Corporate Secretary a notice of revocation, or by submitting a later-dated proxy by mail, telephone or electronically through the Internet. You may also revoke your proxy by attending the annual meeting and voting in person.

## What is householding and how does it affect me?

Exelon has adopted a procedure approved by the SEC called "householding." Under this procedure, shareholders of record who have the same address and last name and do not participate in electronic delivery of proxy materials will receive only one copy of this Notice of Annual Meeting and Proxy Statement and the 2014 Annual Report, unless we are notified that one or more of these shareholders wishes to continue receiving individual copies. This procedure will reduce our printing costs and postage fees.

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# Frequently Asked Questions

## What are the voting requirements to elect the directors and to approve each of the proposals discussed in the Proxy Statement?

The presence of the holders of a majority of the outstanding shares of common stock entitled to vote at the annual meeting, in person or represented by proxy, is necessary to constitute a quorum.

**Election of Directors: Majority Vote Policy**
Under our Bylaws, directors must be elected by a majority of votes cast in uncontested elections. This means that the number of votes cast "for" a director nominee must exceed the number of votes cast "against" the nominee. In contested elections, the vote standard would be a plurality of votes cast.

Our Bylaws provide that, in an uncontested election, each director nominee must submit to the board before the annual meeting a letter of resignation that becomes effective only if the director fails to receive a majority of the votes cast at the annual meeting. The resignation of a director nominee who is not an incumbent director is automatically accepted by the board. The resignation of an incumbent director is tendered to the independent directors of the board for a determination of whether or not to accept the resignation. The board's decision and the basis for the decision would be disclosed within 90 days following the certification of the final vote results.

**Ratification of PricewaterhouseCoopers as Independent Auditor**
The appointment of PricewaterhouseCoopers LLP as Exelon Corporation's independent auditor requires an affirmative vote of a majority of shares of common stock represented at the annual meeting and entitled to vote thereon in order to be adopted.

**Executive Compensation**
The vote on executive compensation is advisory and is not binding on the company, the board of directors, or the compensation and leadership development committee in any way, as provided by law. Our board and the compensation and leadership development committee will review the results of the vote and input from shareholders and will take it into account in making a determination concerning executive compensation consistent with our record of shareowner engagement.

**Performance Measures included in 2011 Long-Term Incentive Plan**
The approval of the performance measures in the 2011 Long-Term Incentive Plan requires an affirmative vote of a majority of shares represented at the annual meeting and entitled to vote thereon.

**Management Proposal Regarding Proxy Access**
The adoption of the management proposal regarding proxy access requires an affirmative vote of a majority of shares represented at the annual meeting and entitled to vote thereon. Abstentions will have the same effect as a vote against the proposal.

**Shareholder Proposal Regarding Proxy Access**
The adoption of the shareholder proposal requires an affirmative vote of a majority of shares represented at the annual meeting and entitled to vote thereon. Abstentions will have the same effect as a vote against the proposal.

## How frequently will I have an opportunity to vote on executive compensation?

Every year. The Exelon board of directors has decided to hold the advisory vote on executive compensation annually until the next required vote on the frequency of shareholder votes on the compensation of executives.

## Could other matters be decided at the annual meeting?

At the date this proxy statement went to press, we did not know of any matters to be raised at the annual meeting other than those referred to in this proxy statement.

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# Frequently Asked Questions

### Who will count the votes?

Representatives of Broadridge Financial Communications and Exelon's Office of Corporate Governance will tabulate the votes and act as inspectors of the election.

### Where can I find the voting results?

We will report the voting results in a Form 8-K to be filed with the SEC within four business days following the end of our annual meeting.

### Who will pay for the cost of this proxy solicitation?

Exelon will pay the cost of soliciting proxies. Proxies may be solicited on our behalf by directors, officers or employees in person or by telephone, electronic transmission and facsimile transmission. We have hired Alliance Advisors, LLC to distribute and solicit proxies. We will pay Alliance Advisors, LLC a fee of $15,000 plus reasonable expenses for these services.

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# Appendix A

## EXELON CORPORATION'S 2011 LONG-TERM INCENTIVE PLAN (AS AMENDED EFFECTIVE DECEMBER 18, 2014)

### I. INTRODUCTION

1.1 Purposes. The purposes of the Exelon Corporation 2011 Long-Term Incentive Plan (this "Plan") are (i) to align the interests of the Company's stockholders and the recipients of awards under this Plan by increasing the proprietary interest of such recipients in the Company's growth and success, (ii) to advance the interests of the Company by attracting and retaining officers and other key management employees and (iii) to motivate such persons to act in the long-term best interests of the Company and its stockholders.

**1.2 Certain Definitions.**

"**Affiliate**" shall mean any Person (including a Subsidiary) that directly or indirectly controls, is controlled by, or is under common control with, the Company. 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.

"**Agreement**" shall mean the written agreement evidencing an award hereunder between the Company and the recipient of such award.

"**Beneficial Owner**" shall mean such term as defined in Rule 13d-3 under the Exchange Act.

"**Board**" shall mean the Board of Directors of the Company.

"**Cause**" shall mean (a) with respect to an employee whose entitlement to severance benefits upon termination of employment is governed by an individual change in control agreement, the meaning of such term specified in such agreement, (b) with respect to an employee whose entitlement to severance benefits upon termination of employment is governed by the Exelon Corporation Senior Management Severance Plan or any other executive severance plan, as in effect from time to time, the meaning of such term specified in such plan, or (c) with respect to any other employee, the meaning of such term specified in the Exelon Corporation Severance Benefit Plan, as amended from time to time, or any successor plan thereto, regardless of whether such employee is eligible to participate in such plan.

"**Change in Control**" shall have the meaning set forth in Section 5.8.

"**Code**" shall mean the Internal Revenue Code of 1986, as amended.

"**Committee**" shall mean the Committee designated by the Board, consisting of two or more members of the Board, each of whom may be (i) a "Non-Employee Director" within the meaning of Rule 16b-3 under the Exchange Act, (ii) an "outside director" within the meaning of Section 162(m) of the Code and (iii) "independent" within the meaning of the rules of the New York Stock Exchange or, if the Common Stock is not listed on the New York Stock Exchange, within the meaning of the rules of the principal national stock exchange on which the Common Stock is then traded.

"**Common Stock**" shall mean the common stock, without par value, of the Company.

"**Company**" shall mean Exelon Corporation, a Pennsylvania corporation, or any successor thereto.

"**Company Plan**" shall have the meaning set forth in Section 5.8(b)(i).

"**Corporate Transaction**" shall have the meaning set forth in Section 5.8(a).

"**Disability**" shall have the meaning specified in any long term disability plan maintained by the Company in which the participant is eligible to participate; provided that a Disability shall not be deemed to have occurred until the Company has terminated such participant's employment in connection with such disability and the participant has commenced the

# Appendix A

receipt of long-term disability benefits under such plan. If an participant is not eligible to participate in a long-term disability plan maintained by the Company, then Disability shall mean a termination of such participant's employment by the Company due to the inability of such participant to perform the essential functions such participant's position, with or without reasonable accommodation, for a continuous period of at least twelve months, as determined solely by the Committee.

"**Exchange Act**" shall mean the Securities Exchange Act of 1934, as amended.

"**Fair Market Value**" shall mean the closing transaction price of a share of Common Stock as reported on the New York Stock Exchange on the date as of which such value is being determined or, if the Common Stock is not listed on the New York Stock Exchange, the closing transaction price of a share of Common Stock on the principal national stock exchange on which the Common Stock is traded on the date as of which such value is being determined or, if there shall be no reported transactions for such date, on the next preceding date for which transactions were reported; provided, however, that if the Common Stock is not listed on a national stock exchange or if Fair Market Value for any date cannot be so determined, Fair Market Value shall be determined by the Committee by whatever means or method as the Committee, in the good faith exercise of its discretion, shall at such time deem appropriate and in accordance with Section 409A of the Code.

"**Free-Standing SAR**" shall mean an SAR which is not granted in tandem with, or by reference to, an option, which entitles the holder thereof to receive, upon exercise, shares of Common Stock (which may be Restricted Stock), cash or a combination thereof with an aggregate value equal to the excess of the Fair Market Value of one share of Common Stock on the date of exercise over the base price of such SAR, multiplied by the number of such SARs which are exercised.

"**Good Reason**" shall mean (i) with respect to an employee whose entitlement to severance benefits upon termination of employment is governed by an individual change in control agreement, the meaning of such term specified in such agreement, or (ii) with respect to an employee whose entitlement to severance benefits upon termination of employment is governed by the Exelon Corporation Senior Management Severance Plan or any other executive severance plan, as in effect from time to time, the meaning of such term specified in such plan.

"**Incentive Stock Option**" shall mean an option to purchase shares of Common Stock that meets the requirements of Section 422 of the Code, or any successor provision, which is intended by the Committee to constitute an Incentive Stock Option.

"**Incumbent Board**" shall have the meaning set forth in Section 5.8(b)(ii).

"**Nonqualified Stock Option**" shall mean an option to purchase shares of Common Stock which is not an Incentive Stock Option.

"**Performance Measures**" shall mean the criteria and objectives, established by the Committee, which shall be satisfied or met (i) as a condition to the grant or exercisability of all or a portion of an option or SAR or (ii) during the applicable Restriction Period or Performance Period as a condition to the vesting of the holder's interest, in the case of a Restricted Stock Award, of the shares of Common Stock subject to such award, or, in the case of a Restricted Stock Unit Award or Performance Unit Award, to the holder's receipt of the shares of Common Stock subject to such award or of payment with respect to such award. To the extent necessary for an award to be qualified performance-based compensation under Section 162(m) of the Code and the regulations thereunder, such criteria and objectives shall include one or more of the following measures, each of which may be based on absolute standards or peer industry group comparatives and may be applied at various organizational levels (e.g., corporate, business unit, division): (1) cumulative shareholder value added (SVA), (2) customer satisfaction, (3) revenue, (4) primary or fully-diluted earnings per share of Common Stock, (5) net income, (6) total shareholder return, (7) earnings before interest taxes (EBIT), (8) cash flow, including operating cash flows, free cash flow, discounted cash flow return on investment and cash flow in excess of cost of capital, or any combination thereof, (9) economic value added, (10) return on equity,

# Appendix A

(11) return on capital, (12) return on assets, (13) net operating profits after taxes, (14) stock price increase, (15) return on sales, (16) debt to equity ratio, (17) payout ratio, (18) asset turnover, (19) ratio of share price to book value of shares, (20) price/earnings ratio, (21) employee satisfaction, (22) diversity, (23) market share, (24) operating income, (25) pre-tax income, (26) safety, (27) diversification of business opportunities, (28) expense ratios, (29) total expenditures, (30) completion of key projects, (31) dividend payout as percentage of net income, (32) earnings before interest, taxes, depreciation and amortization (EBITDA), or (33) any individual performance objective which is measured solely in terms of quantitative targets related to the Company, any Subsidiary or the Company's or Subsidiary's business. Such individual performance measures related to the Company, a Subsidiary or the Company's or Subsidiary's business may include: (A) production-related factors such as generating capacity factor, performance against the INPO index, generating equivalent availability, heat rates and production cost, (B) transmission and distribution-related factors such as customer satisfaction, reliability (based on outage frequency and duration), and cost, (C) customer service-related factors such as customer satisfaction, service levels and responsiveness and bad debt collections or losses, and (D) relative performance against other similar companies in targeted areas. The measures may be weighted differently for holders of awards based on their management level and the extent to which their responsibilities are primarily corporate or business unit-related, and may be based in whole or in part on the performance of the Company, a Subsidiary, division and/or other operational unit under one or more of such measures. In the sole discretion of the Committee, but subject to Section 162(m) of the Code, the Committee may amend or adjust the Performance Measures or other terms and conditions of an outstanding award in recognition of unusual or nonrecurring events affecting the Company or its financial statements or changes in law or accounting principles.

"**Performance Option**" shall mean an Incentive Stock Option or Nonqualified Stock Option, the grant of which or the exercisability of all or a portion of which is contingent upon the attainment of specified Performance Measures within a specified Performance Period.

"**Performance Period**" shall mean any period designated by the Committee during which (i) the Performance Measures applicable to an award shall be measured and (ii) the conditions to vesting applicable to an award shall remain in effect.

"**Performance Share Award**" shall mean a Restricted Stock Award or Restricted Stock Unit Award, the vesting of which is subject to the attainment of specified Performance Measures within a specified Performance Period.

"**Performance Unit**" shall mean a right to receive, contingent upon the attainment of specified Performance Measures within a specified Performance Period and the expiration of any applicable Restriction Period, a specified cash amount or, in lieu thereof, shares of Common Stock having a Fair Market Value equal to such cash amount.

"**Performance Unit Award**" shall mean an award of Performance Units under this Plan.

"**Person**" shall mean 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.

"**Plan**" shall have the meaning set forth in Section 1.1.

"**Prior Plan**" shall mean the Exelon Corporation 2006 Long-Term Incentive Plan, as amended.

"**Restricted Stock**" shall mean shares of Common Stock which are subject to a Restriction Period and which may, in addition thereto, be subject to the attainment of specified Performance Measures within a specified Performance Period.

"**Restricted Stock Award**" shall mean an award of Restricted Stock under this Plan.

"**Restricted Stock Unit**" shall mean a right to receive one share of Common Stock or, in lieu thereof, the Fair Market Value of such share of Common Stock in cash, which shall be contingent upon the expiration of a specified Restriction Period and which may, in addition thereto, be contingent upon the attainment of specified Performance Measures within a specified Performance Period.

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"**Restricted Stock Unit Award**" shall mean an award of Restricted Stock Units under this Plan.

"**Restriction Period**" shall mean any period designated by the Committee during which (i) the Common Stock subject to a Restricted Stock Award may not be sold, transferred, assigned, pledged, hypothecated or otherwise encumbered or disposed of, except as provided in this Plan or the Agreement relating to such award, or (ii) the conditions to vesting applicable to a Restricted Stock Unit Award shall remain in effect.

"**Restrictive Covenant**" shall have the meaning set forth in Section 2.3(g).

"**Retirement**" shall mean the retirement of a holder of an award from employment with the Company on or after attaining the minimum age specified for early or normal retirement in any then effective qualified defined benefit retirement plan of the Company in which such holder is a participant, provided that such holder has also attained age 50 and completed at least ten years of service with the Company and the Subsidiaries. For purposes of this definition, the holder's age and service shall be determined taking into account any deemed age or service awarded to the holder for benefit accrual purposes under any nonqualified defined benefit retirement plan of the Company in which the holder is a participant.

"**SAR**" shall mean a stock appreciation right, which may be a Free-Standing SAR or a Tandem SAR.

"**SEC Person**" shall mean any person (as such term is used in Rule 13d-5 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 (i) the Company or an Affiliate, or (ii) any employee benefit plan (or any related trust) of the Company or any of its Affiliates.

"**Stock Award**" shall mean a Restricted Stock Award or a Restricted Stock Unit Award, including any such award which is granted as a Performance Share Award.

"**Subsidiary**" shall mean any corporation, limited liability company, partnership, joint venture or similar entity in which the Company owns, directly or indirectly, an equity interest possessing more than 50% of the combined voting power of the total outstanding equity interests of such entity.

"**Tandem SAR**" shall mean an SAR which is granted in tandem with, or by reference to, an option (including a Nonqualified Stock Option granted prior to the date of grant of the SAR), which entitles the holder thereof to receive, upon exercise of such SAR and surrender for cancellation of all or a portion of such option, shares of Common Stock (which may be Restricted Stock), cash or a combination thereof with an aggregate value equal to the excess of the Fair Market Value of one share of Common Stock on the date of exercise over the base price of such SAR, multiplied by the number of shares of Common Stock subject to such option, or portion thereof, which is surrendered.

"**Tax Date**" shall have the meaning set forth in Section 5.5.

"**Ten Percent Holder**" shall have the meaning set forth in Section 2.1(a).

"**20% Owner**" shall have the meaning set forth in Section 5.8(b)(i).

"**Voting Securities**" shall mean with respect to a corporation, securities of such corporation that are entitled to vote generally in the election of directors of such corporation.

1.3 **Administration**. This Plan shall be administered by the Committee. Any one or a combination of the following awards may be made under this Plan to eligible persons: (i) options to purchase shares of Common Stock in the form of Incentive Stock Options or Nonqualified Stock Options (which may include Performance Options), (ii) SARs in the form of Tandem SARs or Free-Standing SARs, (iii) Stock Awards in the form of Restricted Stock or Restricted Stock Units (which may include Performance Share Awards) and (iv) Performance Units. The Committee shall, subject to the terms of this Plan, select eligible persons for participation in this Plan and determine the form, amount and timing of each award to such persons and, if applicable, the number of shares of Common Stock, the number of SARs, the number of Restricted Stock Units and the number of Performance Units subject to such an award, the exercise price or base price

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associated with the award, the time and conditions of exercise or settlement of the award and all other terms and conditions of the award, including, without limitation, the form of the Agreement evidencing the award. The Committee may, in its sole discretion and for any reason at any time, subject to the requirements of Section 162(m) of the Code and regulations thereunder in the case of an award intended to be qualified performance-based compensation, take action such that (i) any or all outstanding options and SARs shall become exercisable in part or in full, (ii) all or a portion of the Restriction Period applicable to any outstanding Restricted Stock or Restricted Stock Units shall lapse, (iii) all or a portion of the Performance Period applicable to any outstanding Performance Share Award or Performance Units shall lapse and (iv) the Performance Measures (if any) applicable to any outstanding award shall be deemed to be satisfied at the target or any other level not exceeding the maximum allowable under its terms. The Committee shall, subject to the terms of this Plan, interpret this Plan and the application thereof, establish rules and regulations it deems necessary or desirable for the administration of this Plan and may impose, incidental to the grant of an award, conditions with respect to the award, such as limiting competitive employment or other activities. All such interpretations, rules, regulations and conditions shall be conclusive and binding on all parties.

The Committee may delegate some or all of its power and authority hereunder to the Board or, subject to applicable law, to the Chief Executive Officer or other officer of the Company as the Committee deems appropriate; provided, however, that (i) the Committee may not delegate its power and authority to the Board or the Chief Executive Officer or other officer of the Company with regard to the grant of an award to any person who is a "covered employee" within the meaning of Section 162(m) of the Code or who, in the Committee's judgment, is likely to be a covered employee at the time during the period an award hereunder to such employee would be outstanding, (ii) the Committee may not delegate its power and authority to the Chief Executive Officer or other officer of the Company with regard to the selection for participation in this Plan of an officer or other person subject to Section 16 of the Exchange Act or whose title with the Company is "executive vice president" or higher, or decisions concerning the timing, pricing or amount of an award to such an officer or other person and (iii) the awards granted by the Chief Executive Officer pursuant to such delegation shall not exceed the limits set forth in Section 1.6(c) and 1.6(d).

No member of the Board or Committee, and neither the Chief Executive Officer nor any other officer to whom the Committee delegates any of its power and authority hereunder, shall be liable for any act, omission, interpretation, construction or determination made in connection with this Plan in good faith, and the members of the Board and the Committee and the Chief Executive Officer or other officer shall be entitled to indemnification and reimbursement by the Company in respect of any claim, loss, damage or expense (including attorneys' fees) arising therefrom to the full extent permitted by law (except as otherwise may be provided in the Company's Articles of Incorporation and/or By-laws) and under any directors' and officers' liability insurance that may be in effect from time to time.

A majority of the Committee shall constitute a quorum. The acts of the Committee shall be either (i) acts of a majority of the members of the Committee present at any meeting at which a quorum is present or (ii) acts approved in writing by all of the members of the Committee without a meeting.

**1.4** **Eligibility**. Participants in this Plan shall consist of such officers and other key management employees, and persons expected to become officers and other key management employees, of the Company and its Subsidiaries as the Committee in its sole discretion may select from time to time. The Committee's selection of a person to participate in this Plan at any time shall not require the Committee to select such person to participate in this Plan at any other time. For purposes of this Plan, references to employment by the Company shall also mean employment by a Subsidiary.

**1.5** **Shares Available**. Subject to adjustment as provided in Section 5.7, the aggregate number of shares of Common Stock available for awards granted under the Plan in the form of options, SARs, Stock Awards or Performance Units shall be the sum of (i) five million (5,000,000), plus (ii) the number of shares of Common Stock which as of the effective date of this Plan remain available for future awards pursuant to Section 1.5 of the Prior Plan, and reduced by the sum of the aggregate number of shares of Common Stock which become subject to outstanding options, outstanding Free-Standing SARs and outstanding Stock Awards granted under the Plan and shares of Common Stock delivered upon

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the settlement of Performance Units granted under the Plan. To the extent that shares of Common Stock subject to an outstanding option, SAR or stock award granted under the Plan or any predecessor plan are not issued or delivered by reason of the expiration, termination, cancellation or forfeiture of such award (excluding shares subject to an option cancelled upon settlement in shares of a related tandem SAR or shares subject to a tandem SAR cancelled upon exercise of a related option), then such shares of Common Stock shall again be available under this Plan. Shares of Common Stock to be delivered under this Plan shall be made available from authorized and unissued shares of Common Stock, or authorized and issued shares of Common Stock reacquired and held as treasury shares or otherwise or a combination thereof.

**1.6** **Award Limits**.

(a) Subject to adjustment as provided in Section 5.7, no individual may be granted awards under the Plan during any calendar year that, in the aggregate, may be settled by delivery of more than two million (2,000,000) shares of Common Stock. In addition, with respect to awards the value of which is based on the Fair Market Value of Common Stock and that may be settled in cash (in whole or in part), no individual may be paid during any calendar year cash amounts relating to such awards that exceed the greater of the Fair Market Value of the number of shares of Common Stock set forth in the preceding sentence either at the date of grant or at the date of settlement. This Section 1.6(a) sets forth two separate limitations, so that awards that may be settled solely by delivery of Common Stock will not operate to reduce the amount or value of cash-only awards, and vice versa; nevertheless, awards that may be settled in Common Stock or cash must not exceed either limitation.

(b) With respect to awards, the value of which is not based on the Fair Market Value of Common Stock, no individual may receive during any calendar year cash or shares of Common Stock with a Fair Market Value at the date of settlement that, in the aggregate, exceeds five million dollars ($5,000,000).

(c) Subject to adjustment as provided in Section 5.7, the number of shares of Common Stock subject to options and SARs granted in any single year by the Chief Executive Officer, pursuant to a delegation by the Committee in accordance with Section 1.3 of this Plan, shall not exceed 1,200,000 in the aggregate or 40,000 with respect to any individual employee.

(d) Subject to adjustment as provided in Section 5.7, the number of shares of Common Stock subject to Stock Awards and Performance Units granted in any single year by the Chief Executive Officer, pursuant to a delegation by the Committee in accordance with Section 1.3 of this Plan, shall not exceed 600,000 in the aggregate or 20,000 with respect to any individual employee.

## II. STOCK OPTIONS AND STOCK APPRECIATION RIGHTS

**2.1** **Stock Options**. The Committee may, in its discretion, grant options to purchase shares of Common Stock to such eligible persons as may be selected by the Committee. Each option, or portion thereof, that is not an Incentive Stock Option, shall be a Nonqualified Stock Option. Each option shall be granted within 10 years after the date on which this Plan is approved by the Board. To the extent that the aggregate Fair Market Value (determined as of the date of grant) of shares of Common Stock with respect to which options designated as Incentive Stock Options are exercisable for the first time by a participant during any calendar year (under this Plan or any other plan of the Company, or any parent or Subsidiary) exceeds the amount (currently $100,000) established by the Code, such options shall constitute Nonqualified Stock Options.

Options shall be subject to the following terms and conditions and shall contain such additional terms and conditions, not inconsistent with the terms of this Plan, as the Committee shall deem advisable:

(a) Number of Shares and Purchase Price. The number of shares of Common Stock subject to an option and the purchase price per share of Common Stock purchasable upon exercise of the option shall be determined by the Committee; provided, however, that the purchase price per share of Common Stock purchasable upon exercise of a Nonqualified Stock Option or an Incentive Stock Option shall not be less than 100% of the Fair Market Value of a share of Common Stock on the date of grant of such option; provided further, that if an Incentive Stock Option shall be granted to any person who, at the time such option is granted, owns capital stock possessing more than 10 percent of the total combined voting power of all classes of capital stock of the Company (or of any parent or Subsidiary) (a "Ten Percent Holder"), the purchase price per share of Common Stock shall not be less than the price (currently 110% of Fair Market Value) required by the Code in order to constitute an Incentive Stock Option.

(b) Option Period and Exercisability. The period during which an option may be exercised shall be determined by the Committee; provided, however, that no option shall be exercised later than 10 years after its date of grant; provided further, that if an Incentive Stock Option shall be granted to a Ten Percent Holder, such option shall not be exercised later than five years after its date of grant. The Committee may, in its discretion, determine that an option is to be granted as a Performance Option and may establish an applicable Performance Period and Performance Measures which shall be satisfied or met as a condition to the grant of such option or to the exercisability of all or a portion of such option. The Committee shall determine whether an option shall become exercisable in cumulative or non-cumulative installments and in part or in full at any time. An exercisable option, or portion thereof, may be exercised only with respect to whole shares of Common Stock.

(c) Method of Exercise. An option may be exercised (i) by giving written notice to the Company specifying the number of whole shares of Common Stock to be purchased and accompanying such notice with payment therefor in full, and without any extension of credit, either (A) in cash, (B) by delivery (either actual delivery or by attestation procedures established by the Company) to the Company of previously owned whole shares of Common Stock having a Fair Market Value, determined as of the date of exercise, equal to the aggregate purchase price payable by reason of such exercise, (C) authorizing the Company to withhold whole shares of Common Stock which would otherwise be delivered having an aggregate Fair Market Value, determined as of the date of exercise, equal to the amount necessary to satisfy such obligation, provided that the Committee determines that such withholding of shares does not cause the Company to recognize an increased compensation expense under applicable accounting principles, (D) except as may be prohibited by applicable law, in cash by a broker-dealer acceptable to the Company to whom the optionee has submitted an irrevocable notice of exercise or (E) a combination of (A), (B) and (C), in each case to the extent set forth in the Agreement relating to the option, (ii) if applicable, by surrendering to the Company any Tandem SARs which are cancelled by reason of the exercise of the option and (iii) by executing such documents as the Company may reasonably request. Any fraction of a share of Common Stock which would be required to pay such purchase price shall be disregarded and the remaining amount due shall be paid in cash by the optionee. No shares of Common Stock shall be issued and no certificate representing Common Stock shall be delivered until the full purchase price therefor and any withholding taxes thereon, as described in Section 5.5, have been paid.

