DOVER MOTORSPORTS INC
Form 10-K
March 15, 2011
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United States

Securities and Exchange Commission

Washington, D.C. 20549

Form 10-K

Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

For the fiscal year ended December 31, 2010

Commission file number 1-11929

Dover Motorsports, Inc.

(Exact name of registrant as specified in its charter)

Delaware	**51-0357525**
(State or other jurisdiction of incorporation)	**(I.R.S. Employer Identification No.)**

1131 North DuPont Highway, Dover, Delaware 19901

(Address of principal executive offices)

(302) 883-6500

(Registrant s telephone number, including area code)

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

Title of Class	Name of Exchange on Which Registered
Common Stock, $.10 Par Value	**New York Stock Exchange**

Securities registered pursuant to Section 12(g) of the Act: None.

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ¨ No x

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or 15(d) of the Act. Yes ¨ No x

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes x No ¨

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ¨ No ¨

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

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

Large accelerated filer ¨	Accelerated filer ¨	Non-accelerated filer ¨	Smaller reporting company x

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes ¨ No x

The aggregate market value of common stock held by non-affiliates of the registrant was $28,957,964 as of June 30, 2010 (the last day of our most recently completed second quarter).

As of March 10, 2011, the number of shares of each class of the registrant s common stock outstanding is as follows:

Common Stock -	18,340,977 shares
Class A Common Stock -	18,510,975 shares

Documents Incorporated by Reference

Portions of the registrant s Proxy Statement in connection with the Annual Meeting of Stockholders to be held April 27, 2011 are incorporated by reference into Part III, Items 10 through 14 of this report.

Part I

References in this document to we, us and our mean Dover Motorsports, Inc. and/or its wholly owned subsidiaries, as appropriate.

Item 1. Business

Dover Motorsports, Inc. is a public holding company that is a leading marketer and promoter of motorsports entertainment in the United States. Through our subsidiaries, we own and operate Dover International Speedway® in Dover, Delaware and Nashville Superspeedway® near Nashville, Tennessee. We closed Gateway International Raceway® near St. Louis, Missouri, after the 2010 race season and will not promote any future events there see further discussion below. These three facilities promoted 13 major events during 2010 under the auspices of two of the premier sanctioning bodies in motorsports the National Association for Stock Car Auto Racing (NASCAR) and the National Hot Rod Association (NHRA).

In 2010, we promoted the following major events:

- 2 NASCAR Sprint Cup Series events;
- 6 NASCAR Nationwide Series events;
- 4 NASCAR Camping World Truck Series events; and
- 1 NHRA event.

In 2011, we are scheduled to promote 9 major events, all of which will be sanctioned by NASCAR.

We derive a substantial portion of our revenues from admissions, event-related and broadcasting revenues attributable to our NASCAR-sanctioned events at Dover International Speedway which were held in May and September. Total revenues from these events were approximately 80% of total revenues for 2010 and approximately 70% for 2009 and 2008.

We generate revenues primarily from the following sources:

- ticket sales;
- rights fees obtained for television and radio broadcasts of our events and ancillary rights fees;
- sponsorship payments;
- luxury suite rentals;
- hospitality tent rentals and catering;
- concessions and souvenir sales and vendor commissions for the right to sell concessions and souvenirs at our facilities;
- expo space rentals; and
- track rentals and other event-related revenues.

We began our motorsports operations in 1969 in Dover, Delaware. Our predecessor, Dover Downs, Inc., was also engaged in harness horse racing operations and later ran our other gaming operations. As a result of several restructurings, our operations were segregated into two main operating subsidiaries Dover International Speedway, Inc., incorporated in 1994, encompassed our motorsports operations, and Dover Downs, Inc., incorporated in 1967, conducted our gaming operations.

Effective March 31, 2002, we spun-off our gaming business which was then owned by our subsidiary, Dover Downs Gaming & Entertainment, Inc. (Gaming). On a tax-free basis, we made a pro rata distribution of all of the capital stock of Gaming to our stockholders. Our continuing operations subsequent to the spin-off consist solely of our motorsports activities.

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We closed our Memphis Motorsports Park facility in October 2009 and executed an agreement to sell it in December 2010. The real estate sale closed on January 31, 2011. After closing costs and including the proceeds from the separate sale of all personal property at the facility, our net proceeds were approximately $2,000,000, all of which was used to pay down indebtedness of the Memphis facility. Since the carrying amount of the long-lived assets of the Memphis facility exceeded the sales price, we recognized a non-cash impairment charge of $809,000 in the fourth quarter of 2010.

In November 2010, we announced the closing of our Gateway facility. The Gateway facility is located on approximately 290 acres of land in Madison, Illinois and the racetrack is primarily on leased property. We had long-term leases for approximately 150 acres with four landlords. We also own approximately 140 acres near the Gateway facility. In February 2011, three of the four landlords agreed to terminate the land leases in exchange for 18.5 acres of owned real estate and our agreement to abandon all improvements and certain personal property (including the racetrack) on the leased land. As a result, we recorded an expense for facility exit costs of $324,000 at December 31, 2010 primarily to record a liability for the value of the real property we conveyed to the landlords in connection with terminating the leases. As part of the lease termination agreement with one of the landlords, we provided a six month purchase option on the remaining approximately 120 acres of owned land at $10,000 per acre, which approximates our carrying value.

Dover International Speedway

We have promoted NASCAR-sanctioned racing events for 42 consecutive years at Dover International Speedway and currently promote five major NASCAR-sanctioned events at the facility annually. Two races are in the NASCAR Sprint Cup Series professional stock car racing circuit, two races are in the NASCAR Nationwide Series racing circuit and one race is in the NASCAR Camping World Truck Series racing circuit. Both NASCAR Sprint Cup Series events at Dover are scheduled to be broadcast on network television in 2011.