**2.2 Stock Appreciation Rights.** The Committee may, in its discretion, grant SARs to such eligible persons as may be selected by the Committee. The Agreement relating to an SAR shall specify whether the SAR is a Tandem SAR or a Free-Standing SAR.

SARs shall be subject to the following terms and conditions and shall contain such additional terms and conditions, not inconsistent with the terms of this Plan, as the Committee shall deem advisable:

(a) Number of SARs and Base Price. The number of SARs subject to an award shall be determined by the Committee. Any Tandem SAR related to an Incentive Stock Option shall be granted at the same time that such Incentive Stock Option is granted. The base price of a Tandem SAR shall be the purchase price per share of Common Stock of the related option. The base price of a Free-Standing SAR shall be determined by the Committee; provided, however, that such base price shall not be less than 100% of the Fair Market Value of a share of Common Stock on the date of grant of such SAR.

(b) Exercise Period and Exercisability. The Agreement relating to an award of SARs shall specify whether such award may be settled in shares of Common Stock (including shares of Restricted Stock) or cash or a combination thereof. The period for the exercise of an SAR shall be determined by the Committee; provided, however, that no SAR shall be exercised later than 10 years after its date of grant; and provided, further, that no Tandem SAR shall be exercised later than the expiration, cancellation, forfeiture or other termination of the related option. The Committee may, in its discretion, establish Performance Measures which shall be satisfied or met as a condition to the grant of an SAR or to the exercisability of all or a portion of an SAR. The Committee shall determine whether an SAR may be exercised in cumulative or non-cumulative installments and in part or in full at any time. An exercisable SAR, or portion thereof, may be exercised, in the case of a Tandem SAR, only with respect to whole shares of Common Stock and, in the case of a Free-Standing SAR, only with respect to a whole number of SARs. If an SAR is exercised for shares of Restricted Stock, a certificate or certificates representing such Restricted Stock shall be issued in accordance with Section 3.2(c), or such shares shall be transferred to the holder in book entry form with restrictions on the Shares duly noted, and the holder of such Restricted Stock shall have such rights of a stockholder of the Company as determined pursuant to Section 3.2(d). Prior to the exercise of an SAR for shares of Common Stock, including Restricted Stock, the holder of such SAR shall have no rights as a stockholder of the Company with respect to the shares of Common Stock subject to such SAR.

(c) Method of Exercise. A Tandem SAR may be exercised (i) by giving written notice to the Company specifying the number of whole SARs which are being exercised, (ii) by surrendering to the Company any options which are cancelled by reason of the exercise of the Tandem SAR and (iii) by executing such documents as the Company may reasonably request. A Free-Standing SAR may be exercised (A) by giving written notice to the Company specifying the whole number of SARs which are being exercised and (B) by executing such documents as the Company may reasonably request.

**2.3 Termination of Employment.**

(a) Retirement or Disability. Subject to Sections 2.3(e) and 2.3(g) below, and unless otherwise specified in the Agreement relating to an option or SAR, as the case may be, if the Company ceases to employ the holder of an option or SAR by reason of such holder's Retirement or Disability, each option and SAR held by such holder shall be fully exercisable, and may thereafter be exercised by such holder (or such holder's legal representative or similar person) until and including the earlier to occur of (i) the date which is five years after the effective date of such holder's termination of employment and (ii) the expiration date of the term of such option or SAR.

(b) Death. Unless otherwise specified in the Agreement relating to an option or SAR, as the case may be, if the Company ceases to employ the holder of an option or SAR by reason of such holder's death, each option and SAR held by such holder shall be fully exercisable, and may thereafter be exercised by such holder's executor, administrator, legal representative, beneficiary or similar person until and including the earlier to occur of (i) the date which is three years after the date of death and (ii) the expiration date of the term of such option or SAR.

(c) Cause. If the Company ceases to employ the holder of an option or SAR due to a termination of employment by the Company for Cause, each option and SAR held by such holder shall be cancelled and cease to be exercisable as of the earlier to occur of (i) the effective date of such termination of employment and (ii) the date on which the holder first engaged in conduct giving rise to a termination for Cause, and the Company thereafter may require the repayment of any amounts received by such holder in connection with an exercise of such option or SAR following such cancellation date.

(d) Other Termination. Subject to Sections 2.3(e), 2.3(f) and 2.3(g) below and unless otherwise specified in the Agreement relating to an option or SAR, as the case may be, if the Company ceases to employ the holder of an option or SAR for any reason other than as described in Section 2.3(a) through Section 2.3(c), then each option and SAR held by such holder shall be exercisable only to the extent that such option or SAR is exercisable on the effective date of such holder's termination of employment, and may thereafter be exercised by such holder (or such holder's legal representative or similar person) until and including the earlier to occur of (i) the date which is 90 days after the effective date of such holder's termination of employment and (ii) the expiration date of the term of such option or SAR.

(e) Death Following Termination of Employment. Unless otherwise specified in the Agreement relating to an option or SAR, as the case may be, if the holder of an option or SAR dies during the applicable post-termination exercise period described in Section 2.3(d), each option and SAR held by such holder shall be exercisable only to the extent that such option or SAR, as the case may be, is exercisable on the date of such holder's death and may thereafter be exercised by the holder's executor, administrator, legal representative, beneficiary or similar person until and including the earlier to occur of (i) the date which is one year after the date of death and (ii) the expiration date of the term of such option or SAR.

(f) Breach of Restrictive Covenant. Notwithstanding Sections 2.3(a) through (e), if the holder of an option or SAR breaches his or her obligations to the Company or any of its affiliates under a noncompetition, nonsolicitation, confidentiality, intellectual property or other restrictive covenant (a "Restrictive Covenant"), each option and SAR held by such holder shall be cancelled and cease to be exercisable as of the date on which the holder first breached such Restrictive Covenant, and the Company thereafter may require the repayment of any amounts received by such holder in connection with an exercise of such option or SAR following such cancellation date.

(g) Certain Terminations After Change in Control. Unless otherwise specified in, and subject to all conditions set forth in, the Agreement relating to an option or SAR, as the case may be, or any individual change in control agreement or severance plan, and notwithstanding any other provision of this Section 2.3, if within 24 months following a Change in Control, the Company ceases to employ the holder of an option or SAR due to a termination of employment (i) by the Company other than for Cause, or (ii) with respect to a holder whose position is at least salary band E09 (or its equivalent), by the holder for Good Reason, such holder's outstanding options shall immediately become fully exercisable and may thereafter be exercised by such holder (or such holder's legal representative or similar person) until and including the earlier to occur of (A) the date which is five years after the effective date of such holder's termination of employment and (B) the expiration date of the term of such option or SAR.

**2.4** **No Repricing.** The Committee shall not without the approval of the stockholders of the Company, (i) reduce the purchase price or base price of any previously granted option or SAR, (ii) cancel any previously granted option or SAR in exchange for another option or SAR with a lower purchase price or base price or (iii) cancel any previously granted option or SAR in exchange for cash or another award if the purchase price of such option or the base price of such SAR exceeds the Fair Market Value of a share of Common Stock on the date of such cancellation, in each case, other than in connection with a Change in Control or the adjustment provisions set forth in Section 5.7.

## III. STOCK AWARDS

**3.1** **Stock Awards.** The Committee may, in its discretion, grant Stock Awards to such eligible persons as may be selected by the Committee. The Agreement relating to a Stock Award shall specify whether the Stock Award is a Restricted Stock Award or a Restricted Stock Unit Award. The Committee may, in its discretion, determine that a Restricted Stock Award or Restricted Stock Unit Award is to be granted as a Performance Share Award and may establish an applicable Performance Period and Performance Measures which shall be satisfied or met as a condition to the grant or vesting of all or a portion of such award.

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**3.2 Terms of Restricted Stock Awards**. Restricted Stock Awards shall be subject to the following terms and conditions and shall be subject to such additional terms and conditions, not inconsistent with the terms of this Plan, as the Committee shall deem advisable.

(a) Number of Shares and Other Terms. The number of shares of Common Stock subject to a Restricted Stock Award and the Restriction Period and Performance Measures (if any) applicable to a Restricted Stock Award shall be determined by the Committee.

(b) Vesting and Forfeiture. The Agreement relating to a Restricted Stock Award shall provide, in the manner determined by the Committee, in its discretion, and subject to the provisions of this Plan, for the vesting of the shares of Common Stock subject to such award (i) if the holder of such award remains continuously in the employment of the Company during the specified Restriction Period and (ii) in the case of a Performance Share Award, if specified Performance Measures are satisfied or met during a specified Performance Period, and for the forfeiture of the shares of Common Stock subject to such award (x) if the holder of such award does not remain continuously in the employment of the Company during the specified Restriction Period or (y) in the case of a Performance Share Award, if specified Performance Measures are not satisfied or met during a specified Performance Period. The restrictions applicable to each Performance Share Award shall lapse no earlier than one year after the applicable grant date, except to the extent an award Agreement provides otherwise in the case of a Change in Control or a participant's death, Disability or termination of employment.

(c) Stock Issuance. During the Restriction Period, the shares of Restricted Stock shall be held by a custodian in book entry form with restrictions on such shares duly noted or, alternatively, a certificate or certificates representing a Restricted Stock Award shall be registered in the holder's name and may bear a legend, in addition to any legend which may be required pursuant to Section 5.6, indicating that the ownership of the shares of Common Stock represented by such certificate is subject to the restrictions, terms and conditions of this Plan and the Agreement relating to the Restricted Stock Award. All such certificates shall be deposited with the Company, together with stock powers or other instruments of assignment (including a power of attorney), each endorsed in blank with a guarantee of signature if deemed necessary or appropriate, which would permit transfer to the Company of all or a portion of the shares of Common Stock subject to the Restricted Stock Award in the event such award is forfeited in whole or in part. Upon termination of any applicable Restriction Period (and the satisfaction or attainment of applicable Performance Measures), subject to the Company's right to require payment of any taxes in accordance with Section 5.5, the restrictions shall be removed from the requisite number of any shares of Common Stock that are held in book entry form, and all certificates evidencing ownership of the requisite number of shares of Common Stock shall be delivered to the holder of such award.

(d) Rights with Respect to Restricted Stock Awards. Unless otherwise set forth in the Agreement relating to a Restricted Stock Award, and subject to the terms and conditions of a Restricted Stock Award, the holder of such award shall have all rights as a stockholder of the Company, including, but not limited to, voting rights, the right to receive dividends and the right to participate in any capital adjustment applicable to all holders of Common Stock; provided, however, that (i) a distribution with respect to shares of Common Stock, other than a regular cash dividend, and (ii) a regular cash dividend with respect to shares of Common Stock that are subject to performance-based vesting conditions, in each case shall be deposited with the Company and shall be subject to the same restrictions as the shares of Common Stock with respect to which such distribution was made.

**3.3 Terms of Restricted Stock Unit Awards**. Restricted Stock Unit Awards shall be subject to the following terms and conditions and shall contain such additional terms and conditions, not inconsistent with the terms of this Plan, as the Committee shall deem advisable.

(a) Number of Shares and Other Terms. The number of shares of Common Stock subject to a Restricted Stock Unit Award and the Restriction Period and Performance Measures (if any) applicable to a Restricted Stock Unit Award shall be determined by the Committee.

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(b) Vesting and Forfeiture. The Agreement relating to a Restricted Stock Unit Award shall provide, in the manner determined by the Committee, in its discretion, and subject to the provisions of this Plan, for the vesting of such Restricted Stock Unit Award (i) if the holder of such award remains continuously in the employment of the Company during the specified Restriction Period and (ii) in the case of a Performance Share Award, if specified Performance Measures are satisfied or met during a specified Performance Period, and for the forfeiture of the shares of Common Stock subject to such award (x) if the holder of such award does not remain continuously in the employment of the Company during the specified Restriction Period or (y) in the case of a Performance Share Award, if specified Performance Measures are not satisfied or met during a specified Performance Period. Each Performance Share Award shall become vested no earlier than one year after the applicable grant date, except to the extent an award Agreement provides otherwise in the case of a Change in Control or a participant's death, Disability or termination of employment.

(c) Settlement of Vested Restricted Stock Unit Awards. The Agreement relating to a Restricted Stock Unit Award shall specify (i) whether such award may be settled in shares of Common Stock, including Restricted Stock, or cash or a combination thereof and (ii) whether the holder thereof shall be entitled to receive, on a current or deferred basis, dividend equivalents and, if determined by the Committee, interest on, or the deemed reinvestment of, any deferred dividend equivalents, with respect to the number of shares of Common Stock subject to such award. Prior to the settlement of a Restricted Stock Unit Award, the holder of such award shall have no rights as a stockholder of the Company with respect to the shares of Common Stock subject to such award.

3.4 **Termination of Employment**. All of the terms relating to the satisfaction of Performance Measures and the termination of the Restriction Period or Performance Period relating to a Stock Award, or any forfeiture and cancellation of such award upon a termination of employment with the Company of the holder of such award, whether by reason of Disability, Retirement, death or any other reason, shall be determined by the Committee and set forth in the applicable award Agreement.

**IV. PERFORMANCE UNIT AWARDS**

4.1 **Performance Unit Awards**. The Committee may, in its discretion, grant Performance Unit Awards to such eligible persons as may be selected by the Committee.

4.2 **Terms of Performance Unit Awards.** Performance Unit Awards shall be subject to the following terms and conditions and shall be subject to such additional terms and conditions, not inconsistent with the terms of this Plan, as the Committee shall deem advisable.

(a) Number of Performance Units and Performance Measures. The number of Performance Units subject to a Performance Unit Award and the Performance Measures and Performance Period applicable to a Performance Unit Award shall be determined by the Committee.

(b) Vesting and Forfeiture. The Agreement relating to a Performance Unit Award shall provide, in the manner determined by the Committee, in its discretion, and subject to the provisions of this Plan, for the vesting of such Performance Unit Award if the specified Performance Measures are satisfied or met during the specified Performance Period and for the forfeiture of such award if the specified Performance Measures are not satisfied or met during the specified Performance Period.

(c) Settlement of Vested Performance Unit Awards. The Agreement relating to a Performance Unit Award shall specify whether such award may be settled in shares of Common Stock (including shares of Restricted Stock) or cash or a combination thereof. If a Performance Unit Award is settled in shares of Restricted Stock, such shares of Restricted Stock shall be issued to the holder in book entry form or a certificate or certificates representing such Restricted Stock shall be issued in accordance with Section 3.2(c) and the holder of such Restricted Stock

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# Appendix A

shall have such rights as a stockholder of the Company as determined pursuant to Section 3.2(d). Prior to the settlement of a Performance Unit Award in shares of Common Stock, including Restricted Stock, the holder of such award shall have no rights as a stockholder of the Company.

**4.3** **Termination of Employment**. All of the terms relating to the satisfaction of Performance Measures and the termination of the Performance Period relating to a Performance Unit Award, or any forfeiture and cancellation of such award upon a termination of employment with the Company of the holder of such award, whether by reason of Disability, Retirement, death or any other reason, shall be determined by the Committee and set forth in the applicable award Agreement.

**V. GENERAL**

**5.1** **Effective Date and Term of Plan**. This Plan shall be submitted to the stockholders of the Company for approval at the Company's 2010 annual meeting of stockholders and, if approved by the affirmative vote of a majority of the shares of Common Stock present in person or represented by proxy at such annual meeting of stockholders, shall become effective as of January 1, 2011. This Plan shall terminate ten (10) years after its effective date, unless terminated earlier by the Committee. Termination of this Plan shall not affect the terms or conditions of any award granted prior to termination.

Awards hereunder may be made at any time prior to the termination of this Plan, provided that, subject to Section 2.1, no award may be made later than ten (10) years after the effective date of this Plan. In the event that this Plan is not approved by the stockholders of the Company, this Plan and any awards hereunder shall be void and of no force or effect.

**5.2** **Amendments**. The Committee may amend this Plan as it shall deem advisable, subject to any requirement of stockholder approval required by applicable law, rule or regulation, including Section 162(m) of the Code and any rule of the New York Stock Exchange, or, if the Common Stock is not listed on the New York Stock Exchange, any rule of the principal national stock exchange on which the Common Stock is then traded; provided, however, that no amendment may impair the rights of a holder of an outstanding award without the consent of such holder.

**5.3** **Agreement**. Each award under this Plan shall be evidenced by an Agreement setting forth the terms and conditions applicable to such award. No award shall be valid until an Agreement is executed by the Company and the recipient of such award and, upon execution by each party and delivery of the Agreement to the Company within the time period specified by the Company, such award shall be effective as of the effective date set forth in the Agreement.

**5.4** **Non-Transferability.** No award shall be transferable other than by will, the laws of descent and distribution or pursuant to beneficiary designation procedures approved by the Company or, to the extent expressly permitted in the Agreement relating to such award, to the holder's family members, a trust or entity established by the holder for estate planning purposes or a charitable organization designated by the holder. Except to the extent permitted by the foregoing sentence or the Agreement relating to an award, each award may be exercised or settled during the holder's lifetime only by the holder or the holder's legal representative or similar person. Except as permitted by the second preceding sentence, no award may be sold, transferred, assigned, pledged, hypothecated, encumbered or otherwise disposed of (whether by operation of law or otherwise) or be subject to execution, attachment or similar process. Upon any attempt to so sell, transfer, assign, pledge, hypothecate, encumber or otherwise dispose of any award, such award and all rights thereunder shall immediately become null and void.

**5.5** **Tax Withholding**. The Company shall have the right to require, prior to the issuance or delivery of any shares of Common Stock or the payment of any cash pursuant to an award made hereunder, or upon the vesting of any award that is considered deferred compensation, payment by the holder of such award of any federal, state, local or other taxes which may be required to be withheld or paid in connection with such award. An Agreement may provide that (i) the Company shall withhold whole shares of Common Stock which would otherwise be delivered to a holder, having

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an aggregate Fair Market Value determined as of the date the obligation to withhold or pay taxes arises in connection with an award (the "Tax Date"), or withhold an amount of cash which would otherwise be payable to a holder, in the amount necessary to satisfy any such obligation or (ii) the holder may satisfy any such obligation by any of the following means: (A) a cash payment to the Company, (B) authorizing the Company to withhold whole shares of Common Stock which would otherwise be delivered having an aggregate Fair Market Value, determined as of the Tax Date, or withhold an amount of cash which would otherwise be payable to a holder, equal to the amount necessary to satisfy any such obligation, (C) in the case of the exercise of an option and except as may be prohibited by applicable law, a cash payment by a broker-dealer acceptable to the Company to whom the optionee has submitted an irrevocable notice of exercise or (D) any combination of (A) and (B), in each case to the extent set forth in the Agreement relating to the award. Shares of Common Stock to be delivered or withheld may not have an aggregate Fair Market Value in excess of the amount determined by applying the minimum statutory withholding rate. Any fraction of a share of Common Stock which would be required to satisfy such an obligation shall be disregarded and the remaining amount due shall be paid in cash by the holder.

**5.6** **Restrictions on Shares**. Each award made hereunder shall be subject to the requirement that if at any time the Company determines that the listing, registration or qualification of the shares of Common Stock subject to such award upon any securities exchange or under any law, or the consent or approval of any governmental body, or the taking of any other action is necessary or desirable as a condition of, or in connection with, the delivery of shares thereunder, such shares shall not be delivered unless such listing, registration, qualification, consent, approval or other action shall have been effected or obtained, free of any conditions not acceptable to the Company. The Company may require that certificates evidencing shares of Common Stock delivered pursuant to any award made hereunder bear a legend indicating that the sale, transfer or other disposition thereof by the holder is prohibited except in compliance with the Securities Act of 1933, as amended, and the rules and regulations thereunder.

**5.7** **Adjustment**. In the event any stock split, stock dividend, recapitalization, reorganization, merger, consolidation, combination, exchange of shares, liquidation, spin-off or other similar change in capitalization or event, or any distribution to holders of Common Stock (other than a regular cash dividend) occurs on or after the date this Plan is approved by the stockholders of the Company, the number and class of securities available for all awards under this Plan, the maximum number of securities with respect to which awards may be granted during any year to any one person, the maximum number of shares subject to awards granted during any year by the Chief Executive Officer, the number and class of securities subject to each outstanding option and the purchase price per security, and the terms of each outstanding SAR, Restricted Stock Award, Restricted Stock Unit Award, Performance Share Award and Performance Unit Award, including the number and class of securities subject thereto, shall be appropriately adjusted by the Committee, such adjustments to be made in the case of outstanding options and SARs without an increase in the aggregate purchase price or base price. The decision of the Committee regarding any such adjustment shall be final, binding and conclusive. If any such adjustment would result in a fractional security being (a) available under this Plan, such fractional security shall be disregarded, or (b) subject to an award under this Plan, the Company shall pay the holder of such award, in connection with the first vesting, exercise or settlement of such award, in whole or in part, occurring after such adjustment, an amount in cash determined by multiplying (i) the fraction of such security (rounded to the nearest hundredth) by (ii) the excess, if any, of (A) the Fair Market Value on the vesting, exercise or settlement date over (B) the exercise or base price, if any, of such award.

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**5.8 Corporate Transactions; Change in Control.**

(a) If the Company shall be a party to a reorganization, merger, or consolidation or sale or other disposition of more than 50% of the operating assets of the Company (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) (a "Corporate Transaction"), the Board (as constituted prior to any Change in Control resulting from such Corporate Transaction) may, in its discretion:

(i) require that (A) some or all outstanding options and SARs shall immediately become exercisable in full or in part, (B) the Restriction Period applicable to some or all outstanding Restricted Stock Awards and Restricted Stock Unit Awards shall lapse in full or in part, (C) the Performance Period applicable to some or all outstanding Performance Share Awards and Performance Unit Awards shall lapse in full or in part, and (D) the Performance Measures applicable to some or all outstanding awards shall be deemed to be satisfied at the target or any other level not exceeding the maximum levels allowable under their respective terms;

(ii) require that shares of capital stock of the corporation resulting from such Corporate Transaction, or a parent corporation thereof, be substituted for some or all of the shares of Common Stock subject to an outstanding award, with an appropriate and equitable adjustment to such award as determined by the Board in accordance with Section 5.7; and/or

(iii) require outstanding awards, in whole or in part, to be surrendered to the Company by the holder, and to be immediately cancelled by the Company, and to provide for the holder to receive (A) a cash payment in an amount equal to (1) in the case of an option or an SAR, the number of shares of Common Stock then subject to the portion of such option or SAR surrendered, to the extent such option or SAR is then exercisable or becomes exercisable pursuant to clause (i), multiplied by the excess, if any, of the Fair Market Value of a share of Common Stock as of the date of the Corporate Transaction, over the purchase price or base price per share of Common Stock subject to such option or SAR, (2) in the case of a Stock Award, the number of shares of Common Stock then subject to the portion of such award surrendered, to the extent the Restriction Period and Performance Period, if any, on such Stock Award have lapsed or will lapse pursuant to clause (i) and to the extent that the Performance Measures, if any, have been satisfied or are deemed satisfied pursuant to clause (i), multiplied by the Fair Market Value of a share of Common Stock as of the date of the Corporate Transaction, and (3) in the case of a Performance Unit Award, the value of the Performance Units then subject to the portion of such award surrendered, to the extent the Performance Period applicable so such award has lapsed or will lapse pursuant to clause (i) and to the extent the Performance Measures applicable to such award have been satisfied or are deemed satisfied pursuant to clause (i); (B) shares of capital stock of the corporation resulting from such Corporate Transaction, or a parent corporation thereof, having a fair market value not less than the amount determined under clause (A) above; or (C) a combination of the payment of cash pursuant to clause (A) above and the issuance of shares pursuant to clause (B) above.

(b) For purposes of Sections 2.3(f) and 5.8(a), "Change in Control" shall mean, except as otherwise provided below, the first to occur of any of the following events:

(i) any SEC Person becomes the Beneficial Owner of 20% or more of the then outstanding common stock of the Company or of Voting Securities representing 20% or more of the combined voting power of all the then outstanding Voting Securities of the Company (such an SEC Person, a "20% Owner"); provided, however, that for purposes of this subsection (i), the following acquisitions shall not constitute a Change in Control: (1) any acquisition directly from the Company (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 the Company), (2) any acquisition by the Company, (3) any acquisition by an

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employee benefit plan (or related trust) sponsored or maintained by the Company or any corporation controlled by the Company (a "Company Plan"), or (4) any acquisition by any corporation pursuant to a transaction which complies with paragraphs (A), (B) and (C) of subsection (iii) of this definition; provided further, that for purposes of clause (2), if any 20% Owner of the Company other than the Company or any Company Plan becomes a 20% Owner by reason of an acquisition by the Company, and such 20% Owner of the Company shall, after such acquisition by the Company, become the Beneficial Owner of any additional outstanding common shares of the Company or any additional outstanding Voting Securities of the Company (other than pursuant to any dividend reinvestment plan or arrangement maintained by the Company) and such beneficial ownership is publicly announced, such additional beneficial ownership shall constitute a Change in Control; or

(ii) Individuals who, as of the effective 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 the Company'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

(iii) Consummation of a Corporate Transaction by the Company; excluding, however, a Corporate Transaction pursuant to which:

(A) all or substantially all of the individuals and entities who are the Beneficial Owners, respectively, of the outstanding common stock of Company and outstanding Voting Securities of the Company 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 the Company or all or substantially all of the assets of the Company 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 the Company, as the case may be;

(B) 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 the Company or the outstanding Voting Securities of the Company, 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

(C) 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

(iv) Approval by the Company's shareholders of a plan of complete liquidation or dissolution of the Company, other than a plan of liquidation or dissolution which results in the acquisition of all or substantially all of the assets of the Company by an affiliated company.

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Notwithstanding the occurrence of any of the foregoing events, a Change in Control shall not occur with respect to an award if, in advance of such event, the holder of such award agrees in writing that such event shall not constitute a Change in Control.

**5.9** **Deferrals**. The Committee may determine that the delivery of shares of Common Stock or the payment of cash, or a combination thereof, upon the exercise or settlement of all or a portion of any award made hereunder shall be deferred, or the Committee may, in its sole discretion, approve deferral elections made by holders of awards. Deferrals shall be for such periods and upon such terms as shall be set forth in a deferral plan or program established by the Committee in its sole discretion in accordance with Section 409A of the Code.