Each of the NASCAR Nationwide Series events and the Camping World Truck Series event at Dover International Speedway are conducted on the days before a NASCAR Sprint Cup Series event. Dover International Speedway is one of only seven speedways in North America that presents two NASCAR Sprint Cup Series events and two NASCAR Nationwide Series events each year. Additionally, it is one of only seven tracks to host three major NASCAR events at one facility on the same weekend. The spring and fall event dates have historically allowed Dover International Speedway to hold the first and last NASCAR Sprint Cup Series events in the Maryland to Maine region each year. Our fall event has historically been the second of ten races in the Chase for the NASCAR Sprint Cup which determines the NASCAR Sprint Cup Series champion for the racing season. Starting in 2011, our fall event will be the third race to determine the championship.

Dover International Speedway, widely known as the Monster Mile®, is a high-banked, one-mile, concrete superspeedway with permanent seating capacity of approximately 132,000. Unlike some superspeedways, substantially all grandstand and skybox seats offer an unobstructed view of the entire track. The concrete racing surface makes Dover International Speedway the only concrete superspeedway (one mile or greater in length) that conducts NASCAR Sprint Cup Series events. The superspeedway facility also features the Monster Bridge®. The climate controlled bridge spans across the width of the superspeedway at a height of 29 feet and houses 50-luxury seats, a refreshment bar and other amenities. The Monster Bridge is the only one of its kind in the motorsports industry and has been patented.

Nashville Superspeedway

In April 2001, we opened Nashville Superspeedway (Nashville) a motorsports complex approximately 30 miles from downtown Nashville in Wilson County, Tennessee. The 1.33-mile concrete superspeedway has 25,000 permanent grandstand seats with an infrastructure in place to expand to 150,000 seats as demand requires. Additionally, construction included lights at the superspeedway to allow for nighttime racing and the foundation work for a dirt track, short track and drag strip. Nashville Superspeedway promoted two NASCAR Nationwide Series events and two NASCAR Camping World Truck Series event during the 2010 season. The facility also hosted other regional and national touring events, as well as track rentals.

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Gateway International Raceway

Gateway International Raceway (Gateway) promoted four major events in 2010 two NASCAR Nationwide Series events, a NASCAR Camping World Truck Series event and an NHRA national event. The facility also hosted a number of regional and national touring events, as well as weekly events on its drag strip and road course rentals.

The auto racing facility includes a 1.25-mile paved oval track with 54,000 permanent seats, a nationally renowned drag strip capable of seating approximately 30,000 people and a road course. The facility, which is equipped with lights for nighttime racing, is located just across the Mississippi River in Madison, Illinois, within view of the Gateway Arch in St. Louis.

We closed the Gateway facility in the fourth quarter of 2010 and terminated the majority of our leases for the real property underlying the racetrack in February 2011.

Memphis Motorsports Park

Memphis Motorsports Park (Memphis) promoted no events in 2010.

The auto racing facility includes a 0.75-mile paved tri-oval track with approximately 20,000 permanent seats and a drag strip capable of seating approximately 25,000 people. The facility is located approximately 10 miles northeast of downtown Memphis, Tennessee.

We closed the Memphis facility in the fourth quarter of 2009 and held an auction for the real and personal property comprising the facility on December 14, 2010. An agreement of sale was entered into on that date and the sale closed on January 31, 2011.

Agreements with NASCAR

Sanction agreements are entered into with NASCAR on an annual basis. Pursuant to the typical NASCAR sanction agreement, NASCAR grants its sanction to a promoter, such as Dover International Speedway, to organize, promote and hold a particular competition. The promoter sells tickets to the competition, sells or arranges for the sale of merchandise and concessions, and sells advertising, sponsorships and hospitality services. NASCAR conducts the competition, arranges for the drivers, and has sole control over the competition, including the right to require alterations to the promoter s facility and the right to approve or disapprove any advertising or sponsorship of the promoter. NASCAR also has exclusive rights to exploit live broadcast and certain broadcast and intellectual property rights related to the competition, and exclusive rights to sponsorship and promotional rights relative to the series to which a particular competition belongs. The promoter must pay the sanction fee and purse monies and receives a share of the live broadcast revenue contracted for by NASCAR. The promoter is responsible for the condition of the facility, for compliance with laws, for control of the public, for fire and medical equipment and personnel, for security, for insurance and for providing facilities and services required by NASCAR officials and the live broadcast personnel.

Dover International Speedway, Inc. has entered into two sanction agreements with NASCAR pursuant to which it will organize and promote two NASCAR Sprint Cup Series events in 2011. Our business is substantially dependent on these two agreements. The economic terms of the two sanction agreements between NASCAR and Dover International Speedway relative to its 2011 NASCAR Sprint Cup Series competitions are as follows: Total purse and sanction fee to be paid by Dover International Speedway is $6,097,000 for the May event and $5,450,000 for the October event. Estimated live broadcast revenue to be received by Dover International Speedway is $13,109,000 for the May event and $10,857,000 for the October event. Live broadcast revenue figures are based on the assumption that all events on the 2011 NASCAR Sprint Cup Series schedule take place and that all promoters will be entitled to their respective percentage allocations as set by NASCAR. Dover International Speedway is also entitled to share, along with other promoters, in income which NASCAR derives from exploiting certain broadcast and intellectual property rights. Revenue for such rights attributable to Dover International Speedway s 2010 NASCAR Sprint Cup Series competitions amounted to approximately $600,000 and we reasonably anticipate that this will approximate the amount for its 2011 NASCAR Sprint Cup Series competitions.

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The following is a listing of our NASCAR events for 2011:

Subsidiary	Event	Date
Dover International Speedway, Inc.	NASCAR Sprint Cup Series	May 15, 2011
	NASCAR Nationwide Series	May 14, 2011
	NASCAR Camping World Truck Series	May 13, 2011
	NASCAR Sprint Cup Series	October 2, 2011
	NASCAR Nationwide Series	October 1, 2011
	NASCAR K&N Pro Series East	September 30, 2011
Nashville Speedway, USA, Inc.	NASCAR Nationwide Series	April 23, 2011
	NASCAR Camping World Truck Series	April 22, 2011
	NASCAR Nationwide Series	July 23, 2011
	NASCAR Camping World Truck Series	July 22, 2011

Impairment Charges Recorded in 2010

Based upon the economic conditions that existed in the second quarter of 2010 and their impact on our current and projected operations and cash flows, and the potential impact on real estate valuations, combined with our decision to notify NASCAR that we would not seek 2011 sanctions for the two Nationwide Series and one Camping World Truck Series events at our Gateway facility, we concluded that it was necessary for us to review the carrying value of the long-lived assets at Gateway for impairment. In accordance with the provisions of ASC Topic 360, *Property, Plant and Equipment,* the recoverability of assets to be held and used was measured by a comparison of the carrying amount of the asset to the estimated undiscounted future cash flows expected to result from the use and eventual disposition of the asset. As a result of the recoverability test, we concluded that the carrying amount of our Gateway facility exceeded the undiscounted cash flows.

Since the carrying amount of the assets exceeded the fair value, an impairment charge was recognized by the amount by which the carrying amount of the assets exceeded the fair value. Fair value of the assets for the Gateway facility was determined based on the value of owned real estate at the facility. The long-lived assets deemed to be impaired consisted of track facilities.

Based on the results of this analysis, we recorded a non-cash impairment charge in the second quarter of 2010 to write-down the carrying value of long-lived assets at our Gateway facility to fair value, as follows:

	Carrying Value of Long-Lived Assets	Fair Value of Long-Lived Assets	Non-Cash Impairment Charges
Gateway facility	$ 9,464,000	$ 1,500,000	$ 7,964,000

We closed our Memphis Motorsports Park facility in October 2009 and executed an agreement to sell it in December 2010. The real estate sale closed on January 31, 2011. After closing costs and including the proceeds from the separate sale of all personal property at the facility, our net proceeds were approximately $2,000,000, all of which was used to pay down indebtedness of the Memphis facility. Since the carrying amount of the long-lived assets of the Memphis facility exceeded the sales price, we recognized a non-cash impairment charge of $809,000 in the fourth quarter of 2010.

Impairment Charge Recorded in 2009

We had an earlier agreement of sale relative to our Memphis Motorsports Park facility which expired in September 2009, and as a result, we concluded in the third quarter of 2009 that it was necessary for us to review the carrying value of the long-lived assets of our Memphis facility for impairment. The fair value of the assets for the Memphis facility was previously determined based upon the terms of the agreement of sale for purposes of our impairment assessment. The recoverability of assets to be held and used was measured by a comparison of the carrying amount of the asset to the sum of the estimated undiscounted cash flows expected to result from the use and eventual disposition of the asset. As a result of the recoverability test, we concluded that the carrying amount of our Memphis facility exceeded the undiscounted cash flows.

Since the carrying amount of the assets exceeded the fair value, an impairment charge was recognized by the amount by which the carrying amount of the assets exceeded the fair value. Fair value of the assets for the Memphis facility was determined using a valuation methodology which gave specific consideration to the value of the land and an office building, net of demolition costs. The long-lived assets deemed to be impaired consisted of track facilities.

Based on the results of this analysis, we recorded a non-cash impairment charge in the third quarter of 2009 to write-down the carrying value of long-lived assets at our Memphis facility to fair value, as follows:

	Carrying Value of Long-Lived Assets	Fair Value of Long-Lived Assets	Non-Cash Impairment Charge
Memphis facility	$ 10,278,000	$ 2,800,000	$ 7,478,000

Impairment Charges Recorded in 2008

Based upon economic conditions that existed in the fourth quarter of 2008 and their impact on our current and projected operations and cash flows, and the potential impact on real estate valuations, combined with the fact that there was no change in the allocation of broadcast revenues to the NASCAR Nationwide Series for 2009, we concluded in the fourth quarter of 2008 that it was necessary for us to review the carrying value of the long-lived assets of each of our Midwest facilities, consisting of Nashville, Memphis and Gateway, for impairment. The recoverability of assets to be held and used was measured by a comparison of the carrying amount of the asset to the estimated undiscounted future cash flows expected to be generated by the asset. As a result of the recoverability test, we concluded that the carrying amount of each of our Midwest facilities exceeded the undiscounted cash flows.

Since the carrying amount of the assets exceeded the fair value, an impairment charge was recognized by the amount by which the carrying amount of the assets exceeded the fair value. Fair value of the assets for the Nashville and Gateway facilities was determined using a valuation methodology that consisted of the cost approach, which gave specific consideration to the value of the land plus contributory value to the improvements, and the comparable sales approach. Based upon the cost approach utilized for the valuations, there is an assumption that these two facilities will continue to operate as racetracks and it is our intention to continue operating them unless it is determined that future prospects no longer justify such action. Fair value of the assets for Memphis was determined using a valuation methodology that considered the terms of our agreement of sale and the comparable sales approach. The long-lived assets deemed to be impaired consisted of track facilities. These facilities have generated negative cash flows for several years and we expect that these negative cash flows will continue as we monitor industry and Nationwide series changes made by NASCAR while continuing our efforts to reduce operating expenses and increase revenues.

Based on the results of this analysis, we recorded non-cash impairment charges of $12,795,000 in 2008 to write-down the carrying value of long-lived assets at our Midwest facilities to fair value.

Competition

Our racing events compete with other racing events sanctioned by various racing bodies and with other sports and recreational events scheduled on the same dates. Racing events sanctioned by different organizations are often held on the same dates at different tracks. The quality of the competition, type of racing event, caliber of the event, sight lines, ticket pricing, location and customer conveniences, among other things, differentiate the motorsports facilities.