**5.10** **No Right of Participation or Employment**. Unless otherwise set forth in an employment agreement, no person shall have any right to participate in this Plan. Neither this Plan nor any award made hereunder shall confer upon any person any right to continued employment with the Company, any Subsidiary or any affiliate of the Company or affect in any manner the right of the Company, any Subsidiary or any affiliate of the Company to terminate the employment of any person at any time without liability hereunder.

**5.11** **Rights as Stockholder**. No person shall have any right as a stockholder of the Company with respect to any shares of Common Stock or other equity security of the Company which is subject to an award hereunder unless and until such person becomes a stockholder of record with respect to such shares of Common Stock or equity security.

**5.12** **Designation of Beneficiary**. A holder of an award may file with the Committee a written designation of one or more persons as such holder's beneficiary or beneficiaries (both primary and contingent) in the event of the holder's death or incapacity. To the extent an outstanding option or SAR granted hereunder is exercisable, such beneficiary or beneficiaries shall be entitled to exercise such option or SAR pursuant to procedures prescribed by the Committee.

Each beneficiary designation shall become effective only when filed in writing with the Committee during the holder's lifetime on a form prescribed by the Committee. The spouse of a married holder domiciled in a community property jurisdiction shall join in any designation of a beneficiary other than such spouse. The filing with the Committee of a new beneficiary designation shall cancel all previously filed beneficiary designations.

If a holder fails to designate a beneficiary, or if all designated beneficiaries of a holder predecease the holder, then each outstanding option and SAR hereunder held by such holder, to the extent exercisable, may be exercised by such holder's executor, administrator, legal representative or similar person.

**5.13** **Governing Law**. This Plan, each award hereunder and the related Agreement, and all determinations made and actions taken pursuant thereto, to the extent not otherwise governed by the Code or the laws of the United States, shall be governed by the laws of the Commonwealth of Pennsylvania and construed in accordance therewith without giving effect to principles of conflicts of laws.

**5.14** **Foreign Employees**. Without amending this Plan, the Committee may grant awards to eligible persons who are foreign nationals on such terms and conditions different from those specified in this Plan as may in the judgment of the Committee be necessary or desirable to foster and promote achievement of the purposes of this Plan and, in furtherance of such purposes the Committee may make such modifications, amendments, procedures, subplans and the like as may be necessary or advisable to comply with provisions of laws in other countries or jurisdictions in which the Company or its Subsidiaries operates or has employees.

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Chicago, IL 60680-5398

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Exelon

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**VOTE BY INTERNET - www.proxyvote.com**
Use the Internet to transmit your voting instructions and for electronic delivery of information up until 11:59 P.M. Eastern Time on April 27, 2015. Have your proxy card in hand when you access the web site and follow the instructions to obtain your records and to create an electronic voting instruction form.

**ELECTRONIC DELIVERY OF FUTURE PROXY MATERIALS**
If you would like to reduce the costs incurred by our company in mailing proxy materials, you can consent to receiving all future proxy statements, proxy cards and annual reports electronically via e-mail or the Internet. To sign up for electronic delivery, please follow the instructions above to vote using the Internet and, when prompted, indicate that you agree to receive or access proxy materials electronically in future years.

**VOTE BY PHONE - 1-800-690-6903**
Use any touch-tone telephone to transmit your voting instructions up until 11:59 P.M. Eastern Time on April 27, 2015. Have your proxy card in hand when you call and then follow the instructions.

**VOTE BY MAIL**
Mark, sign and date your proxy card and return it in the postage-paid envelope we have provided or return it to Vote Processing, c/o Broadridge, 51 Mercedes Way, Edgewood, NY 11717.

TO VOTE, MARK BLOCKS BELOW IN BLUE OR BLACK INK AS FOLLOWS:

M85192-P62030-265036 KEEP THIS PORTION FOR YOUR RECORDS

**THIS PROXY CARD IS VALID ONLY WHEN SIGNED AND DATED.** DETACH AND RETURN THIS PORTION ONLY

**EXELON CORPORATION**

**The board of directors recommends voting FOR Proposals 1 through 5 and AGAINST Proposal 6:**

1. Election of Directors

**Nominees:**

| | For | Against | Abstain |
|---|---|---|---|
| 1a. Anthony K. Anderson | ☐ | ☐ | ☐ |
| 1b. Ann C. Berzin | ☐ | ☐ | ☐ |
| 1c. John A. Canning, Jr. | ☐ | ☐ | ☐ |
| 1d. Christopher M. Crane | ☐ | ☐ | ☐ |
| 1e. Yves C. de Balmann | ☐ | ☐ | ☐ |
| 1f. Nicholas DeBenedictis | ☐ | ☐ | ☐ |
| 1g. Paul L. Joskow | ☐ | ☐ | ☐ |
| 1h. Robert J. Lawless | ☐ | ☐ | ☐ |
| 1i. Richard W. Mies | ☐ | ☐ | ☐ |
| 1j. William C. Richardson | ☐ | ☐ | ☐ |
| 1k. John W. Rogers, Jr. | ☐ | ☐ | ☐ |
| 1l. Mayo A. Shattuck III | ☐ | ☐ | ☐ |
| 1m. Stephen D. Steinour | ☐ | ☐ | ☐ |
| 2. The Ratification of PricewaterhouseCoopers LLP as Exelon's independent Auditor for 2015. | ☐ | ☐ | ☐ |
| 3. Advisory vote to approve executive compensation. | ☐ | ☐ | ☐ |
| 4. Approve performance measures in the 2011 Long-Term Incentive Plan. | ☐ | ☐ | ☐ |
| 5. Management proposal regarding proxy access. | ☐ | ☐ | ☐ |
| 6. Shareholder proposal regarding proxy access. | ☐ | ☐ | ☐ |

**NOTE:** Authority is also given to vote on all other matters that may properly come before the meeting or any adjournment thereof.

Please sign exactly as your name(s) appear(s) hereon. When signing as attorney, executor, administrator, or other fiduciary, please give full title as such. Joint owners should each sign personally. All holders must sign. If a corporation or partnership, please sign in full corporate or partnership name by authorized officer.

Signature [PLEASE SIGN WITHIN BOX] Date

Signature (Joint Owners) Date

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## ADMISSION TICKET

To attend the annual meeting please detach and bring this ticket along with a valid photo ID and present them at the Shareholder Registration Table upon arrival. This ticket is not transferable.

No cameras, audio or video recording equipment, similar electronic devices, large bags, backpacks, briefcases or packages will be permitted in the meeting room or adjacent areas. Cell phones and similar wireless communication devices will be permitted in the meeting only if turned off. All items brought into the meeting will be subject to search.

**NOTICE REGARDING INTERNET AVAILABILITY OF PROXY MATERIALS FOR THE ANNUAL MEETING**

Exelon's Notice and Proxy Statement and Annual Report are available online at www.proxyvote.com. The electronic documents have been prepared to offer easy viewing and are completely searchable. The website will allow you to view the materials as you vote the shares. We believe that you will find this method of viewing Exelon's information and voting the shares more convenient.

**We encourage you to vote the shares at www.proxyvote.com and then register for the electronic delivery of Exelon's proxy materials for 2016 and beyond.**

IF YOU WISH TO ATTEND THE ANNUAL MEETING, DETACH AND BRING THIS ADMISSION TICKET ALONG WITH A PHOTO ID

M85193-P62030-Z65036

## EXELON CORPORATION

## 2015 COMMON STOCK PROXY

**This proxy is solicited on behalf of the Board of Directors for the Annual Meeting of Shareholders to be held on Tuesday, April 28, 2015 at 9:00 A.M. Central Time at Exelon Corporation Headquarters 10 S. Dearborn Street Chicago, Illinois**

DARRYL M. BRADFORD and BRUCE G. WILSON, or either of them with power of substitution, are hereby appointed to vote as specified all shares of common stock which the shareholder(s) named on the proxy card is/are entitled to vote at the annual meeting described above or at any adjournment thereof, and in their sole discretion to vote upon all other matters that may be properly brought before the annual meeting. If the proxy card is signed and dated, but no votes are indicated, it will be voted as recommended by the Board of Directors.

The Northern Trust Company as trustee for the Exelon Employee Savings Plan, the Employee Savings Plan for Constellation Energy Nuclear Energy Group, LLC and the Represented Employee Savings Plan for Nine Mile Point, for which Hewitt Associates LLC is the plan record keeper, is hereby authorized to execute a proxy with the identical instructions for any shares of common stock held in this plan for the benefit of any shareholder(s) named on this card. For all shares for which no valid instruction is timely received, the trustee of the respective plan is instructed to vote the shares in the same proportion as the shares that were affirmatively voted by shareholders participating in the respective plan.

**Continued and to be signed on reverse side**

Q. III-F-2

Supply projected capital requirements and sources of the filing utility, its parent and system – consolidated – for the test year and each of 3 comparable future years.

A. III-F-2

Refer to Attachment III-F-2(a) for the Company's projected Capital requirements and sources in 2015 and 2016. Information for years 2017 through 2019 **IS CONFIDENTIAL AND SUBMITTED ONLY IN THE CONFIDENTIAL NON-PUBLIC VERSION FILED WITH THE COMMISSION.** Forward looking data for Parent and System consolidated is not applicable.

Note: The Company's projected capital requirements for 2015 through 2016 include projected capital requirements for Smart Meter project of $17M and $12M respectively. The capital requirements for 2017 and beyond for the Smart Meter project **IS CONFIDENTIAL AND SUBMITTED ONLY IN THE CONFIDENTIAL NON-PUBLIC VERSION FILED WITH THE COMMISSION.**

**PECO Distribution**
**REQUIREMENTS AND SOURCES OF FUNDS**
**(Millions of Dollars)**

**CASH FLOW DETAIL**

| | | Year 2015 | Year 2016 |
|---|---|---|---|
| | **CAPITAL REQUIREMENTS** | | |
| 1 | Capital Expenditures | $ 356 | $ 332 |
| 2 | **Cash used in Investing** | **$ 356** | **$ 332** |
| | **SOURCES** | | |
| | **OPERATING ACTIVITIES** | | |
| 3 | Net Income | $ 180 | $ 166 |
| 4 | Depreciation & Amortization | 181 | 188 |
| 5 | Change in Deferred Taxes | 7 | 10 |
| 6 | Change in Working Capital | (92) | 1 |
| 7 | **TOTAL INTERNAL** | **$ 276** | **$ 365** |
| | **FINANCING ACTIVITIES** | | |
| 8 | Change in Total Long-Term Debt | $ 235 | $ 34 |
| 9 | Change in Total Notes Payable | 0 | 67 |
| 10 | Dividends | (155) | (134) |
| 14 | **TOTAL OUTSIDE** | **$ 80** | **$ (33)** |
| 15 | **TOTAL SOURCES** | **$ 356** | **$ 332** |

**PECO Energy**
**REQUIREMENTS AND SOURCES OF FUNDS**
**(Millions of Dollars)**

**CASH FLOW DETAIL**

| | | Year 2015 | Year 2016 |
|---|---|---|---|
| | **CAPITAL REQUIREMENTS** | | |
| 1 | Capital Expenditures | $ 563 | $ 530 |
| 2 | **Cash used in Investing** | **$ 563** | **$ 530** |
| | **SOURCES** | | |
| | **OPERATING ACTIVITIES** | | |
| 3 | Net Income | $ 324 | $ 315 |
| 4 | Depreciation & Amortization | 262 | 276 |
| 5 | Change in Deferred Taxes | 11 | 15 |
| 6 | Change in Working Capital | (104) | 27 |
| 7 | **TOTAL INTERNAL** | **$ 493** | **$ 634** |
| | **FINANCING ACTIVITIES** | | |
| 8 | Change in Total Long-Term Debt | $ 350 | $ 50 |
| 9 | Securitization | - | - |
| 10 | Change in Total Notes Payable | - | 100 |
| 11 | Parent Receivable | - | - |
| 12 | Total Dividends | (281) | (254) |
| 13 | **TOTAL OUTSIDE** | **$ 69** | **$ (104)** |
| 14 | **TOTAL SOURCES** | **$ 563** | **$ 530** |

Q. III-F-3 State what coverage requirements or capital structure ratios are required in the most restrictive of applicable indentures/charter tests and how these measures have been computed.

A. III-F-3 There are no indenture provisions that impose coverage requirements or capital structure requirements. The credit agreement for the Company's revolving credit facilities require that it maintain a ratio of 2.0 to 1.0 for cash from operations to interest expense for the twelve-month periods ended on the last day of any quarter. The interest coverage ratio excludes revenues and interest expenses attributable to securitization debt, certain changes in working capital, and distributions on preferred securities of subsidiaries and interest on nonrecourse debt. The Company'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 the Company 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 stock. The Company currently has no outstanding preferred stock.

Q. III-F-4 A schedule of comparative financial data shall be supplied for the test year, the most immediately available annual historical period, prior to the test year, and the 2 calendar years most immediately preceding the test year. Changes in Moody's/S&P ratings, noted on this schedule, shall be accompanied by the Moody's/S&P write-up of such change, if available. The following financial data and ratios shall be supplied for the utility's parent, where applicable, if not available for the utility.

a. Times interest earned ratio – pre- and post-tax basis.
b. Preferred stock dividend coverage ratio – post-tax basis.
c. Times fixed charges earned ratio – pre-tax basis.
d. Earnings per share
e. Dividend per share
f. Average dividend yield (52-week high/low common stock price)
g. Average book value per share
h. Average market price per share
i. Market price-book value per ratio
j. Earnings-book value ratio (per share basis, average book value)
k. Dividend payout ratio
l. AFUDC as a percent of earnings available for common equity.
m. Construction work in progress as a percent of net utility plant.
n. Effective income tax rate.
o. Internal cash generations as a percent of total capital requirements.

A. III-F-4 a. Times interest earned ratio – pre and post tax basis:

Refer to Exhibits SY-1 and 2 for the fully projected future test year (FPFTY) and the future test year (FTY), respectively.. Refer to SDR-ROR-23a for the preceding calendar years.

b. Preferred stock dividend coverage ratio – post-tax basis:

Refer to Exhibits SY-1 and 2 for the FPFTY and FTY, respectively. Refer to SDR-ROR-23b for the preceding calendar years.

c. Times fixed charges earned ratio – pre tax basis:

Refer to Exhibits SY-1 and 2 for the FPFTY and the FTY, respectively. Refer to SDR-ROR-23c for the preceding calendar years.

d. Earnings per share:

Refer to Exhibits SY-1 and 2 for FPFTY and FTY, respectively.

| | **PECO Energy Consolidated (SEC)** |
|---|---|
| **2013** | $ 2.32 |
| **2014** | $2.07 |

e. Dividend per share:

| | **PECO Energy Consolidated (SEC)** |
|---|---|
| **2013** | $ 1.95 |
| **2014** | $1.88 |

f. Average dividend yield (52-week high/low common stock price):

| | **Exelon Corporation (SEC)** |
|---|---|
| **2013** | 4.53% |
| **2014** | 3.79% |

g. Average book value per share:

| | PECO Energy Consolidated (SEC) |
|---|---|
| **2013** | $18.03 |
| **2014** | $18.36 |

h. Average market price per share:

| | Exelon Corporation (SEC) |
|---|---|
| **2013** | $ 32.22 |
| **2014** | $32.69 |

i. Market price-book value ratio:

| | Exelon Corporation (SEC) |
|---|---|
| **2013** | 1.03 |
| **2014** | 1.37 |

j. Earnings-book value ratio (per share basis, average book value):

| | PECO Energy Consolidated (SEC) |
|---|---|
| **2013** | 0.13 |
| **2014** | 0.11 |

k. Dividend payout ratio:

Refer to Exhibits SY-1 and 2 for the FPFTY and FTY, respectively. Refer to SDR-ROR-23d for the preceding calendar years.

l. AFUDC as a percent of earnings available for common equity:

   Refer to Exhibits SY-1 and 2 for the FPFTY and FTY, respectively. Refer to SDR-ROR-23e for the preceding calendar years.

m. Construction work in progress as a percent of net utility plant:

   Refer to Exhibits SY-1 and 2 for the FPFTY and FTY, respectively. Refer to SDR-ROR-23f for the preceding calendar years.

n. Effective income tax rate:

   Refer to Exhibits SY-1 and 2 for the FPFTY and FTY, respectively. Refer to SDR-ROR-23g for the preceding calendar years.

o. Internal cash generation as a percent of total capital requirements:

   Refer to Exhibits SY-1 & 2 for FPFTY and FTY, respectively. Refer to SDR-ROR-23h for the preceding calendar years.

Changes in Moody's, S&P & Fitch Ratings for PECO

## MOODY'S INVESTOR SERVICES

On January 30, 2014 Moody's upgraded PECO's issuer and senior unsecured debt rating to A2 from A3, PECO's senior secured debt rating to AA3 from A1 and PECO's short-term rating to P1 from P2. PECO's long-term debt and short-term ratings were placed on stable outlook.

**PECO Energy Company**
Credit Ratings

| | 2014 | 2013 |
|---|---|---|
| **Moody's Investors Services:** | | |
| Issuer Rating | A2 | A3 |
| Senior unsecured debt | A2 | A3 |
| Senior secured debt | AA3 | A1 |
| Short term rating | P1 | P2 |
| | | |
| **Standard & Poor's Rating Group:** | | |
| Corporate Credit Rating | BBB | BBB |
| Senior unsecured debt | NR | NR |
| Senior secured debt | A- | A- |
| | | |
| **Fitch Ratings:** | | |
| Issuer Default Ratings | BBB+ | BBB+ |
| Senior unsecured debt | A- | A- |
| Senior secured debt | A | A |

Q. IV-A-1 Provide a summary schedule of the individual rate effects. For each state jurisdictional rate, show the following information for the test period elected:
Rate schedule designation.

A. IV-A-1 Attachment IV-A-1(a) provides the requested information for IV-A-1, IV-A-2, IV-A-3, and IV-A-5.

**PECO Energy Company**
**Base Revenue 12 Months Ending December 31, 2016**
**($000)**

| Lines | Description | Residential | Residential Heating | General Service | Primary Distribution | High Tension | Electric Propulsion | Lighting | Total |
|---|---|---|---|---|---|---|---|---|---|
| 1 | Customers Numbers | 1,264,324 | 180,200 | 149,681 | 500 | 2,605 | 39 | 12,495 | 1,609,844 |
| 2 | Delivery kWh | 10,686,495,987 | 2,773,930,000 | 7,915,759,254 | 510,946,108 | 15,249,248,337 | 747,600,000 | 206,011,181 | 38,089,990,867 |
| 3 | Budget Revenue | $ 1,244,262 | $ 276,581 | $ 377,966 | $ 12,019 | $ 217,329 | $ 11,416 | $ 22,522 | $ 2,162,094 |
| 4 | State Tax Adjustment | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 5 | Less: Commodity | $ (514,041) | $ (129,093) | $ (126,386) | $ (888) | $ (26,512) | $ - | $ (1,423) | $ (798,344) |
| 6 | Total T&D | $ 730,220 | $ 147,488 | $ 251,579 | $ 11,131 | $ 190,817 | $ 11,416 | $ 21,099 | $ 1,363,751 |
| 7 | Less: Retail Transmission Revenue | $ (59,378) | $ (11,727) | $ (30,291) | $ (873) | $ (24,337) | $ (1,115) | $ (76) | $ (127,798) |
| 8 | Less: Act 129 Adjustments | $ (7,933) | $ (2,059) | $ (3,250) | $ (62) | $ (1,841) | $ - | $ (509) | $ (15,654) |
| 9 | Less: EE | $ (27,222) | $ (8,842) | $ (17,591) | $ (928) | $ (23,135) | $ (1,593) | $ (637) | $ (79,948) |
| 10 | Less: CAP | $ 148 | $ 12 | | | | | | $ 160 |
| 11 | Plus: Tax Repair Catch-up Adjustment | $ 9,618 | $ 2,497 | $ 4,737 | $ 122 | $ 3,031 | | | $ 20,003 |
| 12 | Plus: Annualization & Leap Year Adjustment | $ 371 | $ 96 | $ 86 | $ (2) | $ (55) | $ (4) | $ - | $ 492 |
| 13 | Total Base Revenue @ Current Rate | $ 645,824 | $ 127,465 | $ 205,270 | $ 9,388 | $ 144,479 | $ 8,703 | $ 19,876 | $ 1,161,006 |
| 14 | Updated Commodity using PTC(1) | $ 845,775 | $ 220,273 | $ 623,529 | $ 34,888 | $ 1,041,228 | $ 51,047 | $ 15,224 | $ 2,831,963 |
| 15 | Transmission(1) | $ 79,732 | $ 17,303 | $ 74,833 | $ 2,920 | $ 87,135 | $ 4,272 | $ 242 | $ 266,438 |
| 16 | Total Bill with @ Current Rate | $ 1,571,332 | $ 365,041 | $ 903,633 | $ 47,196 | $ 1,272,842 | $ 64,021 | $ 35,343 | $ 4,259,407 |
| 17 | Proposed Base Revenue | $ 1,670,157 | $ 391,047 | $ 945,449 | $ 48,865 | $ 1,294,974 | $ 65,689 | $ 36,235 | $ 4,452,415 |
| 18 | Adjustment to PTC for Working Capital | $ (1,670) | $ (403) | $ (591) | $ (7) | $ (243) | $ (11) | $ (4) | $ (2,929) |
| 19 | State Tax Adjustment | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 20 | Total Revenue @ Proposed Rate | $ 1,668,487 | $ 390,644 | $ 944,858 | $ 48,858 | $ 1,294,731 | $ 65,678 | $ 36,231 | $ 4,449,486 |
| 21 | Proposed Increase | $ 97,155 | $ 25,603 | $ 41,225 | $ 1,662 | $ 21,889 | $ 1,657 | $ 888 | $ 190,079 |
| 22 | % of Total Increase [Line 21/(Line 16-Line 9-Line 11)] | 6.1% | 6.9% | 4.5% | 3.5% | 1.7% | 2.5% | 2.5% | 4.4% |
| 23 | % of Distribution Increase [Line 21/(Line 13-Line 9-Line 11)] | 14.6% | 19.1% | 18.9% | 16.3% | 13.3% | 16.1% | 4.3% | 15.6% |

Note:
1. Assuming no shopping for purpose of calculation

Q. IV-A-2 Provide a summary schedule of the individual rate effects. For each state jurisdictional rate, show the following information for the test period elected:

For existing rates:

(a) Customers served as of end of period.
(b) Annual Kwh sales.
(c) Base rate revenues adjusted for any changes in base rate application that may have occurred during the test period.
(d) Tax surcharge revenues.
(e) Energy Cost adjustment clause revenues.
(f) Revenues received from other clauses or riders separately accounted for.
(g) Total of all revenues.

A. IV-A-2 Refer to the response to IV-A-1(a).

Q. IV-A-3 Provide a summary schedule of the individual rate effects. For each state jurisdictional rate, show the following information for the test period elected. For proposed rates:

(a) Estimated number of customers whose charged for electric service will be increased or decreased as a result of this filing.
(b) Base rate revenues:
  (1) Annual dollar amount of increase or decrease.
  (2) Percentage change.
(c) Estimated tax surcharge revenues based on the assumption that the base rate changes proposed were in place.
(d) Estimated Energy cost adjustment clause revenues.
(e) Revenues received from other clauses or riders separately accounted for.
(f) Total of all revenues:
  (1) Amount of total annual dollar change.
  (2) Percentage change.

A. IV-A-3 Refer to the response to IV-A-1(a).

Q. IV-A-4 Supplement the revenue summary to obtain a complete revenue statement of the electric business, that is, show delayed payments, other electric revenues, FERC jurisdictional sales and revenues and all other appropriate revenue items and adjustments.

A. IV-A-4 The Company's sales forecast is based on budgeted sales for the future test year (FTY) ending December 31, 2015 and fully projected future test year (FPFTY) ending December 31, 2016, as adjusted by various annualization and normalization adjustments. The budget and adjustments thereto are described in PECO Statement No. 3, the direct testimony of Shuo Yin, and are set forth in Schedule D-5 of Exhibits PECO Exhibits SY-1 and SY-2, for the FPFTY and FTY, respectively. For the Company's sales forecast refer to the responses for SDR-RR-6 and SDR-RR-7.

Q. IV-A-5 Develop the grand total sales and revenues as adjusted and the various increases and decreases and percent effects as described above.

A. IV-A-5 Refer to the response to IV-A-1(a).

Q. IV-B-1 Provide a description of changes proposed for the new tariff:

(1) For each rate schedule proposed to be modified.
(2) For each rate schedule proposed to be deleted.
(3) For each new rate schedule proposed to be added.

A. IV-B-1 Refer to PECO Statement Nos. 7 and 8, the direct testimony of Scott A. Neumann and Richard A. Schlesinger, for a description of the proposed rate changes.

Q. IV-C-1 The annual revenue effect of any proposed change to any rate must be supported by a billing analysis. This may consist of the use of bill frequency distributions or individual customer billing records for the most recent annual periods available. All billing determinants should be displayed. The blocking and corresponding prices of the existing rate and the proposed rate should be applied to the determinants to derive the base rate revenues under both present and proposed rates. The derived base rate revenues should form the basis for measuring the annual base rate effect of the rates in question for the test periods.

A. IV-C-1 Refer to PECO Statement No. 7, Exhibit SAN-7, for a proof of Revenue at proposed rates using projected billing determinants for the fully projected future test year.

Q. IV-D-1 Residential Bill Comparisons.
For each rate applicable to residential service provide a chart or tabulation which shows the dollar and percentage effect of the proposed base rate on monthly bills ranging from the use of zero kWh to 5,000 kWh at appropriate intervals.