Seasonality

We derive a substantial portion of our total revenues from admissions, television broadcast rights and other event-related revenue attributable to major motorsports events held from April through October. As a result, our business is highly seasonal.

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Employees

As of December 31, 2010, we had approximately 68 full-time employees and 6 part-time employees. We engage temporary personnel to assist during our motorsports racing season, many of whom are volunteers. We believe that we enjoy a good relationship with our employees.

Available Information

We file annual, quarterly and current reports, information statements and other information with the United States Securities and Exchange Commission (the SEC). The public may read and copy any materials we 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. The SEC also maintains an Internet site that contains reports, proxy and information statements, and other information regarding issuers that file electronically with the SEC. The address of that site is http://www.sec.gov.

Internet Address

We maintain a website where additional information concerning our business and various upcoming events can be found. The address of our Internet website is http://www.dovermotorsports.com. We provide a link on our website, under Investor Relations, to our filings with the SEC, including our annual report on Form 10-K, proxy statement, Section 16 reports, quarterly reports on Form 10-Q, current reports on Form 8-K and all amendments to those reports.

Item 1A. Risk Factors

In addition to historical information, this report includes forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934, as amended, relating to our financial condition, profitability, liquidity, resources, business outlook, proposed acquisitions, market forces, corporate strategies, consumer preferences, contractual commitments, legal matters, capital requirements and other matters. Documents incorporated by reference into this report may also contain forward-looking statements. The Private Securities Litigation Reform Act of 1995 provides a safe harbor for forward-looking statements. To comply with the terms of the safe harbor, we note that a variety of factors could cause our actual results and experience to differ substantially from the anticipated results or other expectations expressed in our forward-looking statements. When words and expressions such as: believes, expects, anticipates, estimates, plans, intends, objectives, aims, projects, forecasts, possible, seeks, may, could, should, might, likely or similar words or expressions are used, as well a our view, there can be no assurance or there is no way to anticipate with certainty, forward-looking statements may be involved.

In the section that follows below, in cautionary statements made elsewhere in this report, and in other filings we have made with the SEC, we list important factors that could cause our actual results to differ from our expectations. Our actual results could differ materially from those anticipated in these forward-looking statements as a result of the risk factors described below and other factors set forth in or incorporated by reference in this report.

These factors and cautionary statements apply to all future forward-looking statements we make. Many of these factors are beyond our ability to control or predict. Do not put undue reliance on forward-looking statements or project any future results based on such statements or on present or prior earnings levels.

Additional information concerning these, or other factors, which could cause the actual results to differ materially from those in our forward-looking statements is contained from time to time in our other SEC filings. Copies of those filings are available from us and/or the SEC.

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Our Relationships With and the Success of NASCAR Is Vital To Our Success In Motorsports

Our continued success in motorsports is dependent upon the success of NASCAR and our ability to secure favorable contracts with and maintain a good working relationship with them. NASCAR regularly issues and awards sanctioned events and their issuance depends, in large part, on maintaining good working relationships with NASCAR. Our NASCAR events are sanctioned on an annual basis with no contractual obligation to renew. By awarding a sanctioned event or a series of sanctioned events, NASCAR does not warrant, nor are they responsible for, the financial success of any sanctioned event. Our success is directly tied to our ability to negotiate favorable terms to our sanction agreements, including the amount of the sanction fee and purse, and our ability to continue to derive economic benefits from such agreements, such as our share of live broadcast revenues.

Our ability to obtain additional sanctioned events in the future and to negotiate favorable terms to our sanction agreements and the success of NASCAR in attracting drivers and teams, signing series sponsors and negotiating favorable television and/or radio broadcast rights is dependent on many factors which are largely outside of our control. As our success depends on the terms of our sanction agreements and the success of each event or series that we are promoting, a material change in the terms of a sanction agreement or a material adverse effect on NASCAR, such as the loss or defection of top drivers, the loss of significant series sponsors, or the failure to obtain favorable broadcast coverage or to properly advertise the event or series could result in a reduction in our revenues from live broadcast coverage, admissions, luxury suite rentals, sponsorships, hospitality, concessions and merchandise, which could have a material adverse effect on our business, financial condition and results of operations.

We Rely On Sponsorship Contracts To Generate Revenues

We receive a portion of our annual revenues from sponsorship agreements, including the sponsorship of our various events and venues, such as title, official product and promotional partner sponsorships, billboards, signage and skyboxes. We are continuously in negotiations with existing sponsors and actively seeking new sponsors as there is significant competition for sponsorships. Some of our events may not secure a title sponsor every year, may not secure a sufficient number of sponsorships on favorable terms, or may not secure sponsorships sufficiently enough in advance of an event for maximum impact. Loss of our existing title sponsors or other major sponsorship agreements or failure to secure sponsorship agreements in the future on favorable terms could have a material adverse effect on our business, financial condition and results of operations.

Our Motorsports Events Face Intense Competition For Attendance, Television Viewership And Sponsorship

We compete with other auto speedways for the patronage of motor racing spectators as well as for sponsorships. Moreover, racing events sanctioned by different organizations are often held on the same dates at different tracks. The quality of the competition, type of racing event, caliber of the event, sight lines, ticket pricing, location and customer conveniences, among other things, distinguish the motorsports facilities. In addition, all of our events compete with other sports and recreational events scheduled on the same dates. As a result, our revenues and operations are affected not only by our ability to compete in the motorsports promotion market, but also by the availability of alternative spectator sports events, forms of entertainment and changing consumer preferences.

General Market And Economic Conditions, Including Consumer And Corporate Spending, Could Negatively Affect Our Financial Results

Our financial results depend significantly upon a number of factors relating to discretionary consumer and corporate spending, including economic conditions affecting disposable consumer income and corporate budgets such as employment, business conditions, interest rates and taxation rates.