A. IV-D-1 Refer to Attachment IV-D-1(a) for the requested information.

# PECO
## Comparison Of Monthly Bills
## Rate R Residential Service

| | Total Bill | | | | Excluding Generation & Transmission | | | |
|---|---|---|---|---|---|---|---|---|
| Kwh Usage | Existing Rate | Proposed Rate | $ Change | % Change | Existing Rate | Proposed Rate | $ Change | % Change |
| 0 | 7.11 | 11.99 | 4.88 | 68.6% | 7.11 | 11.99 | 4.88 | 68.6% |
| 50 | 14.47 | 19.47 | 5.00 | 34.6% | 10.14 | 15.15 | 5.01 | 49.4% |
| 100 | 21.83 | 26.95 | 5.12 | 23.5% | 13.17 | 18.30 | 5.13 | 39.0% |
| 150 | 29.20 | 34.43 | 5.23 | 17.9% | 16.21 | 21.46 | 5.25 | 32.4% |
| 200 | 36.56 | 41.91 | 5.35 | 14.6% | 19.24 | 24.61 | 5.37 | 27.9% |
| 250 | 43.92 | 49.39 | 5.47 | 12.5% | 22.27 | 27.77 | 5.50 | 24.7% |
| 300 | 51.28 | 56.88 | 5.60 | 10.9% | 25.30 | 30.93 | 5.63 | 22.3% |
| 350 | 58.64 | 64.36 | 5.72 | 9.8% | 28.33 | 34.09 | 5.75 | 20.3% |
| 400 | 66.01 | 71.84 | 5.83 | 8.8% | 31.37 | 37.24 | 5.87 | 18.7% |
| 450 | 73.37 | 79.32 | 5.95 | 8.1% | 34.40 | 40.40 | 6.00 | 17.4% |
| 500 | 80.73 | 86.80 | 6.07 | 7.5% | 37.43 | 43.55 | 6.12 | 16.4% |
| 550 | 88.09 | 94.28 | 6.19 | 7.0% | 40.46 | 46.71 | 6.24 | 15.4% |
| 600 | 95.45 | 101.76 | 6.31 | 6.6% | 43.49 | 49.86 | 6.37 | 14.6% |
| 650 | 102.81 | 109.25 | 6.44 | 6.3% | 46.52 | 53.03 | 6.50 | 14.0% |
| 700 | 110.18 | 116.73 | 6.55 | 5.9% | 49.56 | 56.18 | 6.62 | 13.4% |
| 750 | 117.54 | 124.21 | 6.67 | 5.7% | 52.59 | 59.34 | 6.74 | 12.8% |
| 800 | 124.90 | 131.69 | 6.79 | 5.4% | 55.62 | 62.49 | 6.87 | 12.4% |
| 850 | 132.26 | 139.17 | 6.91 | 5.2% | 58.65 | 65.65 | 6.99 | 11.9% |
| 900 | 139.62 | 146.65 | 7.03 | 5.0% | 61.68 | 68.80 | 7.12 | 11.5% |
| 950 | 146.98 | 154.14 | 7.16 | 4.9% | 64.71 | 71.97 | 7.26 | 11.2% |
| 1000 | 154.35 | 161.62 | 7.27 | 4.7% | 67.75 | 75.12 | 7.37 | 10.9% |
| 1100 | 169.07 | 176.58 | 7.51 | 4.4% | 73.81 | 81.43 | 7.62 | 10.3% |
| 1200 | 183.79 | 191.54 | 7.75 | 4.2% | 79.87 | 87.74 | 7.87 | 9.9% |
| 1300 | 198.52 | 206.51 | 7.99 | 4.0% | 85.94 | 94.06 | 8.12 | 9.4% |
| 1400 | 213.24 | 221.47 | 8.23 | 3.9% | 92.00 | 100.37 | 8.37 | 9.1% |
| 1500 | 227.96 | 236.43 | 8.47 | 3.7% | 98.06 | 106.68 | 8.62 | 8.8% |
| 2000 | 301.58 | 311.25 | 9.67 | 3.2% | 128.38 | 138.25 | 9.87 | 7.7% |
| 5000 | 743.29 | 760.13 | 16.84 | 2.3% | 310.29 | 327.63 | 17.34 | 5.6% |

PECO
Comparison Of Monthly Bills
Rate RH Residential Heating Service - Summer

| | Total Bill | | | | Excluding Generation & Transmission | | | |
|---|---|---|---|---|---|---|---|---|
| Kwh Usage | Existing Rate | Proposed Rate | $ Change | % Change | Existing Rate | Proposed Rate | $ Change | % Change |
| 0 | 7.11 | 11.99 | 4.88 | 68.6% | 7.11 | 11.99 | 4.88 | 68.6% |
| 50 | 14.47 | 19.48 | 5.01 | 34.6% | 10.14 | 15.15 | 5.01 | 49.4% |
| 100 | 21.83 | 26.96 | 5.13 | 23.5% | 13.17 | 18.31 | 5.14 | 39.0% |
| 150 | 29.20 | 34.45 | 5.25 | 18.0% | 16.21 | 21.47 | 5.26 | 32.4% |
| 200 | 36.56 | 41.93 | 5.37 | 14.7% | 19.24 | 24.63 | 5.39 | 28.0% |
| 250 | 43.92 | 49.42 | 5.50 | 12.5% | 22.27 | 27.79 | 5.52 | 24.8% |
| 300 | 51.28 | 56.91 | 5.63 | 11.0% | 25.30 | 30.96 | 5.66 | 22.4% |
| 350 | 58.64 | 64.40 | 5.76 | 9.8% | 28.33 | 34.12 | 5.79 | 20.4% |
| 400 | 66.01 | 71.88 | 5.87 | 8.9% | 31.37 | 37.28 | 5.91 | 18.8% |
| 450 | 73.37 | 79.37 | 5.99 | 8.2% | 34.40 | 40.44 | 6.04 | 17.6% |
| 500 | 80.73 | 86.85 | 6.12 | 7.6% | 37.43 | 43.60 | 6.17 | 16.5% |
| 550 | 88.09 | 94.34 | 6.25 | 7.1% | 40.46 | 46.76 | 6.30 | 15.6% |
| 600 | 95.45 | 101.82 | 6.37 | 6.7% | 43.49 | 49.92 | 6.43 | 14.8% |
| 650 | 102.81 | 109.32 | 6.51 | 6.3% | 46.52 | 53.09 | 6.57 | 14.1% |
| 700 | 110.18 | 116.80 | 6.62 | 6.0% | 49.56 | 56.25 | 6.69 | 13.5% |
| 750 | 117.54 | 124.29 | 6.75 | 5.7% | 52.59 | 59.41 | 6.82 | 13.0% |
| 800 | 124.90 | 131.77 | 6.87 | 5.5% | 55.62 | 62.57 | 6.95 | 12.5% |
| 850 | 132.26 | 139.26 | 6.99 | 5.3% | 58.65 | 65.73 | 7.08 | 12.1% |
| 900 | 139.62 | 146.74 | 7.12 | 5.1% | 61.68 | 68.89 | 7.21 | 11.7% |
| 950 | 146.98 | 154.23 | 7.25 | 4.9% | 64.71 | 72.05 | 7.34 | 11.3% |
| 1000 | 154.35 | 161.72 | 7.37 | 4.8% | 67.75 | 75.22 | 7.47 | 11.0% |
| 1100 | 169.07 | 176.69 | 7.62 | 4.5% | 73.81 | 81.54 | 7.73 | 10.5% |
| 1200 | 183.79 | 191.66 | 7.87 | 4.3% | 79.87 | 87.86 | 7.99 | 10.0% |
| 1300 | 198.52 | 206.64 | 8.12 | 4.1% | 85.94 | 94.19 | 8.25 | 9.6% |
| 1400 | 213.24 | 221.61 | 8.37 | 3.9% | 92.00 | 100.51 | 8.51 | 9.2% |
| 1500 | 227.96 | 236.58 | 8.62 | 3.8% | 98.06 | 106.83 | 8.77 | 8.9% |
| 2000 | 301.58 | 311.45 | 9.87 | 3.3% | 128.38 | 138.45 | 10.07 | 7.8% |
| 2500 | 375.20 | 386.31 | 11.11 | 3.0% | 158.70 | 170.06 | 11.36 | 7.2% |
| 3000 | 448.82 | 461.17 | 12.35 | 2.8% | 189.02 | 201.67 | 12.65 | 6.7% |
| 5000 | 743.29 | 760.63 | 17.34 | 2.3% | 310.29 | 328.13 | 17.84 | 5.7% |

# PECO
## Comparison Of Monthly Bills
## Rate RH Residential Heating Service - Winter

| | Total Bill | | | | Excluding Generation & Transmission | | | |
|---|---|---|---|---|---|---|---|---|
| Kwh Usage | Existing Rate | Proposed Rate | $ Change | % Change | Existing Rate | Proposed Rate | $ Change | % Change |
| 0 | 7.11 | 11.99 | 4.88 | 68.6% | 7.11 | 11.99 | 4.88 | 68.6% |
| 50 | 13.51 | 18.70 | 5.19 | 38.4% | 9.18 | 14.38 | 5.20 | 56.6% |
| 100 | 19.90 | 25.41 | 5.51 | 27.7% | 11.24 | 16.76 | 5.52 | 49.1% |
| 150 | 26.29 | 32.13 | 5.84 | 22.2% | 13.30 | 19.16 | 5.86 | 44.0% |
| 200 | 32.69 | 38.84 | 6.15 | 18.8% | 15.37 | 21.54 | 6.17 | 40.1% |
| 250 | 39.08 | 45.56 | 6.48 | 16.6% | 17.43 | 23.94 | 6.51 | 37.3% |
| 300 | 45.48 | 52.27 | 6.79 | 14.9% | 19.50 | 26.32 | 6.82 | 35.0% |
| 350 | 51.87 | 58.98 | 7.11 | 13.7% | 21.56 | 28.71 | 7.15 | 33.1% |
| 400 | 58.27 | 65.70 | 7.43 | 12.8% | 23.63 | 31.10 | 7.47 | 31.6% |
| 450 | 64.66 | 72.41 | 7.75 | 12.0% | 25.69 | 33.49 | 7.80 | 30.3% |
| 500 | 71.05 | 79.12 | 8.07 | 11.4% | 27.75 | 35.87 | 8.12 | 29.3% |
| 550 | 77.45 | 85.84 | 8.39 | 10.8% | 29.82 | 38.27 | 8.44 | 28.3% |
| 600 | 83.84 | 92.55 | 8.71 | 10.4% | 31.88 | 40.65 | 8.77 | 27.5% |
| 650 | 90.24 | 99.26 | 9.02 | 10.0% | 33.95 | 43.04 | 9.09 | 26.8% |
| 700 | 96.63 | 105.98 | 9.35 | 9.7% | 36.01 | 45.43 | 9.42 | 26.2% |
| 750 | 103.03 | 112.69 | 9.66 | 9.4% | 38.08 | 47.82 | 9.73 | 25.6% |
| 800 | 109.42 | 119.40 | 9.98 | 9.1% | 40.14 | 50.20 | 10.06 | 25.1% |
| 850 | 115.82 | 126.12 | 10.30 | 8.9% | 42.21 | 52.60 | 10.39 | 24.6% |
| 900 | 122.21 | 132.83 | 10.62 | 8.7% | 44.27 | 54.98 | 10.71 | 24.2% |
| 950 | 128.60 | 139.54 | 10.94 | 8.5% | 46.33 | 57.37 | 11.04 | 23.8% |
| 1000 | 135.00 | 146.26 | 11.26 | 8.3% | 48.40 | 59.76 | 11.36 | 23.5% |
| 1500 | 198.94 | 213.39 | 14.45 | 7.3% | 69.04 | 83.64 | 14.60 | 21.1% |
| 2000 | 262.89 | 280.53 | 17.64 | 6.7% | 89.69 | 107.53 | 17.84 | 19.9% |
| 2350 | 307.65 | 327.52 | 19.87 | 6.5% | 104.14 | 124.25 | 20.11 | 19.3% |
| 2500 | 326.83 | 347.66 | 20.83 | 6.4% | 110.33 | 131.41 | 21.08 | 19.1% |
| 3300 | 429.14 | 455.08 | 25.94 | 6.0% | 143.36 | 169.63 | 26.27 | 18.3% |
| 4000 | 518.66 | 549.07 | 30.41 | 5.9% | 172.26 | 203.07 | 30.81 | 17.9% |
| 4500 | 582.61 | 616.21 | 33.60 | 5.8% | 192.91 | 226.96 | 34.05 | 17.7% |
| 5000 | 646.55 | 683.34 | 36.79 | 5.7% | 213.55 | 250.84 | 37.29 | 17.5% |

Q. IV-D-2 General Bill Comparisons.
For each rate that requires both a billing a demand (kW) and kWh's as the billing determinants, provide a tabulation or graphical comparison showing the percentage effect of the proposed base rate on monthly bills using several representative demand (kW) levels, the monthly kWh for each demand selected to be in load factor increments of 10% starting at 0% and ending at 100% (730H) or by hours' use increments that covers approximately 95% of the bills.

A. IV-D-2 Refer to Attachment IV-D-2(a) for the requested information.

# PECO
## Comparison of Monthly Bills
## Rate HT High Tension
## Demand = 50000 kW

| | Total Bill | | | | Excluding Generation & Transmission | | | |
|---|---|---|---|---|---|---|---|---|
| Hrs Usage | Existing Rate | Proposed Rate | $ Change | % Change | Existing Rate | Proposed Rate | $ Change | % Change |
| 0 | $ 86,870.94 | $ 117,388.19 | $ 30,517.25 | 35% | $ 86,870.94 | $ 117,388.19 | $ 30,517.25 | 35% |
| 50 | $ 508,209.28 | $ 580,264.07 | $ 72,054.79 | 14% | $ 220,459.28 | $ 292,514.07 | $ 72,054.79 | 33% |
| 100 | $ 697,699.15 | $ 765,515.42 | $ 67,816.27 | 10% | $ 224,199.15 | $ 292,015.42 | $ 67,816.27 | 30% |
| 150 | $ 887,189.03 | $ 950,766.77 | $ 63,577.74 | 7% | $ 227,939.03 | $ 291,516.77 | $ 63,577.74 | 28% |
| 200 | $ 1,076,678.90 | $ 1,136,018.12 | $ 59,339.22 | 6% | $ 231,678.90 | $ 291,018.12 | $ 59,339.22 | 26% |
| 250 | $ 1,266,168.78 | $ 1,321,269.47 | $ 55,100.69 | 4% | $ 235,418.78 | $ 290,519.47 | $ 55,100.69 | 23% |
| 300 | $ 1,455,658.65 | $ 1,506,520.82 | $ 50,862.17 | 3% | $ 239,158.65 | $ 290,020.82 | $ 50,862.17 | 21% |
| 400 | $ 1,834,638.40 | $ 1,877,023.52 | $ 42,385.12 | 2% | $ 246,638.40 | $ 289,023.52 | $ 42,385.12 | 17% |
| 500 | $ 2,213,618.15 | $ 2,247,526.22 | $ 33,908.07 | 2% | $ 254,118.15 | $ 288,026.22 | $ 33,908.07 | 13% |
| 600 | $ 2,592,597.90 | $ 2,618,028.92 | $ 25,431.02 | 1% | $ 261,597.90 | $ 287,028.92 | $ 25,431.02 | 10% |
| 700 | $ 2,971,577.65 | $ 2,988,531.62 | $ 16,953.97 | 1% | $ 269,077.65 | $ 286,031.62 | $ 16,953.97 | 6% |
| 730 | $ 3,085,271.58 | $ 3,099,682.43 | $ 14,410.85 | 0% | $ 271,321.58 | $ 285,732.43 | $ 14,410.85 | 5% |

# PECO
## Comparison of Monthly Bills
## Rate HT High Tension
## Demand = 1300 kW

| | Total Bill | | | | Excluding Generation & Transmission | | | |
|---|---|---|---|---|---|---|---|---|
| Hrs Usage | Existing Rate | Proposed Rate | $ Change | % Change | Existing Rate | Proposed Rate | $ Change | % Change |
| 0 | $ 2,036.62 | $ 3,349.33 | $ 1,312.71 | 64% | $ 2,036.62 | $ 3,349.33 | $ 1,312.71 | 64% |
| 50 | $ 11,600.32 | $ 15,384.11 | $ 3,783.79 | 33% | $ 4,730.82 | $ 7,902.61 | $ 3,171.79 | 67% |
| 100 | $ 16,527.06 | $ 20,200.64 | $ 3,673.58 | 22% | $ 4,828.06 | $ 7,889.64 | $ 3,061.58 | 63% |
| 150 | $ 21,453.80 | $ 25,017.18 | $ 3,563.38 | 17% | $ 4,925.30 | $ 7,876.68 | $ 2,951.38 | 60% |
| 200 | $ 26,380.53 | $ 29,833.71 | $ 3,453.18 | 13% | $ 5,022.53 | $ 7,863.71 | $ 2,841.18 | 57% |
| 250 | $ 31,307.27 | $ 34,650.25 | $ 3,342.98 | 11% | $ 5,119.77 | $ 7,850.75 | $ 2,730.98 | 53% |
| 300 | $ 36,234.01 | $ 39,466.78 | $ 3,232.77 | 9% | $ 5,217.01 | $ 7,837.78 | $ 2,620.77 | 50% |
| 400 | $ 46,087.48 | $ 49,099.85 | $ 3,012.37 | 7% | $ 5,411.48 | $ 7,811.85 | $ 2,400.37 | 44% |
| 500 | $ 55,940.95 | $ 58,732.92 | $ 2,791.97 | 5% | $ 5,605.95 | $ 7,785.92 | $ 2,179.97 | 39% |
| 600 | $ 65,794.43 | $ 68,365.99 | $ 2,571.56 | 4% | $ 5,800.43 | $ 7,759.99 | $ 1,959.56 | 34% |
| 700 | $ 75,647.90 | $ 77,999.06 | $ 2,351.16 | 3% | $ 5,994.90 | $ 7,734.06 | $ 1,739.16 | 29% |
| 730 | $ 78,603.94 | $ 80,888.98 | $ 2,285.04 | 3% | $ 6,053.24 | $ 7,726.28 | $ 1,673.04 | 28% |

# PECO
## Comparison of Monthly Bills
## Rate HT High Tension
## Demand = 500 kW

| | Total Bill | | | | Excluding Generation & Transmission | | | |
|---|---|---|---|---|---|---|---|---|
| Hrs Usage | Existing Rate | Proposed Rate | $ Change | % Change | Existing Rate | Proposed Rate | $ Change | % Change |
| 0 | $ 1,170.96 | $ 1,476.00 | $ 305.04 | 26% | $ 1,170.96 | $ 1,476.00 | $ 305.04 | 26% |
| 50 | $ 5,384.34 | $ 6,104.76 | $ 720.42 | 13% | $ 2,506.84 | $ 3,227.26 | $ 720.42 | 29% |
| 100 | $ 7,279.24 | $ 7,957.28 | $ 678.04 | 9% | $ 2,544.24 | $ 3,222.28 | $ 678.04 | 27% |
| 150 | $ 9,174.14 | $ 9,809.79 | $ 635.65 | 7% | $ 2,581.64 | $ 3,217.29 | $ 635.65 | 25% |
| 200 | $ 11,069.04 | $ 11,662.30 | $ 593.26 | 5% | $ 2,619.04 | $ 3,212.30 | $ 593.26 | 23% |
| 250 | $ 12,963.94 | $ 13,514.82 | $ 550.88 | 4% | $ 2,656.44 | $ 3,207.32 | $ 550.88 | 21% |
| 300 | $ 14,858.84 | $ 15,367.33 | $ 508.49 | 3% | $ 2,693.84 | $ 3,202.33 | $ 508.49 | 19% |
| 400 | $ 18,648.63 | $ 19,072.36 | $ 423.73 | 2% | $ 2,768.63 | $ 3,192.36 | $ 423.73 | 15% |
| 500 | $ 22,438.43 | $ 22,777.38 | $ 338.95 | 2% | $ 2,843.43 | $ 3,182.38 | $ 338.95 | 12% |
| 600 | $ 26,228.23 | $ 26,482.41 | $ 254.18 | 1% | $ 2,918.23 | $ 3,172.41 | $ 254.18 | 9% |
| 700 | $ 30,018.03 | $ 30,187.44 | $ 169.41 | 1% | $ 2,993.03 | $ 3,162.44 | $ 169.41 | 6% |
| 730 | $ 31,154.97 | $ 31,298.95 | $ 143.98 | 0% | $ 3,015.47 | $ 3,159.45 | $ 143.98 | 5% |

# PECO
## Comparison of Monthly Bills
## Rate HT High Tension
## Demand = 100 kW

| | Total Bill | | | | Excluding Generation & Transmission | | | |
|---|---|---|---|---|---|---|---|---|
| Hrs Usage | Existing Rate | Proposed Rate | $ Change | % Change | Existing Rate | Proposed Rate | $ Change | % Change |
| 0 | $ 478.43 | $ 539.34 | $ 60.91 | 13% | $ 478.43 | $ 539.34 | $ 60.91 | 13% |
| 50 | $ 1,314.61 | $ 1,458.59 | $ 143.98 | 11% | $ 745.61 | $ 889.59 | $ 143.98 | 19% |
| 100 | $ 1,687.09 | $ 1,822.59 | $ 135.50 | 8% | $ 753.09 | $ 888.59 | $ 135.50 | 18% |
| 150 | $ 2,059.57 | $ 2,186.60 | $ 127.03 | 6% | $ 760.57 | $ 887.60 | $ 127.03 | 17% |
| 200 | $ 2,432.05 | $ 2,550.60 | $ 118.55 | 5% | $ 768.05 | $ 886.60 | $ 118.55 | 15% |
| 250 | $ 2,804.53 | $ 2,914.60 | $ 110.07 | 4% | $ 775.53 | $ 885.60 | $ 110.07 | 14% |
| 300 | $ 3,177.01 | $ 3,278.61 | $ 101.60 | 3% | $ 783.01 | $ 884.61 | $ 101.60 | 13% |
| 400 | $ 3,921.97 | $ 4,006.61 | $ 84.64 | 2% | $ 797.97 | $ 882.61 | $ 84.64 | 11% |
| 500 | $ 4,666.93 | $ 4,734.62 | $ 67.69 | 1% | $ 812.93 | $ 880.62 | $ 67.69 | 8% |
| 600 | $ 5,411.89 | $ 5,462.62 | $ 50.73 | 1% | $ 827.89 | $ 878.62 | $ 50.73 | 6% |
| 700 | $ 6,156.85 | $ 6,190.63 | $ 33.78 | 1% | $ 842.85 | $ 876.63 | $ 33.78 | 4% |
| 730 | $ 6,380.34 | $ 6,409.03 | $ 28.69 | 0% | $ 847.34 | $ 876.03 | $ 28.69 | 3% |

# PECO
## Comparison of Monthly Bills
## Rate PD Primary Distribution Power
## Demand = 500 kW

| | Total Bill | | | | Excluding Generation & Transmission | | | |
|---|---|---|---|---|---|---|---|---|
| Hrs Usage | Existing Rate | Proposed Rate | $ Change | % Change | Existing Rate | Proposed Rate | $ Change | % Change |
| 0 | $ 1,394.06 | $ 1,900.85 | $ 506.79 | 36% | $ 1,394.06 | $ 1,900.85 | $ 506.79 | 36% |
| 50 | $ 6,060.42 | $ 7,253.36 | $ 1,192.94 | 20% | $ 3,105.42 | $ 4,298.36 | $ 1,192.94 | 38% |
| 100 | $ 8,070.22 | $ 9,183.38 | $ 1,113.16 | 14% | $ 3,180.22 | $ 4,293.38 | $ 1,113.16 | 35% |
| 150 | $ 10,080.02 | $ 11,113.39 | $ 1,033.37 | 10% | $ 3,255.02 | $ 4,288.39 | $ 1,033.37 | 32% |
| 200 | $ 12,089.82 | $ 13,043.40 | $ 953.58 | 8% | $ 3,329.82 | $ 4,283.40 | $ 953.58 | 29% |
| 250 | $ 14,099.61 | $ 14,973.42 | $ 873.81 | 6% | $ 3,404.61 | $ 4,278.42 | $ 873.81 | 26% |
| 300 | $ 16,109.41 | $ 16,903.43 | $ 794.02 | 5% | $ 3,479.41 | $ 4,273.43 | $ 794.02 | 23% |
| 400 | $ 20,129.01 | $ 20,763.46 | $ 634.45 | 3% | $ 3,629.01 | $ 4,263.46 | $ 634.45 | 17% |
| 500 | $ 24,148.60 | $ 24,623.48 | $ 474.88 | 2% | $ 3,778.60 | $ 4,253.48 | $ 474.88 | 13% |
| 600 | $ 28,168.20 | $ 28,483.51 | $ 315.31 | 1% | $ 3,928.20 | $ 4,243.51 | $ 315.31 | 8% |
| 700 | $ 32,187.79 | $ 32,343.54 | $ 155.75 | 0% | $ 4,077.79 | $ 4,233.54 | $ 155.75 | 4% |
| 730 | $ 33,393.67 | $ 33,501.55 | $ 107.88 | 0% | $ 4,122.67 | $ 4,230.55 | $ 107.88 | 3% |

# PECO
## Comparison of Monthly Bills
## Rate PD Primary Distribution Power
## Demand = 175 kW

| | Total Bill | | | | Excluding Generation & Transmission | | | |
|---|---|---|---|---|---|---|---|---|
| Hrs Usage | Existing Rate | Proposed Rate | $ Change | % Change | Existing Rate | Proposed Rate | $ Change | % Change |
| 0 | $ 684.88 | $ 859.77 | $ 174.89 | 26% | $ 684.88 | $ 859.77 | $ 174.89 | 26% |
| 50 | $ 2,318.10 | $ 2,733.15 | $ 415.05 | 18% | $ 1,283.85 | $ 1,698.90 | $ 415.05 | 32% |
| 100 | $ 3,021.53 | $ 3,408.66 | $ 387.13 | 13% | $ 1,310.03 | $ 1,697.16 | $ 387.13 | 30% |
| 150 | $ 3,724.96 | $ 4,084.16 | $ 359.20 | 10% | $ 1,336.21 | $ 1,695.41 | $ 359.20 | 27% |
| 200 | $ 4,428.39 | $ 4,759.66 | $ 331.27 | 7% | $ 1,362.39 | $ 1,693.66 | $ 331.27 | 24% |
| 250 | $ 5,131.82 | $ 5,435.17 | $ 303.35 | 6% | $ 1,388.57 | $ 1,691.92 | $ 303.35 | 22% |
| 300 | $ 5,835.25 | $ 6,110.67 | $ 275.42 | 5% | $ 1,414.75 | $ 1,690.17 | $ 275.42 | 19% |
| 400 | $ 7,242.11 | $ 7,461.68 | $ 219.57 | 3% | $ 1,467.11 | $ 1,686.68 | $ 219.57 | 15% |
| 500 | $ 8,648.97 | $ 8,812.69 | $ 163.72 | 2% | $ 1,519.47 | $ 1,683.19 | $ 163.72 | 11% |
| 600 | $ 10,055.82 | $ 10,163.70 | $ 107.88 | 1% | $ 1,571.82 | $ 1,679.70 | $ 107.88 | 7% |
| 700 | $ 11,462.68 | $ 11,514.71 | $ 52.03 | 0% | $ 1,624.18 | $ 1,676.21 | $ 52.03 | 3% |
| 730 | $ 11,884.74 | $ 11,920.01 | $ 35.27 | 0% | $ 1,639.89 | $ 1,675.16 | $ 35.27 | 2% |