These factors can impact both attendance at our events and advertising and marketing dollars available from the motorsports industry s principal sponsors and potential sponsors. Economic and other lifestyle conditions such as illiquid consumer and business credit markets adversely affect consumer and corporate spending thereby impacting our growth, revenue and profitability. Unavailability of credit on favorable terms or increases in interest rates can adversely impact our operations, growth, development and capital spending plans. General economic conditions were significantly and negatively impacted by the September 11, 2001 terrorist attacks and the war in Iraq and could be similarly affected by any future attacks, by a terrorist attack at any mass gathering or fear of such attacks, or by other acts or prospects of war. Any future attacks or wars or related threats could also increase our expenses related to insurance, security or other related matters. A weakened economic and business climate, as well as consumer uncertainty and the loss of consumer confidence created by such a climate, could adversely affect our financial results.

The Sales Tax And Property Tax Revenues To Service The Revenue Bonds For Infrastructure Improvements At Nashville May Be Inadequate

In September 1999, the Sports Authority of the County of Wilson (Tennessee) issued $25,900,000 in revenue bonds to build local infrastructure improvements which benefit the operation of Nashville Superspeedway, of which $21,000,000 was outstanding on December 31, 2010. Debt service on the bonds is payable solely from sales taxes and incremental property taxes generated from the facility. As of December 31, 2010 and 2009, $1,200,000 and $915,000, respectively, was available in the sales and incremental property tax fund maintained by the Sports Authority to pay the remaining principal and interest due under the bonds. During 2010, we paid $1,038,000 into the sales and incremental property tax fund and $753,000 was deducted from the fund for principal and interest payments. These bonds are direct obligations of the Sports Authority and are therefore not recorded on our consolidated balance sheet. In the event the sales taxes and incremental property taxes are insufficient to cover the payment of principal and interest on the bonds, we would become responsible for the difference. We are exposed to fluctuations in interest rates for these bonds. A significant increase in interest rates could result in us being responsible for debt service payments not covered by the sales and incremental property taxes generated from the facility. In the event we were unable to make the payments, they would be made under a $21,352,000 irrevocable direct-pay letter of credit issued by our bank group. We would be responsible to reimburse the banks for any drawings made under the letter of credit. Such an event could have a material adverse effect on our business, financial condition and results of operations and compliance with debt covenants.

We Have a Significant Amount of Indebtedness

As of December 31, 2010, we had total outstanding long-term debt of $38,200,000 under our credit facility. This is in addition to the Nashville Bonds described above. This indebtedness and any future increases in our outstanding borrowings could:

- make it more difficult for us to satisfy our debt obligations;
- increase our vulnerability to general adverse economic and industry conditions or a downturn in our business;
- increase our costs or difficulties in refinancing or replacing our outstanding obligations;
- require us to dedicate a substantial portion of our cash flow from operations to payments on our indebtedness, thereby reducing the availability of our cash flow to fund working capital, capital expenditures, dividends and other general corporate purposes;
- limit our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate;
- subject us to the risks that interest rates and our interest expense will increase; and
- place us at a competitive disadvantage compared to competitors that have less debt.

In addition, our credit facility is secured by substantially all of our assets and contains financial ratios that we are required to meet and other restrictive covenants that, among other things, limit or restrict our ability to pay dividends, borrow additional funds, make acquisitions, create liens on our properties and make investments.

Our ability to meet these financial ratios and covenants can be affected by events beyond our control, and there can be no assurance that we will be able to meet them. If there were an event of default under our credit facility, the lenders could elect to declare all amounts outstanding to be immediately due and payable. If we were unable to repay these amounts, the lenders could proceed against the collateral granted to them to secure the indebtedness.

Our current credit agreement is scheduled to mature on January 1, 2012. We are currently evaluating possible options to address the expiration of the credit facility including refinancing with a new credit facility or other available financing options. We believe that we will be able to obtain sufficient financing to address the credit facility expiration.

The Seasonality Of Our Motorsports Events Increases The Variability Of Quarterly Earnings

Our business has been, and is expected to remain, seasonal given that it depends on our outdoor events for a substantial portion of revenues. We derive a substantial portion of our motorsports revenues from admissions, event-related and broadcasting revenue attributable to our NASCAR-sanctioned events at Dover, Delaware which were held in May and September. Total revenues from these events were approximately 80% of total revenues for 2010 and approximately 70% for 2009 and 2008. This has been offset to some degree by our other motorsports events, but quarterly earnings will vary. All of our operating earnings are derived from our Dover facility.

With the closing of our Gateway facility, the portion of our motorsports revenues attributable to our NASCAR-sanctioned events at Dover will increase in the future. We estimate that approximately 90% of our total revenues will be generated by our Dover facility starting in 2011.

Our Insurance May Not Be Adequate To Cover Catastrophic Incidents

We maintain insurance policies that provide coverage within limits that are sufficient, in the opinion of management, to protect us from material financial loss incurred in the ordinary course of business. We also purchase special event insurance for motorsports events to protect against race-related liability. However, there can be no assurance that this insurance will be adequate at all times and in all circumstances. If we are held liable for damages beyond the scope of our insurance coverage, including punitive damages, our business, financial condition and results of operations could be materially and adversely affected.

In addition, sanctioning bodies could impose more stringent rules and regulations for safety, security and operational activities. Such regulations have included, for example, the installation of new retaining walls at our facilities, which have increased our capital expenditures, and increased security procedures which have increased our operational expenses.