# PECO
## Comparison of Monthly Bills
## Rate PD Primary Distribution Power
## Demand = 125 kW

| | Total Bill | | | | Excluding Generation & Transmission | | | |
|---|---|---|---|---|---|---|---|---|
| Hrs Usage | Existing Rate | Proposed Rate | $ Change | % Change | Existing Rate | Proposed Rate | $ Change | % Change |
| 0 | $ 575.77 | $ 699.61 | $ 123.84 | 22% | $ 575.77 | $ 699.61 | $ 123.84 | 22% |
| 50 | $ 1,742.36 | $ 2,037.73 | $ 295.37 | 17% | $ 1,003.61 | $ 1,298.98 | $ 295.37 | 29% |
| 100 | $ 2,244.81 | $ 2,520.24 | $ 275.43 | 12% | $ 1,022.31 | $ 1,297.74 | $ 275.43 | 27% |
| 150 | $ 2,747.26 | $ 3,002.74 | $ 255.48 | 9% | $ 1,041.01 | $ 1,296.49 | $ 255.48 | 25% |
| 200 | $ 3,249.71 | $ 3,485.24 | $ 235.53 | 7% | $ 1,059.71 | $ 1,295.24 | $ 235.53 | 22% |
| 250 | $ 3,752.16 | $ 3,967.75 | $ 215.59 | 6% | $ 1,078.41 | $ 1,294.00 | $ 215.59 | 20% |
| 300 | $ 4,254.61 | $ 4,450.25 | $ 195.64 | 5% | $ 1,097.11 | $ 1,292.75 | $ 195.64 | 18% |
| 400 | $ 5,259.51 | $ 5,415.26 | $ 155.75 | 3% | $ 1,134.51 | $ 1,290.26 | $ 155.75 | 14% |
| 500 | $ 6,264.41 | $ 6,380.26 | $ 115.85 | 2% | $ 1,171.91 | $ 1,287.76 | $ 115.85 | 10% |
| 600 | $ 7,269.31 | $ 7,345.27 | $ 75.96 | 1% | $ 1,209.31 | $ 1,285.27 | $ 75.96 | 6% |
| 700 | $ 8,274.20 | $ 8,310.28 | $ 36.08 | 0% | $ 1,246.70 | $ 1,282.78 | $ 36.08 | 3% |
| 730 | $ 8,575.67 | $ 8,599.78 | $ 24.11 | 0% | $ 1,257.92 | $ 1,282.03 | $ 24.11 | 2% |

# PECO
## Comparison of Monthly Bills
## Rate PD Primary Distribution Power
## Demand = 50 kW

| | Total Bill | | | | Excluding Generation & Transmission | | | |
|---|---|---|---|---|---|---|---|---|
| Hrs Usage | Existing Rate | Proposed Rate | $ Change | % Change | Existing Rate | Proposed Rate | $ Change | % Change |
| 0 | $ 412.11 | $ 459.36 | $ 47.25 | 11% | $ 412.11 | $ 459.36 | $ 47.25 | 11% |
| 50 | $ 875.25 | $ 991.11 | $ 115.86 | 13% | $ 583.25 | $ 699.11 | $ 115.86 | 20% |
| 100 | $ 1,072.73 | $ 1,180.61 | $ 107.88 | 10% | $ 590.73 | $ 698.61 | $ 107.88 | 18% |
| 150 | $ 1,270.21 | $ 1,370.11 | $ 99.90 | 8% | $ 598.21 | $ 698.11 | $ 99.90 | 17% |
| 200 | $ 1,467.69 | $ 1,559.61 | $ 91.92 | 6% | $ 605.69 | $ 697.61 | $ 91.92 | 15% |
| 250 | $ 1,665.17 | $ 1,749.11 | $ 83.94 | 5% | $ 613.17 | $ 697.11 | $ 83.94 | 14% |
| 300 | $ 1,862.65 | $ 1,938.61 | $ 75.96 | 4% | $ 620.65 | $ 696.61 | $ 75.96 | 12% |
| 400 | $ 2,257.61 | $ 2,317.62 | $ 60.01 | 3% | $ 635.61 | $ 695.62 | $ 60.01 | 9% |
| 500 | $ 2,652.57 | $ 2,696.62 | $ 44.05 | 2% | $ 650.57 | $ 694.62 | $ 44.05 | 7% |
| 600 | $ 3,047.53 | $ 3,075.62 | $ 28.09 | 1% | $ 665.53 | $ 693.62 | $ 28.09 | 4% |
| 700 | $ 3,442.49 | $ 3,454.62 | $ 12.13 | 0% | $ 680.49 | $ 692.62 | $ 12.13 | 2% |
| 730 | $ 3,560.98 | $ 3,568.33 | $ 7.35 | 0% | $ 684.98 | $ 692.33 | $ 7.35 | 1% |

# PECO
## Comparison of Monthly Bills
## Rate GS General Service Demand Measurement
## Demand = 100 kW

| | Total Bill | | | | Excluding Generation & Transmission | | | |
|---|---|---|---|---|---|---|---|---|
| Hrs Usage | Existing Rate | Proposed Rate | $ Change | % Change | Existing Rate | Proposed Rate | $ Change | % Change |
| 0 | $ 46.27 | $ 53.69 | $ 7.42 | 16% | $ 46.27 | $ 53.69 | $ 7.42 | 16% |
| 50 | $ 1,218.41 | $ 1,481.24 | $ 262.83 | 22% | $ 567.41 | $ 830.24 | $ 262.83 | 46% |
| 100 | $ 1,644.83 | $ 1,884.22 | $ 239.39 | 15% | $ 599.83 | $ 839.22 | $ 239.39 | 40% |
| 150 | $ 2,071.24 | $ 2,287.19 | $ 215.95 | 10% | $ 632.24 | $ 848.19 | $ 215.95 | 34% |
| 200 | $ 2,497.65 | $ 2,690.17 | $ 192.52 | 8% | $ 664.65 | $ 857.17 | $ 192.52 | 29% |
| 250 | $ 2,924.06 | $ 3,093.15 | $ 169.09 | 6% | $ 697.06 | $ 866.15 | $ 169.09 | 24% |
| 300 | $ 3,350.48 | $ 3,496.12 | $ 145.64 | 4% | $ 729.48 | $ 875.12 | $ 145.64 | 20% |
| 400 | $ 4,203.30 | $ 4,302.07 | $ 98.77 | 2% | $ 794.30 | $ 893.07 | $ 98.77 | 12% |
| 500 | $ 5,056.12 | $ 5,108.02 | $ 51.90 | 1% | $ 859.12 | $ 911.02 | $ 51.90 | 6% |
| 600 | $ 5,908.95 | $ 5,913.97 | $ 5.02 | 0% | $ 923.95 | $ 928.97 | $ 5.02 | 1% |
| 700 | $ 6,761.77 | $ 6,719.93 | $ (41.84) | -1% | $ 988.77 | $ 946.93 | $ (41.84) | -4% |
| 730 | $ 7,017.62 | $ 6,961.71 | $ (55.91) | -1% | $ 1,008.22 | $ 952.31 | $ (55.91) | -6% |

# PECO
## Comparison of Monthly Bills
## Rate GS General Service Demand Measurement
## Demand = 13 kW

| | Total Bill | | | | Excluding Generation & Transmission | | | |
|---|---|---|---|---|---|---|---|---|
| Hrs Usage | Existing Rate | Proposed Rate | $ Change | % Change | Existing Rate | Proposed Rate | $ Change | % Change |
| 0 | $ 22.64 | $ 27.86 | $ 5.22 | 23% | $ 22.64 | $ 27.86 | $ 5.22 | 23% |
| 50 | $ 168.95 | $ 204.42 | $ 35.47 | 21% | $ 85.23 | $ 120.70 | $ 35.47 | 42% |
| 100 | $ 223.47 | $ 255.90 | $ 32.43 | 15% | $ 89.44 | $ 121.87 | $ 32.43 | 36% |
| 150 | $ 278.00 | $ 307.38 | $ 29.38 | 11% | $ 93.66 | $ 123.04 | $ 29.38 | 31% |
| 200 | $ 332.52 | $ 358.85 | $ 26.33 | 8% | $ 97.87 | $ 124.20 | $ 26.33 | 27% |
| 250 | $ 387.04 | $ 410.33 | $ 23.29 | 6% | $ 102.08 | $ 125.37 | $ 23.29 | 23% |
| 300 | $ 441.56 | $ 461.81 | $ 20.25 | 5% | $ 106.29 | $ 126.54 | $ 20.25 | 19% |
| 400 | $ 550.61 | $ 564.76 | $ 14.15 | 3% | $ 114.72 | $ 128.87 | $ 14.15 | 12% |
| 500 | $ 659.66 | $ 667.71 | $ 8.05 | 1% | $ 123.15 | $ 131.20 | $ 8.05 | 7% |
| 600 | $ 768.70 | $ 770.67 | $ 1.97 | 0% | $ 131.57 | $ 133.54 | $ 1.97 | 1% |
| 700 | $ 877.75 | $ 873.62 | $ (4.13) | 0% | $ 140.00 | $ 135.87 | $ (4.13) | -3% |
| 730 | $ 910.46 | $ 904.51 | $ (5.95) | -1% | $ 142.53 | $ 136.57 | $ (5.96) | -4% |

# PECO
## Comparison of Monthly Bills
## Rate GS General Service Demand Measurement
## Demand = 9 kW

| | Total Bill | | | | Excluding Generation & Transmission | | | |
|---|---|---|---|---|---|---|---|---|
| Hrs Usage | Existing Rate | Proposed Rate | $ Change | % Change | Existing Rate | Proposed Rate | $ Change | % Change |
| 0 | $ 22.64 | $ 27.86 | $ 5.22 | 23% | $ 22.64 | $ 27.86 | $ 5.22 | 23% |
| 50 | $ 121.75 | $ 147.23 | $ 25.48 | 21% | $ 63.79 | $ 89.27 | $ 25.48 | 40% |
| 100 | $ 159.13 | $ 182.87 | $ 23.74 | 15% | $ 66.34 | $ 90.08 | $ 23.74 | 36% |
| 150 | $ 196.52 | $ 218.50 | $ 21.98 | 11% | $ 68.90 | $ 90.88 | $ 21.98 | 32% |
| 200 | $ 233.91 | $ 254.14 | $ 20.23 | 9% | $ 71.46 | $ 91.69 | $ 20.23 | 28% |
| 250 | $ 271.30 | $ 289.78 | $ 18.48 | 7% | $ 74.02 | $ 92.50 | $ 18.48 | 25% |
| 300 | $ 308.68 | $ 325.42 | $ 16.74 | 5% | $ 76.57 | $ 93.31 | $ 16.74 | 22% |
| 400 | $ 383.46 | $ 396.69 | $ 13.23 | 3% | $ 81.69 | $ 94.92 | $ 13.23 | 16% |
| 500 | $ 458.23 | $ 467.97 | $ 9.74 | 2% | $ 86.80 | $ 96.54 | $ 9.74 | 11% |
| 600 | $ 533.01 | $ 539.24 | $ 6.23 | 1% | $ 91.92 | $ 98.15 | $ 6.23 | 7% |
| 700 | $ 607.79 | $ 610.52 | $ 2.73 | 0% | $ 97.04 | $ 99.77 | $ 2.73 | 3% |
| 730 | $ 630.22 | $ 631.90 | $ 1.68 | 0% | $ 98.57 | $ 100.26 | $ 1.69 | 2% |

Q. IV-E-1

Provide a cost study, which allocates the total cost of service to each proposed tariff rate schedule. Tariff rates schedules may be combined for this purpose provided that they are of a similar supply or end use nature. A statement describing which rates were combined and the reasons therefore should be submitted.

The rates of return for each tariff rate schedule as defined above should be determined at both determined at both the present and proposed rate levels. Base rate revenues should be used for this purpose unless there are good and sufficient reasons to include revenues derived from other sources. Should the latter be the case, an explanation of other revenue sources included and reasons therefore should accompany the cost allocation study.

The methods selected for use in allocating costs to rate classes should include cost analyses based on:

a. Peak responsibility.
b. Average and excess, on a non-coincident demand basis.
c. Company preferred method if different from the above-referenced methods, with rationale behind the selection. This study should include a statement of the sources and age of the load data used in the determination of demand responsibilities, a description of any special studies used to prepare the cost study, and the most recent overall system line loss study. The cost data used in the allocation study may be based on the test year.

A. IV-E-1

The testimony and exhibits of Company witness Alan B. Cohn, PECO Statement No. 6, provide the Company's complete class cost of service study.

Q. IV-E-2 Provide comparisons in either graphical or tabular form showing cost, as defined in the cost of service study, and proposed base rate revenues and usage for all residential and demand/energy rate schedules. Demand shall be for representative loads for each demand/energy rate schedule.

A. IV-E-2 Refer to Attachment IV-E-2(a) for the requested information.

**PECO Energy Company**
**Residential Customer**
**Cost vs. Revenue**

| | | |
|---|---|---|
| Customer Cost ($) | $ | 27.83 |
| Demand ($/kW) | $ | 7.06 |
| NCP (kW/kWh) | | 0.004 |
| Energy ($/kWh) | $ | 0.00097 |
| | | |
| Customer Charge ($) | $ | 12.00 |
| Variable Charge ($/kWh) | $ | 0.06088 |

| kWh | Cost | Revenue |
|---|---|---|
| 100 | $ 30.97 | $ 18.09 |
| 200 | $ 34.12 | $ 24.18 |
| 300 | $ 37.26 | $ 30.26 |
| 400 | $ 40.41 | $ 36.35 |
| 500 | $ 43.55 | $ 42.44 |
| 600 | $ 46.70 | $ 48.53 |
| 650 | $ 48.27 | $ 51.57 |
| 700 | $ 49.84 | $ 54.62 |
| 800 | $ 52.99 | $ 60.70 |
| 900 | $ 56.13 | $ 66.79 |
| 1,000 | $ 59.27 | $ 72.88 |
| 1,250 | $ 67.14 | $ 88.10 |
| 1,500 | $ 75.00 | $ 103.32 |
| 1,750 | $ 82.86 | $ 118.54 |
| 2,000 | $ 90.72 | $ 133.76 |

**PECO Energy Company**
**Residential Heating Customer**
**Cost vs. Revenue**

| | | |
|---|---|---|
| Customer Cost ($) | $ 28.34 | |
| Demand ($/kW) | $ 7.10 | |
| NCP (kW/kWh) | 0.005 | |
| Energy ($/kWh) | $ 0.00097 | |
| Customer Charge ($) | $ 12.00 | |
| Variable Charge ($/kWh) | $ 0.04927 | average of summer and winter charges |

| kWh | Cost | Revenue |
|---|---|---|
| 750 | $ 55.32 | $ 48.95 |
| 1,000 | $ 64.31 | $ 61.27 |
| 1,250 | $ 73.31 | $ 73.59 |
| 1,350 | $ 76.90 | $ 78.51 |
| 1,500 | $ 82.30 | $ 85.91 |
| 1,750 | $ 91.29 | $ 98.22 |
| 2,000 | $ 100.28 | $ 110.54 |
| 2,250 | $ 109.28 | $ 122.86 |
| 2,500 | $ 118.27 | $ 135.18 |
| 2,750 | $ 127.26 | $ 147.49 |
| 3,000 | $ 136.26 | $ 159.81 |

**PECO Energy Company**
**Rate General Service Customer**
**Cost vs. Revenue**

| | | | | |
|---|---|---|---|---|
| Customer Cost ($) | $ 33.15 | Customer Charge ($) | $ 23.22 | weighted average customer charges |
| Demand ($/kW) | $ 6.87 | Variable Charge ($/kWh) | $ 7.74 | |
| NCP (x Billed Demand) | 1.00 | | | |
| Energy ($/kWh) | $ 0.00077 | | | |

| 5 kW | | | 15 kW | | | 100 kW | | |
|---|---|---|---|---|---|---|---|---|
| **Hours Use** | **Cost** | **Revenue** | **Hours Use** | **Cost** | **Revenue** | **Hours Use** | **Cost** | **Revenue** |
| 50 | $ 68 | $ 62 | 50 | $ 137 | $ 139 | 50 | $ 724 | $ 797 |
| 100 | $ 68 | $ 62 | 100 | $ 137 | $ 139 | 100 | $ 728 | $ 797 |
| 150 | $ 68 | $ 62 | 150 | $ 138 | $ 139 | 150 | $ 732 | $ 797 |
| 200 | $ 68 | $ 62 | 200 | $ 139 | $ 139 | 200 | $ 736 | $ 797 |
| 250 | $ 68 | $ 62 | 250 | $ 139 | $ 139 | 250 | $ 740 | $ 797 |
| 300 | $ 69 | $ 62 | 300 | $ 140 | $ 139 | 300 | $ 743 | $ 797 |
| 350 | $ 69 | $ 62 | 350 | $ 140 | $ 139 | 350 | $ 747 | $ 797 |
| 400 | $ 69 | $ 62 | 400 | $ 141 | $ 139 | 400 | $ 751 | $ 797 |
| 450 | $ 69 | $ 62 | 450 | $ 141 | $ 139 | 450 | $ 755 | $ 797 |
| 500 | $ 69 | $ 62 | 500 | $ 142 | $ 139 | 500 | $ 759 | $ 797 |
| 550 | $ 70 | $ 62 | 550 | $ 143 | $ 139 | 550 | $ 763 | $ 797 |
| 600 | $ 70 | $ 62 | 600 | $ 143 | $ 139 | 600 | $ 766 | $ 797 |
| 650 | $ 70 | $ 62 | 650 | $ 144 | $ 139 | 650 | $ 770 | $ 797 |
| 700 | $ 70 | $ 62 | 700 | $ 144 | $ 139 | 700 | $ 774 | $ 797 |

**PECO Energy Company**
**Rate Primary Distribution Customer**
**Cost vs. Revenue**

| | | | |
|---|---|---|---|
| Customer Cost ($) | $ 233.69 | Customer Charge ($) | $ 300.00 |
| Demand ($/kW) | $ 6.07 | Variable Charge ($/kWh) | $ 7.24 |
| NCP (x Billed Demand) | 1.16 | | |
| Energy ($/kWh) | $ 0.00068 | | |

**100 kW**

| Hours Use | Cost | Revenue |
|---|---|---|
| 50 | $ 943 | $ 1,024 |
| 100 | $ 946 | $ 1,024 |
| 150 | $ 950 | $ 1,024 |
| 200 | $ 953 | $ 1,024 |
| 250 | $ 957 | $ 1,024 |
| 300 | $ 960 | $ 1,024 |
| 350 | $ 963 | $ 1,024 |
| 400 | $ 967 | $ 1,024 |
| 450 | $ 970 | $ 1,024 |
| 500 | $ 974 | $ 1,024 |
| 550 | $ 977 | $ 1,024 |
| 600 | $ 980 | $ 1,024 |
| 650 | $ 984 | $ 1,024 |
| 700 | $ 987 | $ 1,024 |

**250 kW**

| Hours Use | Cost | Revenue |
|---|---|---|
| 50 | $ 2,007 | $ 2,110 |
| 100 | $ 2,016 | $ 2,110 |
| 150 | $ 2,024 | $ 2,110 |
| 200 | $ 2,033 | $ 2,110 |
| 250 | $ 2,041 | $ 2,110 |
| 300 | $ 2,050 | $ 2,110 |
| 350 | $ 2,058 | $ 2,110 |
| 400 | $ 2,067 | $ 2,110 |
| 450 | $ 2,075 | $ 2,110 |
| 500 | $ 2,084 | $ 2,110 |
| 550 | $ 2,092 | $ 2,110 |
| 600 | $ 2,101 | $ 2,110 |
| 650 | $ 2,109 | $ 2,110 |
| 700 | $ 2,118 | $ 2,110 |

**500 kW**

| Hours Use | Cost | Revenue |
|---|---|---|
| 50 | $ 3,780 | $ 3,920 |
| 100 | $ 3,797 | $ 3,920 |
| 150 | $ 3,814 | $ 3,920 |
| 200 | $ 3,831 | $ 3,920 |
| 250 | $ 3,848 | $ 3,920 |
| 300 | $ 3,865 | $ 3,920 |
| 350 | $ 3,882 | $ 3,920 |
| 400 | $ 3,899 | $ 3,920 |
| 450 | $ 3,916 | $ 3,920 |
| 500 | $ 3,933 | $ 3,920 |
| 550 | $ 3,950 | $ 3,920 |
| 600 | $ 3,967 | $ 3,920 |
| 650 | $ 3,984 | $ 3,920 |
| 700 | $ 4,001 | $ 3,920 |

**PECO Energy Company**
**Rate High Tension Customer**
**Cost vs. Revenue**

| | | | |
|---|---|---|---|
| Customer Cost ($) | $ 280.66 | Customer Charge ($) | $ 306.00 |
| Demand ($/kW) | $ 4.06 | Variable Charge ($/kWh) | $ 5.08 |
| NCP (x Billed Demand) | 0.97 | | |
| Energy ($/kWh) | $ 0.00069 | | |

**500 kW**

| Hours Use | Cost | Revenue |
|---|---|---|
| 50 | $ 2,263 | $ 2,846 |
| 100 | $ 2,280 | $ 2,846 |
| 150 | $ 2,297 | $ 2,846 |
| 200 | $ 2,314 | $ 2,846 |
| 250 | $ 2,331 | $ 2,846 |
| 300 | $ 2,349 | $ 2,846 |
| 350 | $ 2,366 | $ 2,846 |
| 400 | $ 2,383 | $ 2,846 |
| 450 | $ 2,400 | $ 2,846 |
| 500 | $ 2,417 | $ 2,846 |
| 550 | $ 2,434 | $ 2,846 |
| 600 | $ 2,452 | $ 2,846 |
| 650 | $ 2,469 | $ 2,846 |
| 700 | $ 2,486 | $ 2,846 |

**1000 kW**

| Hours Use | Cost | Revenue |
|---|---|---|
| 50 | $ 4,245 | $ 5,386 |
| 100 | $ 4,279 | $ 5,386 |
| 150 | $ 4,313 | $ 5,386 |
| 200 | $ 4,348 | $ 5,386 |
| 250 | $ 4,382 | $ 5,386 |
| 300 | $ 4,416 | $ 5,386 |
| 350 | $ 4,451 | $ 5,386 |
| 400 | $ 4,485 | $ 5,386 |
| 450 | $ 4,519 | $ 5,386 |
| 500 | $ 4,554 | $ 5,386 |
| 550 | $ 4,588 | $ 5,386 |
| 600 | $ 4,622 | $ 5,386 |
| 650 | $ 4,657 | $ 5,386 |
| 700 | $ 4,691 | $ 5,386 |

**2500 kW**

| Hours Use | Cost | Revenue |
|---|---|---|
| 50 | $ 10,191 | $ 13,006 |
| 100 | $ 10,276 | $ 13,006 |
| 150 | $ 10,362 | $ 13,006 |
| 200 | $ 10,448 | $ 13,006 |
| 250 | $ 10,534 | $ 13,006 |
| 300 | $ 10,620 | $ 13,006 |
| 350 | $ 10,706 | $ 13,006 |
| 400 | $ 10,792 | $ 13,006 |
| 450 | $ 10,878 | $ 13,006 |
| 500 | $ 10,963 | $ 13,006 |
| 550 | $ 11,049 | $ 13,006 |
| 600 | $ 11,135 | $ 13,006 |
| 650 | $ 11,221 | $ 13,006 |
| 700 | $ 11,307 | $ 13,006 |

Q. V-A-1 Provide supporting schedules which indicate the procedures and calculations employed to develop the original cost plant and applicable reserves to the test year end as submitted in the current proceeding.

A. V-A-1 Refer to V-A-3 for the procedures and calculations employed to develop the original cost plant and applicable reserves.

Q. V-A-2 Provide a comparison of calculated depreciation reserve versus book reserve at the end of the test year. Provide this comparison by functional group and by account if available.

A. V-A-2 Not applicable. In its final order at Docket No. R-842590, the Pennsylvania Public Utility Commission approved PECO's use of the book reserve remaining life method of depreciation and also approved PECO's adjusted book reserve as the measure of accrued depreciation for ratemaking. Accordingly, PECO's claim for the depreciated original cost of utility plant in service is based on its book reserve, and a calculated depreciation reserve is not employed.

Q. V-A-3 Provide supporting schedules which indicate the procedures and calculations employed to develop the original cost plant and applicable reserves to the test year end as submitted in the current proceeding.

A. V-A-3 Refer to Attachments V-A-3(a) and V-A-3(c) for the calculations and procedures, respectively, employed to develop the original cost of utility plant at December 31, 2015 and December 31, 2016. Also, refer to Attachments V-A-3(b) and V-A-3(c) for the calculations and procedures, respectively, employed to develop the reserves by account at December 31, 2015 and December 31, 2016.

**PECO Energy Company**
**Plant Costs by Account**

**Attachment V-A-3(a)**
**Calculation of Original Cost of Utility Plant**
**December 31, 2015 & December 31, 2016**

| | (A) | (B) | (C) | (A+B+C) = (I) | (J) | (K) | (I+J+K) |
|---|---|---|---|---|---|---|---|
| **Functional Group** | **Cost - 12/31/2014** | **Additions- 2015** | **Retirements- 2015** | **Cost - 12/31/2015** | **Additions- 2016** | **Retirements- 2016** | **Cost - 12/31/2016** |
| **Intangible Plant** | | | | | | | |
| 302 Franchises and Consents | 162,934 | 0 | 0 | 162,934 | 0 | 0 | 162,934 |
| 303 Miscellaneous Intangible Plant | 87,297,771 | 19,931,191 | (169,380) | 107,059,582 | 12,978,495 | (169,380) | 119,868,697 |
| **Sub-total Intangible** | **87,460,705** | **19,931,191** | **(169,380)** | **107,222,516** | **12,978,495** | **(169,380)** | **120,031,631** |
| | | | | | | | |
| **Distribution Plant** | | | | | | | |
| 360 Land and Land Rights | 41,353,057 | 0 | 0 | 41,353,057 | 0 | 0 | 41,353,057 |
| 361 Structures and Improvements | 89,428,519 | 6,244,806 | (499,710) | 95,173,615 | 7,598,194 | (499,710) | 102,272,099 |
| 362 Station Equipment | 909,367,994 | 34,416,835 | (2,571,366) | 941,213,463 | 41,707,657 | (2,571,366) | 980,349,755 |
| 364 Poles, Towers and Fixtures | 616,433,996 | 30,148,551 | (4,280,375) | 642,302,172 | 37,025,278 | (4,280,375) | 675,047,075 |
| 365 Overhead Conductors & Devices | 1,014,654,326 | 63,004,061 | (6,314,574) | 1,071,343,813 | 77,208,233 | (6,314,574) | 1,142,237,473 |
| 366 Underground Conduit | 351,196,404 | 11,901,426 | (385,289) | 362,712,541 | 14,563,484 | (385,289) | 376,890,737 |
| 367 Underground Conductors & | 1,007,426,927 | 54,713,085 | (6,159,207) | 1,055,980,805 | 67,042,770 | (6,159,207) | 1,116,864,368 |
| 368 Line Transformers | 534,980,788 | 32,676,107 | (6,454,542) | 561,202,353 | 39,411,017 | (6,454,542) | 594,158,828 |
| 369 Services | 388,521,185 | 7,051,058 | (356,026) | 395,216,217 | 8,582,944 | (356,026) | 403,443,135 |
| 370 Meters | 265,903,096 | 14,437,757 | 0 | 280,340,853 | 9,033,086 | 0 | 289,373,939 |
| 371 Installations on Customer | 13,777,204 | 1,130,269 | 0 | 14,907,473 | 1,361,134 | 0 | 16,268,606 |
| 373 Street Lighting and Signal Systems | 54,746,915 | 1,749,072 | (539,482) | 55,956,506 | 2,121,886 | (539,482) | 57,538,910 |
| 374 Asset Retirement Costs for | 2,704,419 | 0 | (66,698) | 2,637,721 | 0 | (66,698) | 2,571,023 |
| **Sub-total Distribution** | **5,290,494,830** | **257,473,028** | **(27,627,269)** | **5,520,340,589** | **305,655,685** | **(27,627,269)** | **5,798,369,005** |
| | | | | | | | |
| **General Plant** | | | | | | | |
| 389 Land and Land Rights | 1,063,459 | 0 | 0 | 1,063,459 | 0 | 0 | 1,063,459 |
| 390 Structures and Improvements | 44,729,937 | 846,186 | (201,456) | 45,374,667 | 466,631 | (201,456) | 45,639,842 |
| 391 Office Furniture and Equipment | 8,717,005 | 1,003,622 | (113,783) | 9,606,844 | 691,583 | (113,783) | 10,184,644 |
| 393 Stores Equipment | 56,645 | 10,588 | (56,645) | 10,588 | 7,296 | 0 | 17,883 |
| 394 Tools, Shop & Garage Equip | 23,227,278 | 2,122,580 | (398,635) | 24,951,223 | 1,462,024 | (398,635) | 26,014,612 |
| 395 Laboratory Equipment | 419,715 | 0 | (97,860) | 321,855 | 0 | (97,860) | 223,994 |
| 397 Communication Equipment | 125,829,650 | 1,102,375 | (404,360) | 126,527,666 | (6,225) | (404,360) | 126,117,081 |
| 398 Miscellaneous Equipment | 1,343,778 | 0 | (360,872) | 982,906 | 0 | (360,872) | 622,034 |
| 399.1 Asset Retirement Costs | 375,219 | 0 | 0 | 375,219 | 0 | 0 | 375,219 |
| **Sub-total General** | **205,762,686** | **5,085,351** | **(1,633,611)** | **209,214,426** | **2,621,309** | **(1,576,966)** | **210,258,769** |
| | | | | | | | |
| **Common Plant** | | | | | | | |
| 301 Organization | 677,136 | 0 | 0 | 677,136 | 0 | 0 | 677,136 |
| 303 Software | 181,926,069 | 35,547,953 | (1,602,157) | 215,871,865 | 36,236,221 | (1,602,157) | 250,505,929 |
| 389 Land and Land Rights | 6,814,775 | 0 | 0 | 6,814,775 | 0 | 0 | 6,814,775 |
| 390 Structures and Improvements | 257,394,768 | 14,089,123 | (2,195,018) | 269,288,873 | 13,826,653 | (2,195,018) | 280,920,508 |
| 391 Office Furniture and Equipment | 33,928,622 | 3,762,489 | (6,117,097) | 31,574,014 | 4,762,489 | (6,117,097) | 30,219,406 |
| 392 Automobiles | 90,582 | 0 | 0 | 90,582 | 0 | 0 | 90,582 |
| 392 Heavy Trucks | 65,074,288 | 7,499,544 | (2,242,310) | 70,331,521 | 5,579,709 | (2,242,310) | 73,668,920 |
| 392 Light Trucks | 27,121,989 | 3,049,340 | (991,444) | 29,179,885 | 3,174,274 | (991,444) | 31,362,715 |
| 392 Other transprttn (off road) | 4,805,691 | (25) | 0 | 4,805,666 | (25) | 0 | 4,805,641 |
| 392 Tractors | 353,657 | (5) | (23,290) | 330,362 | (5) | (23,290) | 307,067 |
| 392 Trailers | 3,103,622 | 49,970 | (25,098) | 3,128,494 | (30) | (25,098) | 3,103,367 |
| 393 Stores Equipment | 671,333 | 34,045 | (94,533) | 610,844 | 33,499 | (94,533) | 549,811 |
| 394 Construction Tools | 90,340 | 39,044 | (90,340) | 39,044 | 38,418 | 0 | 77,462 |
| 394 Garage Equipment | 2,354,826 | (51) | (1,180,846) | 1,173,929 | (51) | (1,173,877) | 0 |
| 396 Power Operated Equipment | 185,066 | 0 | 0 | 185,066 | 0 | 0 | 185,066 |
| 397 Communication Equipment | 31,194,723 | 1,514,207 | (668,075) | 32,040,855 | 1,489,944 | (668,075) | 32,862,724 |
| 398 Miscellaneous Equipment | 1,662,533 | 316,108 | 0 | 1,978,641 | 310,999 | 0 | 2,289,640 |
| 399 Other Tangible Property | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 399.1 Asset Retirement Costs | 137,509 | 0 | (5,392) | 132,117 | 0 | (5,392) | 126,725 |
| **Sub-total Common** | **617,587,529** | **65,901,741** | **(15,235,600)** | **668,253,670** | **65,452,096** | **(15,138,291)** | **718,567,476** |

NOTE: Amounts for Intangible Plant, Electric General Plant and Common Plant are shown unallocated
**See Attachment V-A-3(c) for explanations of columnar heading letter references.**

PECO Energy Company
Plant Reserve by Account
2015 Rate Case Filing - Electric

Attachment V-A-3(b)
Calculation of Plant Reserve by Account
December 31, 2015 & December 31, 2016

| | (D) | | (E) | (F) | (G) | (H) | (D+E+F+G+H) = (L) | | (M) | (N) | (O) | (P) | (L+M+N+O+P) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Functional Group** | **Reserve 12/31/14** | **Base Depr** | **Depreciation** | **Retirements** | **Net Salvage** | **Transfers** | **Reserve-12/31/15** | **Base Depr** | **Depreciation** | **Retirements** | **Net Salvage** | **Transfers** | **Reserve-12/31/16** |
| **Intangible Plant** | | | | | | | | | | | | | |
| 302 Franchises and Consents | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 303 Software-5 Year Life | 40,276,583 | 15,565,857 | 17,692,193 | (169,380) | 0 | 0 | 57,799,397 | 17,692,193 | 17,148,952 | (169,380) | 0 | 0 | 74,778,970 |
| **Sub-total Intangible** | **40,276,583** | **15,565,857** | **17,692,193** | **(169,380)** | **0** | **0** | **57,799,397** | **17,692,193** | **17,148,952** | **(169,380)** | **0** | **0** | **74,778,970** |
| | | | | | | | | | | | | | |
| **Distribution Plant** | | | | | | | | | | | | | |
| 361 Structures and Improvements | 33,759,123 | 1,654,191 | 1,719,958 | (499,710) | (380,618) | 0 | 34,598,753 | 1,719,958 | 1,832,764 | (499,710) | (380,618) | 0 | 35,551,188 |
| 362 Station Equipment | 390,677,586 | 18,544,298 | 19,337,879 | (2,571,366) | (1,238,006) | 0 | 406,206,094 | 19,337,879 | 18,547,423 | (2,571,366) | (1,238,006) | 0 | 420,944,145 |
| 364 Poles, Towers and Fixtures | 129,120,815 | 12,268,031 | 12,785,357 | (4,280,375) | (3,518,456) | 0 | 134,107,341 | 12,785,357 | 13,672,695 | (4,280,375) | (3,518,456) | 0 | 139,981,205 |
| 365 Overhead Cndctrs & Devices | 231,133,365 | 20,066,903 | 20,879,772 | (6,314,574) | (6,163,924) | 0 | 239,534,639 | 20,879,772 | 22,274,036 | (6,314,574) | (6,163,924) | 0 | 249,330,177 |
| 366 Undergrnd Conduit & Manhole | 145,923,557 | 5,061,887 | 5,273,689 | (385,289) | (990,937) | 0 | 149,821,021 | 5,273,689 | 5,636,980 | (385,289) | (990,937) | 0 | 154,081,775 |
| 367 Undergrnd Cndctrs & Devices | 171,050,605 | 20,790,422 | 21,660,604 | (6,159,207) | (5,169,732) | 0 | 181,382,270 | 21,660,604 | 22,661,670 | (6,159,207) | (5,169,732) | 0 | 192,715,000 |
| 368 Line Transformers | 175,517,658 | 11,734,211 | 12,234,587 | (6,454,542) | 203,048 | 0 | 181,500,751 | 12,234,587 | 12,354,135 | (6,454,542) | 203,048 | 0 | 187,603,392 |
| 369 Services | 133,217,631 | 8,321,583 | 8,685,257 | (356,026) | (448,733) | 0 | 141,098,129 | 8,685,257 | 8,522,104 | (356,026) | (448,733) | 0 | 148,815,475 |
| 370 Meters | 22,429,248 | 16,973,900 | 17,054,608 | 0 | (11,187) | 0 | 39,472,668 | 17,054,608 | 17,627,854 | 0 | (11,187) | 0 | 57,089,335 |
| 371 Installs on Customers Prem | 3,864,648 | 816,334 | 851,590 | 0 | 0 | 0 | 4,716,238 | 851,590 | 912,061 | 0 | 0 | 0 | 5,628,299 |
| 373 Street Lighting & Signal Systems | 32,670,843 | 1,669,570 | 1,746,955 | (539,482) | (46,276) | 0 | 33,832,040 | 1,746,955 | 1,442,768 | (539,482) | (46,276) | 0 | 34,689,050 |
| 374 Asset Retirement costs | 1,582,031 | 151,253 | 151,253 | (66,698) | 0 | 0 | 1,666,586 | 151,253 | 151,253 | (66,698) | 0 | 0 | 1,751,141 |
| **Sub-total Distribution** | **1,470,947,109** | **118,052,584** | **122,381,509** | **(27,627,269)** | **(17,764,821)** | **0** | **1,547,936,529** | **122,381,509** | **125,635,743** | **(27,627,269)** | **(17,764,821)** | **0** | **1,628,180,182** |
| | | | | | | | | | | | | | |
| **General Plant** | | | | | | | | | | | | | |
| 390 Structures and Improvements | 10,312,446 | 1,000,902 | 1,018,260 | (201,456) | (374,591) | 0 | 10,754,658 | 1,018,260 | 1,278,898 | (201,456) | (374,591) | 0 | 11,457,509 |
| 391 Office Furniture and Equipment | 4,144,409 | 1,397,147 | 1,416,326 | (113,783) | 0 | 0 | 5,446,952 | 1,416,326 | 1,449,490 | (113,783) | 0 | 0 | 6,782,659 |
| 393 Stores Equipment | (750) | 4,887 | 6,267 | (56,645) | 0 | 0 | (51,128) | 6,267 | 8,655 | 0 | 0 | 0 | (42,473) |
| 394 Tools, Shop & Garage Equip | 5,390,358 | 1,718,628 | 1,745,641 | (398,635) | (1,988) | 0 | 6,735,376 | 1,745,641 | 1,792,352 | (398,635) | (1,988) | 0 | 8,127,106 |
| 395 Laboratory Equipment | 216,017 | 20,113 | 20,704 | (97,860) | 0 | 0 | 138,861 | 20,704 | 21,726 | (97,860) | 0 | 0 | 62,727 |
| 397 Communication Equipment | 18,283,695 | 6,213,102 | 6,304,497 | (404,360) | (6,225) | 0 | 24,177,607 | 6,304,497 | 7,004,596 | (404,360) | (6,225) | 0 | 30,771,618 |
| 398 Miscellaneous Equipment | 864,201 | 117,489 | 120,463 | (360,872) | 0 | 0 | 623,792 | 120,463 | 125,605 | (360,872) | 0 | 0 | 388,525 |
| 399.1 Asset Retirement Costs | 252,361 | 39,694 | 39,694 | 0 | 0 | 0 | 292,055 | 39,694 | 39,694 | 0 | 0 | 0 | 331,749 |
| **Sub-total General** | **39,462,736** | **10,511,963** | **10,671,852** | **(1,633,611)** | **(382,804)** | **0** | **48,118,173** | **10,671,852** | **11,721,016** | **(1,576,966)** | **(382,804)** | **0** | **57,879,420** |
| | | | | | | | | | | | | | |
| **Common Plant** | | | | | | | | | | | | | |
| 303 Software | 149,448,313 | 10,776,889 | 14,120,970 | (1,602,157) | 0 | 0 | 161,967,126 | 14,120,970 | 20,624,272 | (1,602,157) | 0 | 0 | 180,989,241 |
| 390 Structures and Improvements | 66,645,680 | 5,002,652 | 5,202,110 | (2,195,018) | (2,291,476) | 0 | 67,361,296 | 5,202,110 | 5,670,199 | (2,195,018) | (2,291,476) | 0 | 68,545,001 |
| 391 Office Furniture and Equipment | 17,807,871 | 4,741,413 | 5,444,706 | (6,117,097) | (37,511) | 0 | 17,097,970 | 5,444,706 | 7,146,703 | (6,117,097) | (37,511) | 0 | 18,090,065 |
| 392 Automobiles | 89,992 | 348 | 348 | 0 | 0 | 0 | 90,340 | 348 | 4 | 0 | 0 | 0 | 90,344 |
| 392 Light Trucks | 14,191,947 | 4,536,497 | 2,562,233 | (991,444) | 104,856 | 0 | 15,867,593 | 2,562,233 | 2,313,859 | (991,444) | 104,856 | 0 | 17,294,864 |
| 392 Heavy Trucks | 26,243,152 | 2,164,059 | 5,096,421 | (2,242,310) | 228,915 | 0 | 29,326,178 | 5,096,421 | 5,276,505 | (2,242,310) | 228,915 | 0 | 32,589,289 |
| 392 Tractors | 338,773 | 6,458 | 6,458 | (23,290) | 1,662 | 0 | 323,603 | 6,458 | 3,943 | (23,290) | 1,662 | 0 | 305,918 |
| 392 Trailers | 1,700,839 | 160,558 | 165,189 | (25,098) | 3,208 | 0 | 1,844,139 | 165,189 | 166,101 | (25,098) | 3,208 | 0 | 1,988,351 |
| 392 Other transportation (off road) | 3,143,465 | 194,995 | 194,995 | 0 | 1,630 | 0 | 3,340,090 | 194,995 | 194,995 | 0 | 1,630 | 0 | 3,536,715 |
| 393 Stores Equipment | (54,161) | 82,515 | 86,752 | (94,533) | 0 | 0 | (61,942) | 86,752 | 96,693 | (94,533) | 0 | 0 | (59,782) |
| 394 Construction Tools | (63,817) | 18,159 | 22,064 | (90,340) | 0 | 0 | (132,093) | 22,064 | 31,229 | 0 | 0 | 0 | (100,865) |
| 394 Garage Equipment | 1,373,428 | 121,200 | 121,200 | (1,180,846) | 7,116 | 0 | 320,898 | 121,200 | 121,200 | (1,173,877) | 7,116 | 0 | (724,664) |
| 396 Power Operated Equipment | 172,181 | 3,133 | 3,133 | 0 | 0 | 0 | 175,314 | 3,133 | 3,133 | 0 | 0 | 0 | 178,447 |
| 397 Communication Equipment | 11,508,267 | 1,782,442 | 1,862,092 | (668,075) | 0 | 0 | 12,702,285 | 1,862,092 | 2,049,015 | (668,075) | 0 | 0 | 14,083,225 |
| 398 Miscellaneous Equipment | 517,168 | 112,481 | 116,112 | 0 | (2,720) | 0 | 630,561 | 116,112 | 124,634 | 0 | (2,720) | 0 | 752,475 |
| 399.1 Asset Retirement Costs | 4,978 | 3,733 | 3,733 | (5,392) | 0 | | 3,319 | 3,733 | 3,733 | (5,392) | 0 | | 1,660 |
| **Sub-total Common** | **293,068,076** | **29,707,533** | **35,008,517** | **(15,235,600)** | **(1,984,319)** | **0** | **310,856,674** | **35,008,517** | **43,826,218** | **(15,138,291)** | **(1,984,319)** | **0** | **337,560,282** |

NOTE: Amounts for Intangible Plant, Electric General Plant and Common Plant are shown unallocated
**See Attachment V-A-3(c) for explanations of columnar heading letter references.**

**(A)** Source = December 31, 2014 ledger balance reported in the 12/31/14 FERC Form 1.

**(B) / (J)** For purposes of estimating the 2015 and 2016 utility plant-in-service additions by utility account, the 2015 and 2016 budgeted capital expenditures are placed in-service in the period capital expenditure is forecasted to occur, except for a limited number of projects where the capital expenditures are forecasted to occur over several periods. For multiple year projects, the capital expenditures are placed in-service based on the estimated in-service dates. For example, if the total Electric Distribution capital budgets (with no multiple year projects planned) for 2015 and 2016 are $100M and $100M, respectively then the additions placed in service would be $100M and $100M for 2015 and 2016, respectively. However, assume $10M multiple year project has forecasted capital expenditures of $5M in 2015 and $5M in 2016 with an estimated in-service date in 2016. In this scenario, the 2015 additions will be $95M and the 2016 additions will be $105M. The product of this calculation is used as the estimate for the 2015 and 2016 additions to Electric Distribution plant included in Attachment V-A-3A. This calculation has been performed at a functional level of plant, including Electric Distribution, General and Common plant for purposes of this filing.

After calculating the total plant additions by functional group using the methodology described previously, PECO allocated the total additions to the account level, as follows; (1) three-year historical average ratios of plant additions by utility accounts to the total plant additions for the historical period were calculated; (2) those ratios, or percentages by account, were applied to the total estimated 2015 and 2016 forecasted placed in-service, to derive the additions at the account level. For purposes of this calculation, the three-year period covered 2012 through 2014.

**(C) / (K)** Retirements are estimated using a three-year historical average at the account level. Years 2012 through 2014 were used to calculate the average.

**(D)** Obtained from the Power Plant fixed asset sub-ledger which is maintained by utility account. The amounts were reconciled to both the general ledger and FERC annual report at December 31, 2014.

**(E)** Accrued depreciation is calculated by applying the 2014 account-level net book value (NBV) depreciation rates to the account-level NBV amounts at December 31, 2014 to determine "baseline" depreciation. Depreciation for the estimated 2015 plant additions (see Attachment V-A-3A) is calculated using a half-year convention multiplied by the 2009 average service life (ASL) rate at the account level. For example, an account with an ASL of twenty-years would have a 5% annual rate.

**(F) / (N)** See (C) above.

**(G) / (O)** Net Salvage (salvage less cost of removal) is calculated using a historic three-year average of net salvage by account. For purposes of this filing, the three-year period covers the years from 2012 through 2014.

**(H) / (P)** N/A

**(M)** Accrued depreciation is calculated by applying the 2015 account-level net book value (NBV) depreciation rates to the account-level NBV amounts at December 31, 2015 to determine "baseline" depreciation. Depreciation for the estimated 2016 plant additions (see Attachment V-A-3A) is calculated using a half-year convention multiplied by the 2014 average service life (ASL) rate at the account level. For example, an account with an ASL of twenty-years would have a 5% annual rate.

Q. V-A-4 Provide a schedule showing details of rate case adjustments.

A. V-A-4 Refer to Exhibits SY-1 and SY-2 for the fully projected future test year (FPFTY) and the future test year (FTY), respectively. Within each exhibit, Schedules D-3 and D-5 provide a a summary of the ratemaking adjustments made to develop the Company's claims for revenues and expenses as well as references to the additional pages and schedules that show the details of each adjustment. A summary of the development of the Company's rate base claims is provided in Schedule C-1 of Exhibits SY-1 and SY-2 for the FPFTY and FTY, respectively, with references to additional schedules that show further detail. A summary of the development of the Company's claims for state and federal income tax is provided in Schedule D-18 of Exhibits SY-1 and SY-2 for the FPFTY and FTY, respectively, with references to additional schedules that show further detail.

Q. V-B-1 Provide a comparison of calculated depreciation accruals versus book accruals by function and by account if available.

A. V-B-1 Not applicable. See the Company's response to V-A-2.

Q. V-B-2

Supply a schedule by account or by depreciable group showing the survivor curve or interim survivor curve and annual accrual rate estimated to be appropriate:

(a) For the purpose of this filing
(b) For the purpose of the most recent rate filing prior to the current proceeding
(c) Supply an explanation for any major change in annual accrual rate by account or by depreciable group.
(d) Supply a comprehensive statement of major changes made in depreciation methods, procedures and techniques and the effect of the changes upon accumulated and annual depreciation, if any.

A. V-B-2

(a) Refer to Exhibit SAB-4 – Part V1
(b) Refer to attachment V-B-2(a) for the 2008 Electric, Gas, and Common Plant Service Life Study – Appendix D
(c) Refer to Exhibit SAB-4 – Executive Summary
(d) There have been no major changes in depreciation methods, procedures, or techniques.

Q. V-C-1 Where the retirement rate actuarial method of mortality analysis is utilized, set forth representative examples including charts depicting the observed and estimated survivor curves and a tabular presentation of the observed and estimated life tables plotted on the chart. Other analysis results shall be subject to request.

A. V-C-1 Refer to Exhibit SAB-4 – Part VII

Q. V-D-1 Provide the surviving original cost plant at the appropriate test year date or dates by account or functional property group and include claimed depreciation reserves. Provide annual depreciation accruals where appropriate. These calculations should be provided for plant in service as well as other categories of plant, including but not limited to, contributions in aid of construction, customers' advances for construction, and anticipated retirements associated with construction work in progress claims, if applicable.

A. V-D-1 Refer to PECO Exhibit SY-1 for the original cost plant data and the related reserve and depreciation accrual data.

Reimbursable construction costs are accounted for net of contribution in aid of construction ("CIAC") in account 107000-construction work in progress ("CWIP"). Upon completion of the project, after applying all CIAC, the remaining costs, if any, are moved from CWIP to plant-in-service. PECO's CIAC is embedded in the capital expenditures budget and included in plant additions using the conversion of capital to plant-in-service as described in the response to V-A-3.

PECO is making no claims for construction work in progress, and therefore, retirements from CWIP are not relevant for this proceeding.

Q. V-D-2 Provide representative examples of detail calculations by vintage at account or at a more detailed level, as performed for these purposes. Other vintage detail calculations shall be subject to request.

A. V-D-2 Refer to PECO Exhibit SAB-4 for the detailed depreciation calculations in Part VIII.

Q. V-E-1 Provide a description of the depreciation methods utilized in calculating annual depreciation amounts and depreciation reserves, together with a discussion of the significant factors which were considered in arriving at estimates of service life and forecast retirements by facilities, accounts or sub-accounts, as applicable.

A. V-E-1 Refer to PECO Exhibit SAB-4, which is a copy of the 2013 Electric, Gas and Common Plant Service Life Study that was submitted to the Pennsylvania Public Utility Commission in March 2015. See the Basis of the Study section in part I of the study for the information requested.

Q. VI-Statements

Provide the following unadjusted detailed schedules by function and by FERC account for the claimed test year and for each of the 3 preceding comparable years:

A. Balance sheet, in the form available
B. Statement of income
C. Plant in service
D. Accumulated depreciation

A. VI-Statements

A. Refer to PECO Exhibits SY-1 and SY-2 for the fully projected future test year and future test years. Refer to SDR-ROR-2 for the 2013 and 2014 balance sheets. Refer to Attachment VI-Statement(a) for the 2012 balance sheet.

B. Refer to PECO Exhibits SY-1 and SY-2 for the fully projected future test year and future test year. Refer to SDR-GEN-1 for the 2013 and 2014 income statements. Refer to Attachment VI-Statement(a) for the 2012 income statement.

C. Refer to PECO Exhibits SY-1 and SY-2 for the fully projected future test year and future test year. Refer to Attachment VI-Statement(b) for the 2012, 2013, and 2014 plant in service schedules.

D. Refer to PECO Exhibits SY-1 and SY-2 for the fully projected future test year and future test year. Refer to Attachment VI-Statement(b) for the 2012, 2013, and 2014 accumulated depreciation schedules.