Bad Weather Can Have An Adverse Financial Impact On Our Motorsports Events

We sponsor and promote outdoor motorsports events. Weather conditions, or even the forecast of poor weather, can affect sales of tickets, concessions and merchandise at these events. Although we sell many tickets well in advance of the outdoor events and these tickets are issued on a non-refundable basis, poor weather may adversely affect additional ticket sales and concessions and merchandise sales, which could have an adverse effect on our business, financial condition and results of operations.

We do not currently maintain weather-related insurance for major events. Due to the importance of clear visibility and safe driving conditions to motorsports racing events, outdoor racing events may be significantly affected by weather patterns and seasonal weather changes. Any unanticipated weather changes could impact our ability to stage events. This could have a material adverse effect on our business, financial condition and results of operations.

Postponement And/Or Cancellation Of Major Motorsports Events Could Adversely Affect Us

If one of our events is postponed because of weather or other reasons such as, for example, the general postponement of all major sporting events in this country following the September 11, 2001 terrorism attacks, we could incur increased expenses associated with conducting the rescheduled event, as well as possible decreased revenues from tickets, concessions and merchandise at the rescheduled event. If an event is cancelled, we could incur the expenses associated with preparing to conduct the event as well as lose the revenues, including live broadcast revenues associated with the event.

If a cancelled event is part of a NASCAR series, we could experience a reduction in the amount of money received from television revenues for all of our NASCAR-sanctioned events in the series that experienced the cancellation. This would occur if, as a result of the cancellation, and without regard to whether the cancelled event

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was scheduled for one of our facilities, NASCAR experienced a reduction in broadcast revenues greater than the amount scheduled to be paid to the promoter of the cancelled event.

Due To Our Concentrated Stock Ownership, Stockholders May Have No Effective Voice In Our Management

We have elected to be treated as a controlled corporation as defined by New York Stock Exchange (NYSE) Rule 303A. We are a controlled corporation because a single person, Henry B. Tippie, the Chairman of our Board of Directors, controls in excess of fifty percent of our voting power. This means that he has the ability to determine the outcome of the election of directors at our annual meetings and to determine the outcome of many significant corporate transactions, many of which only require the approval of a majority of our voting power. Such a concentration of voting power could also have the effect of delaying or preventing a third party from acquiring us at a premium. In addition, as a controlled corporation, we are not required to comply with certain NYSE rules.

We may not be able to maintain our listing with the NYSE

Our Common Stock is traded on the NYSE under the symbol DVD. We are required to maintain market capitalization of more than $50,000,000 (measured over a 30 day trading period) or stockholders equity of more than $50,000,000 in order to remain in compliance with NYSE continued listing standards. As of December 31, 2010, our stockholders equity was approximately $54.3 million. As of December 31, 2010, our 30 trading-day average market capitalization was approximately $66.0 million. During 2010, it has ranged from approximately $63.0 million to $80.9 million. If we were to fail to maintain the required stockholders equity and market capitalization, our stock could be delisted from trading on the NYSE. While we would typically be given the opportunity to submit an 18 month plan to the NYSE to demonstrate our ability to regain compliance with continued listing standards, there is no assurance that we would be able to formulate such a plan or that it would be accepted by the NYSE. The delisting of our stock from trading on the NYSE would result in the need to find another market on which our stock can be listed or cause our stock to cease trading on an active market, which could result in a reduction in the liquidity for our stock and a reduction in demand for our stock.

Non-compliance with NYSE continued listing standards or delisting from the NYSE could negatively impact us, including, without limitation, our relationships with stockholders, businesses and lenders, our access to debt and equity financing, and our ability to attract and retain personnel by means of equity compensation. This, in turn, could materially and adversely affect our business, financial condition and results of operations. Securities traded in the over-the-counter market generally have significantly less liquidity than securities traded on a national securities exchange, through factors such as a reduction in the number of investors that will consider investing in the securities, the number of market makers in the securities, reduction in securities analyst and news media coverage and lower market prices than might otherwise be obtained.

Our Success Depends on the Availability and Performance of Key Personnel

Our continued success depends upon the availability and performance of our senior management team which possesses unique and extensive industry knowledge and experience. Our inability to retain and attract key employees in the future, could have a negative effect on our operations and business plans.

We are Subject to Changing Governmental Regulations and Legal Standards that Could Increase Our Expenses

Our motorsports facilities are on large expanses of property which we own or lease. Laws and regulations governing the use and development of real estate may delay or complicate any improvements we choose to make and/or increase the costs of any improvements or our costs of operating.

If it is determined that damage to persons or property or contamination of the environment has been caused or exacerbated by the operation or conduct of our business or by pollutants, substances, contaminants or wastes used, generated or disposed of by us, or if pollutants, substances, contaminants or wastes are found on property currently or previously owned or operated by us, we may be held liable for such damage and may be required to pay the cost of investigation and/or remediation of such contamination or any related damage.

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State and local laws relating to the protection of the environment also can include noise abatement laws that may be applicable to our racing events. In addition certain laws and regulations, including the Americans with Disabilities Act and the Occupational Safety and Health Act are constantly evolving. Changes in the provisions or application of federal, state or local environmental, land use or other laws, regulations or requirements to our facilities or operations, or the discovery of previously unknown conditions, could require us to make additional material expenditures to remediate or attain compliance.

Regulations governing the use and development of real estate may prevent us from acquiring or developing prime locations for motorsports entertainment facilities, substantially delay or complicate the process of improving existing facilities, and/or increase the costs of any of such activities.

We undertake no obligation to publicly update or revise any forward-looking statements as a result of future developments, events or conditions. New risk factors emerge from time to time and it is not possible for us to predict all such risk factors, nor can we assess the impact of all such risk factors on our business or the extent to which any factor, or combination of factors, may cause actual results to differ significantly from those forecast in any forward-looking statements. Given these risks and uncertainties, stockholders should not overly rely or attach undue weight to our forward-looking statements as an indication of our actual future results.