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PECO Energy Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/01/2013 | End of 2012/Q4 |

## COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

| Line No. | Title of Account (a) | Ref. Page No. (b) | Current Year End of Quarter/Year Balance (c) | Prior Year End Balance 12/31 (d) |
|---|---|---|---|---|
| 1 | UTILITY PLANT | | | |
| 2 | Utility Plant (101-106, 114) | 200-201 | 8,784,514,495 | 8,437,945,721 |
| 3 | Construction Work in Progress (107) | 200-201 | 76,581,786 | 83,071,531 |
| 4 | TOTAL Utility Plant (Enter Total of lines 2 and 3) | | 8,861,096,281 | 8,521,017,252 |
| 5 | (Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115) | 200-201 | 2,794,987,585 | 2,660,713,112 |
| 6 | Net Utility Plant (Enter Total of line 4 less 5) | | 6,066,108,696 | 5,860,304,140 |
| 7 | Nuclear Fuel in Process of Ref., Conv.,Enrich., and Fab. (120.1) | 202-203 | 0 | 0 |
| 8 | Nuclear Fuel Materials and Assemblies-Stock Account (120.2) | | 0 | 0 |
| 9 | Nuclear Fuel Assemblies in Reactor (120.3) | | 0 | 0 |
| 10 | Spent Nuclear Fuel (120.4) | | 0 | 0 |
| 11 | Nuclear Fuel Under Capital Leases (120.6) | | 0 | 0 |
| 12 | (Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5) | 202-203 | 0 | 0 |
| 13 | Net Nuclear Fuel (Enter Total of lines 7-11 less 12) | | 0 | 0 |
| 14 | Net Utility Plant (Enter Total of lines 6 and 13) | | 6,066,108,696 | 5,860,304,140 |
| 15 | Utility Plant Adjustments (116) | | 0 | 0 |
| 16 | Gas Stored Underground - Noncurrent (117) | | 0 | 0 |
| 17 | OTHER PROPERTY AND INVESTMENTS | | | |
| 18 | Nonutility Property (121) | | 14,253,494 | 15,378,804 |
| 19 | (Less) Accum. Prov. for Depr. and Amort. (122) | | 1,979,556 | 2,074,511 |
| 20 | Investments in Associated Companies (123) | | 0 | 0 |
| 21 | Investment in Subsidiary Companies (123.1) | 224-225 | 1,989,375 | 10,688,140 |
| 22 | (For Cost of Account 123.1, See Footnote Page 224, line 42) | | | |
| 23 | Noncurrent Portion of Allowances | 228-229 | 0 | 0 |
| 24 | Other Investments (124) | | 22,123,764 | 21,932,915 |
| 25 | Sinking Funds (125) | | 0 | 0 |
| 26 | Depreciation Fund (126) | | 0 | 0 |
| 27 | Amortization Fund - Federal (127) | | 0 | 0 |
| 28 | Other Special Funds (128) | | 0 | 0 |
| 29 | Special Funds (Non Major Only) (129) | | 0 | 0 |
| 30 | Long-Term Portion of Derivative Assets (175) | | 0 | 0 |
| 31 | Long-Term Portion of Derivative Assets – Hedges (176) | | 0 | 0 |
| 32 | TOTAL Other Property and Investments (Lines 18-21 and 23-31) | | 36,387,077 | 45,925,348 |
| 33 | CURRENT AND ACCRUED ASSETS | | | |
| 34 | Cash and Working Funds (Non-major Only) (130) | | 0 | 0 |
| 35 | Cash (131) | | 15,652,672 | 25,981,546 |
| 36 | Special Deposits (132-134) | | 408,478 | 2,391,221 |
| 37 | Working Fund (135) | | 223,112 | 279,970 |
| 38 | Temporary Cash Investments (136) | | 344,285,779 | 159,245,008 |
| 39 | Notes Receivable (141) | | 0 | 0 |
| 40 | Customer Accounts Receivable (142) | | 290,445,764 | 300,326,820 |
| 41 | Other Accounts Receivable (143) | | 166,366,265 | 363,518,659 |
| 42 | (Less) Accum. Prov. for Uncollectible Acct.-Credit (144) | | 98,661,242 | 91,277,537 |
| 43 | Notes Receivable from Associated Companies (145) | | 0 | 82,000,000 |
| 44 | Accounts Receivable from Assoc. Companies (146) | | 11,117,976 | 4,779,325 |
| 45 | Fuel Stock (151) | 227 | 1,441,465 | 1,477,335 |
| 46 | Fuel Stock Expenses Undistributed (152) | 227 | 0 | 0 |
| 47 | Residuals (Elec) and Extracted Products (153) | 227 | 0 | 0 |
| 48 | Plant Materials and Operating Supplies (154) | 227 | 19,334,171 | 18,490,782 |
| 49 | Merchandise (155) | 227 | 0 | 0 |
| 50 | Other Materials and Supplies (156) | 227 | 0 | 0 |
| 51 | Nuclear Materials Held for Sale (157) | 202-203/227 | 0 | 0 |
| 52 | Allowances (158.1 and 158.2) | 228-229 | 0 | 0 |

## COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)(Continued)

| Line No. | Title of Account (a) | Ref. Page No. (b) | Current Year End of Quarter/Year Balance (c) | Prior Year End Balance 12/31 (d) |
|---|---|---|---|---|
| 53 | (Less) Noncurrent Portion of Allowances | | 0 | 0 |
| 54 | Stores Expense Undistributed (163) | 227 | 0 | 0 |
| 55 | Gas Stored Underground - Current (164.1) | | 55,284,476 | 76,893,584 |
| 56 | Liquefied Natural Gas Stored and Held for Processing (164.2-164.3) | | 8,372,242 | 8,996,822 |
| 57 | Prepayments (165) | | 33,359,156 | 20,278,594 |
| 58 | Advances for Gas (166-167) | | 0 | 0 |
| 59 | Interest and Dividends Receivable (171) | | 10,828 | 22,587,640 |
| 60 | Rents Receivable (172) | | 0 | 0 |
| 61 | Accrued Utility Revenues (173) | | 164,498,012 | 163,351,453 |
| 62 | Miscellaneous Current and Accrued Assets (174) | | 17,899,114 | 18,802,108 |
| 63 | Derivative Instrument Assets (175) | | 0 | 0 |
| 64 | (Less) Long-Term Portion of Derivative Instrument Assets (175) | | 0 | 0 |
| 65 | Derivative Instrument Assets - Hedges (176) | | 0 | 0 |
| 66 | (Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176 | | 0 | 0 |
| 67 | Total Current and Accrued Assets (Lines 34 through 66) | | 1,030,038,268 | 1,178,123,330 |
| 68 | **DEFERRED DEBITS** | | | |
| 69 | Unamortized Debt Expenses (181) | | 9,753,927 | 8,673,284 |
| 70 | Extraordinary Property Losses (182.1) | 230a | 0 | 0 |
| 71 | Unrecovered Plant and Regulatory Study Costs (182.2) | 230b | 0 | 0 |
| 72 | Other Regulatory Assets (182.3) | 232 | 1,400,517,753 | 1,245,350,537 |
| 73 | Prelim. Survey and Investigation Charges (Electric) (183) | | 0 | 0 |
| 74 | Preliminary Natural Gas Survey and Investigation Charges 183.1) | | 0 | 0 |
| 75 | Other Preliminary Survey and Investigation Charges (183.2) | | 0 | 0 |
| 76 | Clearing Accounts (184) | | 0 | 0 |
| 77 | Temporary Facilities (185) | | 0 | 0 |
| 78 | Miscellaneous Deferred Debits (186) | 233 | 763,229,854 | 783,973,156 |
| 79 | Def. Losses from Disposition of Utility Plt. (187) | | 0 | 0 |
| 80 | Research, Devel. and Demonstration Expend. (188) | 352-353 | 0 | 0 |
| 81 | Unamortized Loss on Reaquired Debt (189) | | 11,687,740 | 14,509,369 |
| 82 | Accumulated Deferred Income Taxes (190) | 234 | 254,997,963 | 137,262,702 |
| 83 | Unrecovered Purchased Gas Costs (191) | | 0 | 0 |
| 84 | Total Deferred Debits (lines 69 through 83) | | 2,440,187,237 | 2,189,769,048 |
| 85 | TOTAL ASSETS (lines 14-16, 32, 67, and 84) | | 9,572,721,278 | 9,274,121,866 |

| Name of Respondent<br>PECO Energy Company | This Report is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(mo, da, yr)<br>04/01/2013 | Year/Period of Report<br>end of 2012/Q4 |
|---|---|---|---|

## COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

| Line No. | Title of Account<br>(a) | Ref. Page No.<br>(b) | Current Year End of Quarter/Year Balance<br>(c) | Prior Year End Balance 12/31<br>(d) |
|---|---|---|---|---|
| 1 | PROPRIETARY CAPITAL | | | |
| 2 | Common Stock Issued (201) | 250-251 | 1,423,004,251 | 1,423,004,251 |
| 3 | Preferred Stock Issued (204) | 250-251 | 87,472,000 | 87,472,000 |
| 4 | Capital Stock Subscribed (202, 205) | | 0 | 0 |
| 5 | Stock Liability for Conversion (203, 206) | | 0 | 0 |
| 6 | Premium on Capital Stock (207) | | 0 | 0 |
| 7 | Other Paid-In Capital (208-211) | 253 | 965,048,951 | 956,530,728 |
| 8 | Installments Received on Capital Stock (212) | 252 | 0 | 0 |
| 9 | (Less) Discount on Capital Stock (213) | 254 | 0 | 0 |
| 10 | (Less) Capital Stock Expense (214) | 254b | 86,742 | 86,742 |
| 11 | Retained Earnings (215, 215.1, 216) | 118-119 | 3,343,984,384 | 3,221,241,177 |
| 12 | Unappropriated Undistributed Subsidiary Earnings (216.1) | 118-119 | -2,752,366,766 | -2,663,183,623 |
| 13 | (Less) Reaquired Capital Stock (217) | 250-251 | 0 | 0 |
| 14 | Noncorporate Proprietorship (Non-major only) (218) | | 0 | 0 |
| 15 | Accumulated Other Comprehensive Income (219) | 122(a)(b) | 819,863 | 421,178 |
| 16 | Total Proprietary Capital (lines 2 through 15) | | 3,067,875,941 | 3,025,398,969 |
| 17 | LONG-TERM DEBT | | | |
| 18 | Bonds (221) | 256-257 | 1,950,000,000 | 1,975,000,000 |
| 19 | (Less) Reaquired Bonds (222) | 256-257 | 0 | 0 |
| 20 | Advances from Associated Companies (223) | 256-257 | 184,418,609 | 184,418,609 |
| 21 | Other Long-Term Debt (224) | 256-257 | 0 | 0 |
| 22 | Unamortized Premium on Long-Term Debt (225) | | 0 | 0 |
| 23 | (Less) Unamortized Discount on Long-Term Debt-Debit (226) | | 2,509,512 | 2,707,055 |
| 24 | Total Long-Term Debt (lines 18 through 23) | | 2,131,909,097 | 2,156,711,554 |
| 25 | OTHER NONCURRENT LIABILITIES | | | |
| 26 | Obligations Under Capital Leases - Noncurrent (227) | | 0 | 0 |
| 27 | Accumulated Provision for Property Insurance (228.1) | | 0 | 0 |
| 28 | Accumulated Provision for Injuries and Damages (228.2) | | 40,312,454 | 38,471,414 |
| 29 | Accumulated Provision for Pensions and Benefits (228.3) | | 308,374,288 | 316,697,580 |
| 30 | Accumulated Miscellaneous Operating Provisions (228.4) | | 41,133,699 | 50,305,951 |
| 31 | Accumulated Provision for Rate Refunds (229) | | 0 | 0 |
| 32 | Long-Term Portion of Derivative Instrument Liabilities | | 0 | 0 |
| 33 | Long-Term Portion of Derivative Instrument Liabilities - Hedges | | 0 | 0 |
| 34 | Asset Retirement Obligations (230) | | 29,357,391 | 28,171,539 |
| 35 | Total Other Noncurrent Liabilities (lines 26 through 34) | | 419,177,832 | 433,646,484 |
| 36 | CURRENT AND ACCRUED LIABILITIES | | | |
| 37 | Notes Payable (231) | | 210,000,000 | 225,000,000 |
| 38 | Accounts Payable (232) | | 243,212,244 | 261,615,810 |
| 39 | Notes Payable to Associated Companies (233) | | 0 | 0 |
| 40 | Accounts Payable to Associated Companies (234) | | 77,757,131 | 63,856,710 |
| 41 | Customer Deposits (235) | | 51,020,556 | 52,603,072 |
| 42 | Taxes Accrued (236) | 262-263 | 2,835,249 | 3,616,409 |
| 43 | Interest Accrued (237) | | 31,892,993 | 27,438,125 |
| 44 | Dividends Declared (238) | | 923,941 | 923,941 |
| 45 | Matured Long-Term Debt (239) | | 0 | 0 |

## COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)(continued)

| Line No. | Title of Account (a) | Ref. Page No. (b) | Current Year End of Quarter/Year Balance (c) | Prior Year End Balance 12/31 (d) |
|---|---|---|---|---|
| 46 | Matured Interest (240) | | 0 | 0 |
| 47 | Tax Collections Payable (241) | | 42,010 | 554,363 |
| 48 | Miscellaneous Current and Accrued Liabilities (242) | | 71,674,293 | 74,679,022 |
| 49 | Obligations Under Capital Leases-Current (243) | | 0 | 0 |
| 50 | Derivative Instrument Liabilities (244) | | 0 | 0 |
| 51 | (Less) Long-Term Portion of Derivative Instrument Liabilities | | 0 | 0 |
| 52 | Derivative Instrument Liabilities - Hedges (245) | | 0 | 0 |
| 53 | (Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges | | 0 | 0 |
| 54 | Total Current and Accrued Liabilities (lines 37 through 53) | | 689,358,417 | 710,287,452 |
| 55 | DEFERRED CREDITS | | | |
| 56 | Customer Advances for Construction (252) | | 439,427 | 2,457,577 |
| 57 | Accumulated Deferred Investment Tax Credits (255) | 266-267 | 3,406,260 | 5,052,603 |
| 58 | Deferred Gains from Disposition of Utility Plant (256) | | 0 | 0 |
| 59 | Other Deferred Credits (253) | 269 | 6,282,617 | 8,832,568 |
| 60 | Other Regulatory Liabilities (254) | 278 | 710,974,290 | 649,471,151 |
| 61 | Unamortized Gain on Reaquired Debt (257) | | 0 | 0 |
| 62 | Accum. Deferred Income Taxes-Accel. Amort.(281) | 272-277 | 0 | 0 |
| 63 | Accum. Deferred Income Taxes-Other Property (282) | | 2,437,538,735 | 2,171,027,327 |
| 64 | Accum. Deferred Income Taxes-Other (283) | | 105,758,662 | 111,236,181 |
| 65 | Total Deferred Credits (lines 56 through 64) | | 3,264,399,991 | 2,948,077,407 |
| 66 | TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65) | | 9,572,721,278 | 9,274,121,866 |

## STATEMENT OF INCOME

Quarterly

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

Annual or Quarterly if applicable

5. Do not report fourth quarter data in columns (e) and (f)
6. Report amounts for accounts 412 and 413, Revenues and Expenses from Utility Plant Leased to Others, in another utility columnin a similar manner to a utility department. Spread the amount(s) over lines 2 thru 26 as appropriate. Include these amounts in columns (c) and (d) totals.
7. Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.

| Line No. | Title of Account (a) | (Ref.) Page No. (b) | Total Current Year to Date Balance for Quarter/Year (c) | Total Prior Year to Date Balance for Quarter/Year (d) | Current 3 Months Ended Quarterly Only No 4th Quarter (e) | Prior 3 Months Ended Quarterly Only No 4th Quarter (f) |
|---|---|---|---|---|---|---|
| 1 | UTILITY OPERATING INCOME | | | | | |
| 2 | Operating Revenues (400) | 300-301 | 3,195,247,674 | 3,719,798,729 | | |
| 3 | Operating Expenses | | | | | |
| 4 | Operation Expenses (401) | 320-323 | 1,969,223,141 | 2,425,290,127 | | |
| 5 | Maintenance Expenses (402) | 320-323 | 222,057,447 | 225,659,669 | | |
| 6 | Depreciation Expense (403) | 336-337 | 178,587,139 | 167,768,482 | | |
| 7 | Depreciation Expense for Asset Retirement Costs (403.1) | 336-337 | | 9,208 | | |
| 8 | Amort. & Depl. of Utility Plant (404-405) | 336-337 | 28,452,237 | 24,598,133 | | |
| 9 | Amort. of Utility Plant Acq. Adj. (406) | 336-337 | | | | |
| 10 | Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407) | | | | | |
| 11 | Amort. of Conversion Expenses (407) | | | | | |
| 12 | Regulatory Debits (407.3) | | 5,982,000 | 5,982,000 | | |
| 13 | (Less) Regulatory Credits (407.4) | | | | | |
| 14 | Taxes Other Than Income Taxes (408.1) | 262-263 | 161,544,252 | 204,490,268 | | |
| 15 | Income Taxes - Federal (409.1) | 262-263 | 72,649,852 | -79,647,847 | | |
| 16 | - Other (409.1) | 262-263 | 27,691,098 | -16,751,805 | | |
| 17 | Provision for Deferred Income Taxes (410.1) | 234, 272-277 | 190,832,396 | 377,218,257 | | |
| 18 | (Less) Provision for Deferred Income Taxes-Cr. (411.1) | 234, 272-277 | 146,267,793 | 120,642,888 | | |
| 19 | Investment Tax Credit Adj. - Net (411.4) | 266 | -1,646,343 | -1,850,554 | | |
| 20 | (Less) Gains from Disp. of Utility Plant (411.6) | | | | | |
| 21 | Losses from Disp. of Utility Plant (411.7) | | | | | |
| 22 | (Less) Gains from Disposition of Allowances (411.8) | | | | | |
| 23 | Losses from Disposition of Allowances (411.9) | | | | | |
| 24 | Accretion Expense (411.10) | | 59,977 | 217,858 | | |
| 25 | TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24) | | 2,709,165,403 | 3,212,340,908 | | |
| 26 | Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27 | | 486,082,271 | 507,457,821 | | |

STATEMENT OF INCOME FOR THE YEAR (Continued)

9. Use page 122 for important notes regarding the statement of income for any account thereof.
10. Give concise explanations concerning unsettled rate proceedings where a contingency exists such that refunds of a material amount may need to be made to the utility's customers or which may result in material refund to the utility with respect to power or gas purchases. State for each year effected the gross revenues or costs to which the contingency relates and the tax effects together with an explanation of the major factors which affect the rights of the utility to retain such revenues or recover amounts paid with respect to power or gas purchases.
11 Give concise explanations concerning significant amounts of any refunds made or received during the year resulting from settlement of any rate proceeding affecting revenues received or costs incurred for power or gas purches, and a summary of the adjustments made to balance sheet, income, and expense accounts.
12. If any notes appearing in the report to stokholders are applicable to the Statement of Income, such notes may be included at page 122.
13. Enter on page 122 a concise explanation of only those changes in accounting methods made during the year which had an effect on net income, including the basis of allocations and apportionments from those used in the preceding year. Also, give the appropriate dollar effect of such changes.
14. Explain in a footnote if the previous year's/quarter's figures are different from that reported in prior reports.
15. If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles report the information in a footnote to this schedule.

| ELECTRIC UTILITY | | GAS UTILITY | | OTHER UTILITY | | |
|---|---|---|---|---|---|---|
| Current Year to Date (in dollars) (g) | Previous Year to Date (in dollars) (h) | Current Year to Date (in dollars) (i) | Previous Year to Date (in dollars) (j) | Current Year to Date (in dollars) (k) | Previous Year to Date (in dollars) (l) | Line No. |
| | | | | | | 1 |
| 2,649,869,987 | 3,106,752,854 | 545,377,687 | 613,045,875 | | | 2 |
| | | | | | | 3 |
| 1,618,987,247 | 2,018,605,949 | 350,235,894 | 406,684,178 | | | 4 |
| 201,254,811 | 204,162,246 | 20,802,636 | 21,497,423 | | | 5 |
| 143,514,378 | 134,280,138 | 35,072,761 | 33,488,344 | | | 6 |
| | | | 9,208 | | | 7 |
| 23,362,717 | 20,110,453 | 5,089,520 | 4,487,680 | | | 8 |
| | | | | | | 9 |
| | | | | | | 10 |
| | | | | | | 11 |
| | | 5,982,000 | 5,982,000 | | | 12 |
| | | | | | | 13 |
| 156,614,855 | 198,345,392 | 4,929,397 | 6,144,876 | | | 14 |
| 82,392,428 | -74,055,385 | -9,742,576 | -5,592,462 | | | 15 |
| 32,449,643 | -14,839,985 | -4,758,545 | -1,911,820 | | | 16 |
| 125,388,377 | 327,357,047 | 65,444,019 | 49,861,210 | | | 17 |
| 112,701,612 | 97,742,836 | 33,566,181 | 22,900,052 | | | 18 |
| -1,153,747 | -1,289,651 | -492,596 | -560,903 | | | 19 |
| | | | | | | 20 |
| | | | | | | 21 |
| | | | | | | 22 |
| | | | | | | 23 |
| 16,828 | 18,530 | 43,149 | 199,328 | | | 24 |
| 2,270,125,925 | 2,714,951,898 | 439,039,478 | 497,389,010 | | | 25 |
| 379,744,062 | 391,800,956 | 106,338,209 | 115,656,865 | | | 26 |

Attachment VI-Statements(a)



| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PECO Energy Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/01/2013 | End of 2012/Q4 |

## STATEMENT OF INCOME FOR THE YEAR (continued)

| Line No. | Title of Account (a) | (Ref.) Page No. (b) | TOTAL Current Year (c) | TOTAL Previous Year (d) | Current 3 Months Ended Quarterly Only No 4th Quarter (e) | Prior 3 Months Ended Quarterly Only No 4th Quarter (f) |
|---|---|---|---|---|---|---|
| 27 | Net Utility Operating Income (Carried forward from page 114) | | 486,082,271 | 507,457,821 | | |
| 28 | Other Income and Deductions | | | | | |
| 29 | Other Income | | | | | |
| 30 | Nonutilty Operating Income | | | | | |
| 31 | Revenues From Merchandising, Jobbing and Contract Work (415) | | | | | |
| 32 | (Less) Costs and Exp. of Merchandising, Job. & Contract Work (416) | | | | | |
| 33 | Revenues From Nonutility Operations (417) | | 3,115,162 | 2,449,909 | | |
| 34 | (Less) Expenses of Nonutility Operations (417.1) | | 3,354,681 | 2,687,197 | | |
| 35 | Nonoperating Rental Income (418) | | 740,460 | 757,239 | | |
| 36 | Equity in Earnings of Subsidiary Companies (418.1) | 119 | -89,183,143 | -73,019,246 | | |
| 37 | Interest and Dividend Income (419) | | 2,912,520 | 4,602,894 | | |
| 38 | Allowance for Other Funds Used During Construction (419.1) | | 3,966,437 | 8,919,159 | | |
| 39 | Miscellaneous Nonoperating Income (421) | | -136,166 | 645,348 | | |
| 40 | Gain on Disposition of Property (421.1) | | 1,376,627 | 107,855 | | |
| 41 | TOTAL Other Income (Enter Total of lines 31 thru 40) | | -80,562,784 | -58,224,039 | | |
| 42 | Other Income Deductions | | | | | |
| 43 | Loss on Disposition of Property (421.2) | | 436,717 | 73,194 | | |
| 44 | Miscellaneous Amortization (425) | | | | | |
| 45 | Donations (426.1) | | 5,334,336 | 7,651,164 | | |
| 46 | Life Insurance (426.2) | | -1,887,651 | -282,671 | | |
| 47 | Penalties (426.3) | | -476,856 | 145,468 | | |
| 48 | Exp. for Certain Civic, Political & Related Activities (426.4) | | 1,162,854 | 1,252,178 | | |
| 49 | Other Deductions (426.5) | | 1,979,237 | 2,380,380 | | |
| 50 | TOTAL Other Income Deductions (Total of lines 43 thru 49) | | 6,548,637 | 11,219,713 | | |
| 51 | Taxes Applic. to Other Income and Deductions | | | | | |
| 52 | Taxes Other Than Income Taxes (408.2) | 262-263 | 59,973 | 49,130 | | |
| 53 | Income Taxes-Federal (409.2) | 262-263 | -71,397,064 | -66,393,369 | | |
| 54 | Income Taxes-Other (409.2) | 262-263 | -22,659,945 | -21,071,164 | | |
| 55 | Provision for Deferred Inc. Taxes (410.2) | 234, 272-277 | 2,035,102 | 2,644,313 | | |
| 56 | (Less) Provision for Deferred Income Taxes-Cr. (411.2) | 234, 272-277 | 12,923,078 | 205,509 | | |
| 57 | Investment Tax Credit Adj.-Net (411.5) | | | | | |
| 58 | (Less) Investment Tax Credits (420) | | | | | |
| 59 | TOTAL Taxes on Other Income and Deductions (Total of lines 52-58) | | -104,885,012 | -84,976,599 | | |
| 60 | Net Other Income and Deductions (Total of lines 41, 50, 59) | | 17,773,591 | 15,532,847 | | |
| 61 | Interest Charges | | | | | |
| 62 | Interest on Long-Term Debt (427) | | 105,002,103 | 118,427,813 | | |
| 63 | Amort. of Debt Disc. and Expense (428) | | 2,171,140 | 2,368,128 | | |
| 64 | Amortization of Loss on Reaquired Debt (428.1) | | 2,821,630 | 3,139,396 | | |
| 65 | (Less) Amort. of Premium on Debt-Credit (429) | | | | | |
| 66 | (Less) Amortization of Gain on Reaquired Debt-Credit (429.1) | | | | | |
| 67 | Interest on Debt to Assoc. Companies (430) | | 11,914,108 | 11,912,530 | | |
| 68 | Other Interest Expense (431) | | 3,264,267 | 2,739,149 | | |
| 69 | (Less) Allowance for Borrowed Funds Used During Construction-Cr. (432) | | 1,573,218 | 3,989,465 | | |
| 70 | Net Interest Charges (Total of lines 62 thru 69) | | 123,600,030 | 134,597,551 | | |
| 71 | Income Before Extraordinary Items (Total of lines 27, 60 and 70) | | 380,255,832 | 388,393,117 | | |
| 72 | Extraordinary Items | | | | | |
| 73 | Extraordinary Income (434) | | | | | |
| 74 | (Less) Extraordinary Deductions (435) | | | | | |
| 75 | Net Extraordinary Items (Total of line 73 less line 74) | | | | | |
| 76 | Income Taxes-Federal and Other (409.3) | 262-263 | | | | |
| 77 | Extraordinary Items After Taxes (line 75 less line 76) | | | | | |
| 78 | Net Income (Total of line 71 and 77) | | 380,255,832 | 388,393,117 | | |

| Name of Respondent | This Report is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PECO Energy Company | (1) X An Original<br>(2) __ A Resubmission | 04/01/2013 | 2012/Q4 |

FOOTNOTE DATA

***Schedule Page: 114 Line No.: 46 Column: c***

Reflects increase in cash surrender value of life insurance policies.