Item 1B. Unresolved Staff Comments

We have not received any written comments that were issued within 180 days before December 31, 2010, the end of the fiscal year covered by this report, from the SEC staff regarding our periodic or current reports under the Securities Exchange Act of 1934 that remain unresolved.

Item 2. Properties

Dover International Speedway

Dover International Speedway is located in Dover, Delaware, on approximately 770 acres of land we own. Prior to the spin-off of Gaming from our company in 2002, both companies shared certain real property in Dover, Delaware. At the time of the spin-off, some of this real property was transferred to Gaming to ensure that the real property holdings of each company was aligned with its past uses and future business needs. During its harness racing season, Gaming has historically used the 5/8-mile harness racing track that is located on our property and is on the inside of our one-mile motorsports superspeedway. In order to continue this historic use, we granted a perpetual easement to the harness track to Gaming at the time of the spin-off. This perpetual easement allows Gaming to have exclusive use of the harness track during the period beginning November 1 of each year and ending April 30 of the following year, together with set up and tear down rights for the two weeks before and after such period. The easement requires that Gaming maintain the harness track but does not require the payment of any rent.

Various easements and agreements relative to access, utilities and parking have also been entered into between us and Gaming relative to our respective Dover, Delaware facilities. We pay rent to Gaming for the lease of our principal executive office space. Gaming also allows us to use its indoor grandstands in connection with our two annual motorsports weekends. This occasional grandstand use is not material to us and Gaming does not assess rent for it; Gaming may also discontinue our use at its discretion.

Nashville Superspeedway

Nashville Superspeedway is located on approximately 1,400 acres of land we own in Wilson County and Rutherford County, Tennessee. The facility is approximately 35 miles from downtown Nashville.

Gateway International Raceway

Gateway International Raceway is located on approximately 290 acres of land in Madison, Illinois, five miles from the Gateway Arch in St. Louis. We own approximately 140 acres and have long-term leases with purchase options (expiring in 2011, 2025 and 2070) for approximately 150 additional acres.

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We closed the Gateway facility in the fourth quarter of 2010 and terminated the majority of our leases for the real property underlying the racetrack in February 2011.

Memphis Motorsports Park

Memphis Motorsports Park is located on approximately 350 acres of land we own approximately ten miles northeast of downtown Memphis, Tennessee. We closed the Memphis facility in the fourth quarter of 2009 and held an auction for the real and personal property comprising the facility on December 14, 2010. An agreement of sale was entered into on that date and the sale closed on January 31, 2011.

Intellectual Property

We have various registered and common law trademark rights, including, but not limited to, Dover, Dover Motorsports, Dover International Speedway, Nashville Speedway, Nashville Superspeedway, Gateway International Raceway, Memphis Motorsports Park, Gateway Guy, Monster Mile, Velocity, Monster Bridge, The Most Exciting Seat in Sports!, Concrete Monster, Miles the Monster, Take a Kid to the Ra
also have limited rights to use the names and logos of NASCAR, various sponsors, drivers and other businesses in connection with promoting our events and certain merchandising programs. Due to the value of our intellectual property rights for promotional purposes, it is our intention to vigorously protect these rights, through litigation, if necessary.

Item 3. Legal Proceedings

We are a party to ordinary routine litigation incidental to our business. Management does not believe that the resolution of any of these matters is likely to have a material adverse effect on our results of operations, financial condition or cash flows.

Item 4. Reserved

Executive Officers Of The Registrant

See Part III, Item 10 of this Annual Report on Form 10-K for information about our executive officers.

Part II

Item 5. Market For Registrant s Common Equity, Related Stockholder Matters And Issuer Purchases Of Equity Securities

Our common stock is listed on the New York Stock Exchange (NYSE) under the ticker symbol DVD. Our Class A common stock is not publicly traded but is freely convertible on a one-for-one basis into common stock at any time at the option of the holder thereof. As of March 10, 2011, there were 18,340,977 shares of common stock and 18,510,975 shares of Class A common stock outstanding. There were 1,019 holders of record for common stock and 14 holders of record for Class A common stock.

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The high and low sales prices for our common stock on the NYSE and the dividends declared per share for the years ended December 31, 2010 and 2009 are detailed in the following table:

Quarter Ended:	High	Low	Dividends Declared
December 31, 2010	$ 2.01	$ 1.60	None
September 30, 2010	$ 1.99	$ 1.45	None
June 30, 2010	$ 2.29	$ 1.21	None
March 31, 2010	$ 2.40	$ 1.92	None
December 31, 2009	$ 2.32	$ 1.31	None
September 30, 2009	$ 1.75	$ 1.10	None
June 30, 2009	$ 2.18	$ 1.40	$ 0.010
March 31, 2009	$ 2.65	$ 1.11	$ 0.010

Dividends are prohibited by our credit facility.

On July 28, 2004, our Board of Directors authorized the repurchase of up to 2,000,000 shares of our outstanding common stock. The purchases may be made in the open market or in privately negotiated transactions as conditions warrant. The repurchase authorization has no expiration date, does not obligate us to acquire any specific number of shares and may be suspended at any time. No purchases of our equity securities were made pursuant to this authorization during the fourth quarter of 2010 and we had remaining repurchase authority of 1,634,607 shares.

Item 6. Selected Financial Data

Not applicable.

Item 7. Management s Discussion And Analysis Of Financial Condition And Results Of Operation

The following discussion is based upon and should be read together with the consolidated financial statements and notes thereto included elsewhere in this document.

We classify our revenues as admissions, event-related, broadcasting and other. Admissions includes ticket sales for all our events. Event-related revenue includes amounts received from sponsorship fees; luxury suite rentals; hospitality tent rentals and catering; concessions and souvenir sales and vendor commissions for the right to sell concessions and souvenirs at our facilities; sales of programs; track rentals and other event-related revenues. Broadcasting revenue includes rights fees obtained for television and radio broadcasts of events held at our speedways and ancillary media rights fees.