***Schedule Page: 114 Line No.: 46 Column: d***

Reflects increase in cash surrender value of life insurance policies.

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PECO Energy Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/01/2013 | End of 2012/Q4 |

## ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106)

1. Report below the original cost of electric plant in service according to the prescribed accounts.
2. In addition to Account 101, Electric Plant in Service (Classified), this page and the next include Account 102, Electric Plant Purchased or Sold; Account 103, Experimental Electric Plant Unclassified; and Account 106, Completed Construction Not Classified-Electric.
3. Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.
4. For revisions to the amount of initial asset retirement costs capitalized, included by primary plant account, increases in column (c) additions and reductions in column (e) adjustments.
5. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
6. Classify Account 106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in column (c). Also to be included in column (c) are entries for reversals of tentative distributions of prior year reported in column (b). Likewise, if the respondent has a significant amount of plant retirements which have not been classified to primary accounts at the end of the year, include in column (d) a tentative distribution of such retirements, on an estimated basis, with appropriate contra entry to the account for accumulated depreciation provision. Include also in column (d)

| Line No. | Account<br>(a) | Balance Beginning of Year<br>(b) | Additions<br>(c) |
|---|---|---|---|
| 1 | 1. INTANGIBLE PLANT | | |
| 2 | (301) Organization | | |
| 3 | (302) Franchises and Consents | 162,934 | |
| 4 | (303) Miscellaneous Intangible Plant | 24,853,153 | 20,997,956 |
| 5 | TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4) | 25,016,087 | 20,997,956 |
| 6 | 2. PRODUCTION PLANT | | |
| 7 | A. Steam Production Plant | | |
| 8 | (310) Land and Land Rights | | |
| 9 | (311) Structures and Improvements | | |
| 10 | (312) Boiler Plant Equipment | | |
| 11 | (313) Engines and Engine-Driven Generators | | |
| 12 | (314) Turbogenerator Units | | |
| 13 | (315) Accessory Electric Equipment | | |
| 14 | (316) Misc. Power Plant Equipment | | |
| 15 | (317) Asset Retirement Costs for Steam Production | | |
| 16 | TOTAL Steam Production Plant (Enter Total of lines 8 thru 15) | | |
| 17 | B. Nuclear Production Plant | | |
| 18 | (320) Land and Land Rights | | |
| 19 | (321) Structures and Improvements | | |
| 20 | (322) Reactor Plant Equipment | | |
| 21 | (323) Turbogenerator Units | | |
| 22 | (324) Accessory Electric Equipment | | |
| 23 | (325) Misc. Power Plant Equipment | | |
| 24 | (326) Asset Retirement Costs for Nuclear Production | | |
| 25 | TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24) | | |
| 26 | C. Hydraulic Production Plant | | |
| 27 | (330) Land and Land Rights | | |
| 28 | (331) Structures and Improvements | | |
| 29 | (332) Reservoirs, Dams, and Waterways | | |
| 30 | (333) Water Wheels, Turbines, and Generators | | |
| 31 | (334) Accessory Electric Equipment | | |
| 32 | (335) Misc. Power PLant Equipment | | |
| 33 | (336) Roads, Railroads, and Bridges | | |
| 34 | (337) Asset Retirement Costs for Hydraulic Production | | |
| 35 | TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34) | | |
| 36 | D. Other Production Plant | | |
| 37 | (340) Land and Land Rights | | |
| 38 | (341) Structures and Improvements | | |
| 39 | (342) Fuel Holders, Products, and Accessories | | |
| 40 | (343) Prime Movers | | |
| 41 | (344) Generators | | |
| 42 | (345) Accessory Electric Equipment | | |
| 43 | (346) Misc. Power Plant Equipment | | |
| 44 | (347) Asset Retirement Costs for Other Production | | |
| 45 | TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44) | | |
| 46 | TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45) | | |

| Name of Respondent<br>PECO Energy Company | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>04/01/2013 | Year/Period of Report<br>End of 2012/Q4 |
|---|---|---|---|

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

distributions of these tentative classifications in columns (c) and (d), including the reversals of the prior years tentative account distributions of these amounts. Careful observance of the above instructions and the texts of Accounts 101 and 106 will avoid serious omissions of the reported amount of respondent's plant actually in service at end of year.

7. Show in column (f) reclassifications or transfers within utility plant accounts. Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102, include in column (e) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.

8. For Account 399, state the nature and use of plant included in this account and if substantial in amount submit a supplementary statement showing subaccount classification of such plant conforming to the requirement of these pages.

9. For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchase, and date of transaction. If proposed journal entries have been filed with the Commission as required by the Uniform System of Accounts, give also date

| Retirements<br>(d) | Adjustments<br>(e) | Transfers<br>(f) | Balance at End of Year<br>(g) | | Line No. |
|---|---|---|---|---|---|
| | | | | | 1 |
| | | | | | 2 |
| | | | 162,934 | | 3 |
| | | 749 | 45,851,858 | | 4 |
| | | 749 | 46,014,792 | | 5 |
| | | | | | 6 |
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ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

| Line No. | Account (a) | Balance Beginning of Year (b) | Additions (c) |
|---|---|---|---|
| 47 | 3. TRANSMISSION PLANT | | |
| 48 | (350) Land and Land Rights | 60,183,461 | 190 |
| 49 | (352) Structures and Improvements | 34,976,747 | 1,653,213 |
| 50 | (353) Station Equipment | 576,505,843 | 44,502,905 |
| 51 | (354) Towers and Fixtures | 245,849,337 | -2,369,307 |
| 52 | (355) Poles and Fixtures | 13,839,755 | 5,897,917 |
| 53 | (356) Overhead Conductors and Devices | 151,498,875 | 14,951,870 |
| 54 | (357) Underground Conduit | 13,309,297 | -670,321 |
| 55 | (358) Underground Conductors and Devices | 83,292,365 | 3,203,533 |
| 56 | (359) Roads and Trails | 3,529,649 | -679,403 |
| 57 | (359.1) Asset Retirement Costs for Transmission Plant | 1,130,490 | |
| 58 | TOTAL Transmission Plant (Enter Total of lines 48 thru 57) | 1,184,115,819 | 66,490,597 |
| 59 | 4. DISTRIBUTION PLANT | | |
| 60 | (360) Land and Land Rights | 39,850,630 | 144,239 |
| 61 | (361) Structures and Improvements | 76,326,003 | -744,128 |
| 62 | (362) Station Equipment | 838,583,721 | 21,470,864 |
| 63 | (363) Storage Battery Equipment | | |
| 64 | (364) Poles, Towers, and Fixtures | 555,235,202 | 26,673,195 |
| 65 | (365) Overhead Conductors and Devices | 880,665,449 | 41,857,518 |
| 66 | (366) Underground Conduit | 323,690,587 | 8,051,049 |
| 67 | (367) Underground Conductors and Devices | 893,154,065 | 39,383,335 |
| 68 | (368) Line Transformers | 481,831,410 | 25,803,346 |
| 69 | (369) Services | 373,095,848 | 4,968,526 |
| 70 | (370) Meters | 194,746,419 | 52,119,230 |
| 71 | (371) Installations on Customer Premises | 11,291,536 | 2,485,668 |
| 72 | (372) Leased Property on Customer Premises | | |
| 73 | (373) Street Lighting and Signal Systems | 52,351,376 | 1,017,908 |
| 74 | (374) Asset Retirement Costs for Distribution Plant | 2,603,544 | 552,107 |
| 75 | TOTAL Distribution Plant (Enter Total of lines 60 thru 74) | 4,723,425,790 | 223,782,857 |
| 76 | 5. REGIONAL TRANSMISSION AND MARKET OPERATION PLANT | | |
| 77 | (380) Land and Land Rights | | |
| 78 | (381) Structures and Improvements | | |
| 79 | (382) Computer Hardware | | |
| 80 | (383) Computer Software | | |
| 81 | (384) Communication Equipment | | |
| 82 | (385) Miscellaneous Regional Transmission and Market Operation Plant | | |
| 83 | (386) Asset Retirement Costs for Regional Transmission and Market Oper | | |
| 84 | TOTAL Transmission and Market Operation Plant (Total lines 77 thru 83) | | |
| 85 | 6. GENERAL PLANT | | |
| 86 | (389) Land and Land Rights | 1,063,459 | |
| 87 | (390) Structures and Improvements | 40,167,115 | 2,264,402 |
| 88 | (391) Office Furniture and Equipment | 4,810,320 | 2,023,909 |
| 89 | (392) Transportation Equipment | | |
| 90 | (393) Stores Equipment | 883,850 | |
| 91 | (394) Tools, Shop and Garage Equipment | 15,430,520 | 1,992,501 |
| 92 | (395) Laboratory Equipment | 713,296 | |
| 93 | (396) Power Operated Equipment | | |
| 94 | (397) Communication Equipment | 91,239,755 | 7,578,410 |
| 95 | (398) Miscellaneous Equipment | 2,426,394 | |
| 96 | SUBTOTAL (Enter Total of lines 86 thru 95) | 156,734,709 | 13,859,222 |
| 97 | (399) Other Tangible Property | | |
| 98 | (399.1) Asset Retirement Costs for General Plant | 129,363 | 220,158 |
| 99 | TOTAL General Plant (Enter Total of lines 96, 97 and 98) | 156,864,072 | 14,079,380 |
| 100 | TOTAL (Accounts 101 and 106) | 6,089,421,768 | 325,350,790 |
| 101 | (102) Electric Plant Purchased (See Instr. 8) | | |
| 102 | (Less) (102) Electric Plant Sold (See Instr. 8) | | |
| 103 | (103) Experimental Plant Unclassified | | |
| 104 | TOTAL Electric Plant in Service (Enter Total of lines 100 thru 103) | 6,089,421,768 | 325,350,790 |

Attachment VI-Statements(a) Page 12 of 15

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

| Retirements (d) | Adjustments (e) | Transfers (f) | Balance at End of Year (g) | | Line No. |
|---|---|---|---|---|---|
| | | | | | 47 |
| | | -5,851 | 60,177,800 | | 48 |
| 10,697 | | -30,071 | 36,589,192 | | 49 |
| 3,665,488 | | | 617,343,260 | | 50 |
| 76,469 | | | 243,403,561 | | 51 |
| | | | 19,737,672 | | 52 |
| 2,090,029 | | | 164,360,716 | | 53 |
| | | | 12,638,976 | | 54 |
| 5,210 | | | 86,490,688 | | 55 |
| | | | 2,850,246 | | 56 |
| 1,047 | | | 1,129,443 | | 57 |
| 5,848,940 | | -35,922 | 1,244,721,554 | | 58 |
| | | | | | 59 |
| | | 829,377 | 40,824,246 | | 60 |
| 102,710 | | 30,071 | 75,509,236 | | 61 |
| 1,510,011 | | | 858,544,574 | | 62 |
| | | | | | 63 |
| 4,962,802 | | | 576,945,595 | | 64 |
| 6,275,122 | | | 916,247,845 | | 65 |
| 795,228 | | | 330,946,408 | | 66 |
| 6,505,447 | | | 926,031,953 | | 67 |
| 5,927,491 | | | 501,707,265 | | 68 |
| 354,358 | | | 377,710,016 | | 69 |
| 7,335,237 | -18,340,329 | | 221,190,083 | | 70 |
| | | | 13,777,204 | | 71 |
| | | | | | 72 |
| 361,796 | | | 53,007,488 | | 73 |
| 58,479 | | | 3,097,172 | | 74 |
| 34,188,681 | -18,340,329 | 859,448 | 4,895,539,085 | | 75 |
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| | | | | | 85 |
| | | | 1,063,459 | | 86 |
| 487,023 | | | 41,944,494 | | 87 |
| 12,781 | | | 6,821,448 | | 88 |
| | | | | | 89 |
| | | | 883,850 | | 90 |
| 411,563 | | | 17,011,458 | | 91 |
| | | | 713,296 | | 92 |
| | | | | | 93 |
| 150,537 | | | 98,667,628 | | 94 |
| 616,521 | | | 1,809,873 | | 95 |
| 1,678,425 | | | 168,915,506 | | 96 |
| | | | | | 97 |
| | 25,698 | | 375,219 | | 98 |
| 1,678,425 | 25,698 | | 169,290,725 | | 99 |
| 41,716,046 | -18,314,631 | 824,275 | 6,355,566,156 | | 100 |
| | | | | | 101 |
| | | | | | 102 |
| | | | | | 103 |
| 41,716,046 | -18,314,631 | 824,275 | 6,355,566,156 | | 104 |

| Name of Respondent | This Report is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PECO Energy Company | (1) X An Original<br>(2) _ A Resubmission | 04/01/2013 | 2012/Q4 |

FOOTNOTE DATA

***Schedule Page: 204 Line No.: 100 Column: e***

| | |
|---|---|
| ARC adjustments related to ARO Update - Distribution & Transmission | 25,698 |
| AMI Meter Events | (18,340,329) |
| **Total** | **(18,314,631)** |

Attachment VI-Statements(a)


| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PECO Energy Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/01/2013 | End of 2012/Q4 |

## ACCUMULATED PROVISION FOR DEPRECIATION OF ELECTRIC UTILITY PLANT (Account 108)

1. Explain in a footnote any important adjustments during year.
2. Explain in a footnote any difference between the amount for book cost of plant retired, Line 11, column (c), and that reported for electric plant in service, pages 204-207, column 9d), excluding retirements of non-depreciable property.
3. The provisions of Account 108 in the Uniform System of accounts require that retirements of depreciable plant be recorded when such plant is removed from service. If the respondent has a significant amount of plant retired at year end which has not been recorded and/or classified to the various reserve functional classifications, make preliminary closing entries to tentatively functionalize the book cost of the plant retired. In addition, include all costs included in retirement work in progress at year end in the appropriate functional classifications.
4. Show separately interest credits under a sinking fund or similar method of depreciation accounting.

| Line No. | Item (a) | Total (c+d+e) (b) | Electric Plant in Service (c) | Electric Plant Held for Future Use (d) | Electric Plant Leased to Others (e) |
|---|---|---|---|---|---|
| | **Section A. Balances and Changes During Year** | | | | |
| 1 | Balance Beginning of Year | 1,841,735,840 | 1,841,735,840 | | |
| 2 | Depreciation Provisions for Year, Charged to | | | | |
| 3 | (403) Depreciation Expense | 132,498,270 | 132,498,270 | | |
| 4 | (403.1) Depreciation Expense for Asset Retirement Costs | | | | |
| 5 | (413) Exp. of Elec. Plt. Leas. to Others | | | | |
| 6 | Transportation Expenses-Clearing | | | | |
| 7 | Other Clearing Accounts | | | | |
| 8 | Other Accounts (Specify, details in footnote): | 15,506,856 | 15,506,856 | | |
| 9 | | | | | |
| 10 | TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9) | 148,005,126 | 148,005,126 | | |
| 11 | Net Charges for Plant Retired: | | | | |
| 12 | Book Cost of Plant Retired | 41,656,520 | 41,656,520 | | |
| 13 | Cost of Removal | 22,607,894 | 22,607,894 | | |
| 14 | Salvage (Credit) | 1,794,343 | 1,794,343 | | |
| 15 | TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14) | 62,470,071 | 62,470,071 | | |
| 16 | Other Debit or Cr. Items (Describe, details in footnote): | -1,050,809 | -1,050,809 | | |
| 17 | Asset Retirement Costs - Deprec. & oth | 243,770 | 243,770 | | |
| 18 | Book Cost or Asset Retirement Costs Retired | -59,526 | -59,526 | | |
| 19 | Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18) | 1,926,404,330 | 1,926,404,330 | | |
| | **Section B. Balances at End of Year According to Functional Classification** | | | | |
| 20 | Steam Production | | | | |
| 21 | Nuclear Production | | | | |
| 22 | Hydraulic Production-Conventional | | | | |
| 23 | Hydraulic Production-Pumped Storage | | | | |
| 24 | Other Production | | | | |
| 25 | Transmission | 436,751,772 | 436,751,772 | | |
| 26 | Distribution | 1,464,519,482 | 1,464,519,482 | | |
| 27 | Regional Transmission and Market Operation | | | | |
| 28 | General | 25,133,076 | 25,133,076 | | |
| 29 | TOTAL (Enter Total of lines 20 thru 28) | 1,926,404,330 | 1,926,404,330 | | |
| | | | | | |

| Name of Respondent | This Report is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PECO Energy Company | (1) X An Original<br>(2) _ A Resubmission | 04/01/2013 | 2012/Q4 |

FOOTNOTE DATA

**Schedule Page: 219 Line No.: 8 Column: c**

| | |
|---|---|
| Depreciation of assets under the Act 129 Program charged to a Regulatory Asset (182.3): | 13,203 |
| Depreciation of assets under the Smart Meter Program charged to a Regulatory Asset (182.3): | 15,493,654 |
| **Total** | **15,506,857** |

**Schedule Page: 219 Line No.: 12 Column: c**

| | |
|---|---|
| Retirements per page 219 (Line #12, Column C) for account 108 | 41,656,520 |
| Retirements related to asset retirement costs (FIN 47) | 59,526 |
| Retirements per page 207 (Line #104, Column D) for Electric Plant in Service | **41,716,046** |

**Schedule Page: 219 Line No.: 16 Column: c**

| | |
|---|---|
| Adjustment related to AMI Meter events | (747,877) |
| ARC Adjustment related to ARO Update - Distribution and Transmission | (6,576) |
| Asset Retirement Obligation (ARO) COR - Transfers from Regulatory Asset - Distribution and Transmission | (296,356) |
| **Total** | **(1,050,809)** |

**PECO Energy Company**
**Electric Plant in Service and Accumulated Reserve**
**2012, 2013, and 2014**

| | | Column Labels | | | | | |
|---|---|---|---|---|---|---|---|
| | | 2012 | | 2013 | | 2014 | |
| Function | FERC REPORTING NAMING CONVENTION | Sum of Plant In Service | Sum of Accum Reserve | Sum of Plant In Service | Sum of Accum Reserve | Sum of Plant In Service | Sum of Accum Reserve |
| Common | 301 Organization | 677,135.89 | - | 677,135.89 | - | 677,135.89 | - |
| | 303 Software | 151,823,909.45 | (121,883,684.30) | 168,152,852.05 | (139,095,860.50) | 181,926,069.47 | (149,448,313.76) |
| | 389 Land and Land Rights | 6,814,774.83 | - | 6,814,774.83 | - | 6,814,774.83 | - |
| | 390 Structures and Improvements | 248,471,980.09 | (68,292,192.00) | 260,341,917.22 | (69,867,879.02) | 257,394,767.53 | (66,645,680.04) |
| | 391 Office Furniture and Equipment | 36,598,927.14 | (18,723,362.31) | 32,903,381.44 | (17,017,654.37) | 33,928,621.90 | (17,807,870.87) |
| | 392 Automobiles | 90,582.44 | (85,816.50) | 90,582.44 | (88,904.83) | 90,582.44 | (89,991.91) |
| | 392 Heavy Trucks | 55,255,150.16 | (22,040,452.28) | 60,091,642.16 | (24,479,015.10) | 65,074,287.76 | (26,243,151.64) |
| | 392 Light Trucks | 20,959,127.70 | (11,985,652.22) | 24,049,876.23 | (13,101,240.89) | 27,121,988.86 | (14,191,946.89) |
| | 392 Other transprttn (off road) | 4,483,207.51 | (2,820,217.47) | 4,628,862.36 | (2,948,714.95) | 4,805,691.31 | (3,143,464.91) |
| | 392 Tractors | 423,525.53 | (379,350.40) | 353,656.53 | (328,696.09) | 353,656.53 | (338,773.35) |
| | 392 Trailers | 2,514,429.95 | (1,507,303.14) | 2,533,072.61 | (1,576,628.14) | 3,103,622.02 | (1,700,839.19) |
| | 393 Stores Equipment | 715,921.30 | 157,633.07 | 755,249.23 | 63,406.08 | 671,332.79 | 54,160.98 |
| | 394 Construction Tools | 49,684.39 | 92,893.32 | 35,339.77 | 78,895.64 | 90,339.77 | 63,816.37 |
| | 394 Garage Equipment | 5,347,973.90 | (4,020,202.25) | 4,797,836.43 | (3,713,523.70) | 2,354,826.17 | (1,373,428.28) |
| | 396 Power Operated Equipment | 185,066.30 | (163,408.06) | 185,066.30 | (168,225.93) | 185,066.30 | (172,181.18) |
| | 397 Communication Equipment | 31,826,335.17 | (9,709,758.45) | 31,826,683.41 | (11,631,442.37) | 31,194,723.10 | (11,508,267.39) |
| | 398 Miscellaneous Equipment | 1,345,726.53 | (345,044.09) | 1,608,907.11 | (432,700.35) | 1,662,532.64 | (517,168.40) |
| | 399.1 Asset Retirement Costs | | | 136,831.01 | 29,893.11 | 137,509.27 | (4,977.76) |
| **Common Total** | | **567,583,458.28** | **(261,705,917.08)** | **599,983,667.02** | **(284,278,291.41)** | **617,587,528.58** | **(293,068,078.22)** |
| Electric - Distribution | 303 Miscellaneous Intangible Plant | 43,342,626.44 | (13,546,283.77) | 64,825,783.23 | (25,528,968.34) | 82,388,647.71 | (38,177,412.22) |
| | 360 Land and Land Rights | 40,265,776.95 | - | 40,571,596.23 | - | 41,353,057.27 | - |
| | 361 Structures and Improvements | 75,509,236.65 | (32,777,235.30) | 83,803,891.89 | (32,234,558.75) | 89,428,521.36 | (33,759,122.86) |
| | 362 Station Equipment | 858,544,574.06 | (362,309,021.31) | 881,837,098.37 | (374,571,979.17) | 909,367,993.98 | (390,677,585.75) |
| | 364 Poles, Towers and Fixtures | 576,945,594.89 | (119,985,331.52) | 589,529,430.50 | (124,609,926.49) | 616,433,994.53 | (129,120,815.21) |
| | 365 Overhead Conductors & Devices | 916,247,844.15 | (219,220,925.10) | 947,444,317.88 | (226,310,005.38) | 1,014,654,323.70 | (231,133,364.80) |
| | 366 Underground Conduit | 330,946,407.94 | (138,838,244.53) | 335,071,756.13 | (142,874,167.75) | 351,196,404.24 | (145,923,557.40) |
| | 367 Underground Conductors & Devices | 926,031,953.30 | (154,336,734.71) | 968,081,581.76 | (163,079,831.84) | 1,007,426,928.24 | (171,050,605.17) |
| | 368 Line Transformers | 501,707,264.95 | (165,443,396.66) | 511,319,239.39 | (170,873,121.33) | 534,980,788.19 | (175,517,657.69) |
| | 369 Services | 377,710,015.97 | (118,259,431.97) | 382,815,261.74 | (125,784,063.56) | 388,521,184.24 | (133,217,631.39) |
| | 370 Meters | 221,190,082.93 | (133,874,062.66) | 328,806,113.43 | (142,129,281.07) | 265,903,096.77 | (22,429,247.74) |
| | 371 Installations on Customer Premises | 13,777,203.59 | (2,216,834.87) | 13,777,203.59 | (3,041,042.92) | 13,777,203.59 | (3,864,647.93) |
| | 373 Street Lighting and Signal Systems | 53,007,488.37 | (30,522,906.82) | 53,871,762.95 | (31,795,122.85) | 54,746,914.95 | (32,670,842.50) |
| | 374 Asset Retirement Costs for Distribution Plant | 3,097,172.06 | (1,504,995.26) | 3,020,254.88 | (1,644,716.00) | 2,704,418.89 | (1,582,030.91) |
| **Electric - Distribution Total** | | **4,938,323,242.25** | **(1,492,835,404.48)** | **5,204,775,291.97** | **(1,564,476,785.45)** | **5,372,883,477.66** | **(1,509,124,521.57)** |
| Electric - General Plant | 302 Franchises and Consents | 162,934.12 | - | 162,934.12 | - | 162,934.12 | - |
| | 303 Miscellaneous Intangible Plant | 2,509,231.27 | (1,093,988.16) | 2,695,111.66 | (1,634,951.13) | 4,909,123.14 | (2,099,171.19) |
| | 389 Land and Land Rights | 1,063,458.66 | - | 1,063,458.66 | - | 1,063,458.66 | - |
| | 390 Structures and Improvements | 41,944,493.60 | (8,899,349.86) | 42,161,846.10 | (9,362,864.77) | 44,729,935.75 | (10,312,445.56) |
| | 391 Office Furniture and Equipment | 6,821,448.19 | (2,278,563.93) | 6,378,946.00 | (3,175,219.85) | 8,717,005.38 | (4,144,408.73) |
| | 393 Stores Equipment | 883,850.42 | (757,923.31) | 56,645.61 | 5,670.82 | 56,645.61 | 749.89 |
| | 394 Tools, Shop & Garage Equipment | 17,011,458.31 | (3,044,160.69) | 19,707,958.68 | (4,472,315.80) | 23,227,277.59 | (5,390,357.67) |
| | 395 Laboratory Equipment | 713,296.47 | (449,953.17) | 419,715.36 | (195,737.46) | 419,715.36 | (216,017.17) |
| | 397 Communication Equipment | 98,667,626.55 | (8,660,186.97) | 104,522,404.80 | (13,832,169.27) | 125,829,647.95 | (18,283,694.59) |
| | 398 Miscellaneous Equipment | 1,809,873.35 | (1,048,716.36) | 1,343,778.72 | (744,306.60) | 1,343,778.72 | (864,201.19) |
| | 399.1 Asset Retirement Costs | 375,218.74 | (127,047.00) | 375,218.74 | (204,382.83) | 375,218.74 | (252,360.97) |
| **Electric - General Plant Total** | | **171,962,889.68** | **(26,359,889.45)** | **178,888,018.45** | **(33,616,276.89)** | **210,834,741.02** | **(41,561,907.18)** |
| **Grand Total** | | **5,677,869,590.21** | **(1,780,901,211.01)** | **5,983,646,977.44** | **(1,882,371,353.75)** | **6,201,305,747.26** | **(1,843,754,506.97)** |

**NOTE: Amounts for Common Plant and Electric - General Plant are shown unallocated.**