Revenues pertaining to specific events are deferred until the event is held. Concession revenue from concession stand sales and sales of souvenirs are recorded at the time of sale. Revenues and related expenses from barter transactions in which we receive advertising or other goods or services in exchange for sponsorships of motorsports events are recorded at fair value. Barter transactions accounted for $848,000, $936,000 and $1,163,000 of total revenues for the years ended December 31, 2010, 2009 and 2008, respectively.

Expenses that are not directly related to a specific event are recorded as incurred. Expenses that specifically relate to an event are deferred until the event is held, at which time they are expensed. These expenses include prize and point fund monies and sanction fees paid to various sanctioning bodies, including NASCAR, labor, marketing, cost of goods sold for merchandise and souvenirs, and other expenses associated with the promotion of our racing events.

Results of Operations

Year Ended December 31, 2010 vs. Year Ended December 31, 2009

Admissions revenue was $19,251,000 in 2010 as compared to $24,741,000 in 2009. The $5,490,000 decrease was primarily related to lower admissions revenue at our NASCAR event weekends at Dover International Speedway and to a lesser extent lower admissions at the other major events we promoted during 2010. We promoted thirteen major events during 2010 and fourteen during 2009. We believe the decrease in attendance was attributable primarily to the general downturn in economic conditions, including those affecting disposable consumer income and corporate budgets such as employment, business conditions, interest rates and taxation rates. We believe that adverse economic trends, particularly credit availability, the decline in consumer confidence and the rise in unemployment have increasingly contributed to the decrease in attendance. Additionally, revenue associated with our special and weekly events at our Memphis facility did not recur in 2010 since that facility closed during the fourth quarter of 2009.

Event-related revenue was $15,010,000 in 2010 as compared to $17,971,000 in 2009. The $2,961,000 decrease was primarily related to lower hospitality and luxury suite rentals, as well as lower concessions and souvenir sales as a result of the lower attendance and the aforementioned economic conditions. Additionally, revenue associated with our special and weekly events at our Memphis facility did not recur.

Broadcasting revenue increased to $28,681,000 in 2010 from $27,999,000 in 2009. The increase resulted entirely from higher broadcasting revenue for our NASCAR-sanctioned events promoted during 2010.

Operating and marketing expenses were $43,641,000 in 2010 as compared to $50,466,000 in 2009. The decrease was primarily related to cost savings from the closing of our Memphis facility during the fourth quarter of 2009, cost cutting measures that reduced operating expenses at most major events promoted during 2010 and lower costs associated with the decline in event-related revenue.

General and administrative expenses were $13,254,000 in 2010 and $12,174,000 in 2009. The increase was primarily related to higher real estate taxes at our Gateway facility. Additionally, the expensing of costs relating to a proposed merger with Dover Downs Gaming & Entertainment, Inc. (a company related through common ownership) contributed to the increase. The merger agreement was terminated in October 2010. These increases were partially offset by the closing of our Memphis facility during the fourth quarter of 2009.

We concluded in the second quarter of 2010 that it was necessary for us to review the carrying value of the long-lived assets of our Gateway facility for impairment. Based on the results of this analysis, we recorded a $7,964,000 non-cash impairment charge in the second quarter of 2010 to write-down the carrying value of long-lived assets at our Gateway facility to fair value.

We closed our Memphis Motorsports Park facility in October 2009 and executed an agreement to sell it in December 2010. The real estate sale closed on January 31, 2011. After closing costs and including the proceeds from the separate sale of all personal property at the facility, our net proceeds were approximately $2,000,000, all of which was used to pay down indebtedness of the Memphis facility. Since the carrying amount of the long-lived assets of the Memphis facility exceeded the sales price, we recognized a non-cash impairment charge of $809,000 in the fourth quarter of 2010.

In November 2010, we announced the closing of our Gateway facility. The Gateway facility is located on approximately 290 acres of land in Madison, Illinois and the racetrack is primarily on leased property. We had long-term leases for approximately 150 acres with four landlords. We also own approximately 140 acres near the Gateway facility. In February 2011, three of the four landlords agreed to terminate the land leases in exchange for 18.5 acres of owned real estate and our agreement to abandon all improvements and certain personal property (including the racetrack) on the leased land. As a result, we recorded an expense for facility exit costs of $324,000 at December 31, 2010 primarily to record a liability for the value of the real property we conveyed to the landlords in connection with terminating the leases. As part of the lease termination agreement with one of the landlords, we provided a six month purchase option on the remaining approximately 120 acres of owned land at $10,000 per acre, which approximates our carrying value.

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Depreciation and amortization expense decreased to $6,190,000 in 2010 as compared to $6,467,000 in 2009.

During 2010, we recognized a gain of $398,000 as a result of insurance proceeds received for damage to grandstands at our Memphis facility.

Net interest expense was $2,460,000 in 2010 as compared to $2,110,000 in 2009. We reversed $878,000 and $1,011,000 in 2010 and 2009, respectively, of previously recorded interest expense on uncertain income tax positions which are no longer subject to examination. Excluding the interest expense we recorded related to uncertain income tax positions, our net interest expense was $3,213,000 in 2010 as compared to $2,795,000 in 2009. The increase was due primarily to a higher average interest rate on our credit facility and the amortization of higher credit facility amendment fees.

On July 21, 2010, we redeemed the $1,751,000 of remaining outstanding bonds with Southwestern Illinois Development Authority (SWIDA) for $1,909,000 (including a $158,000 premium to the bondholders). The redemption resulted in a loss on extinguishment of debt of $208,000 (including the premium, professional fees and the write-off of deferred financing costs) during 2010.

Loss before income tax benefit was $11,486,000 in 2010 as compared to $7,909,000 in 2009. Excluding the non-cash impairment charges and facility exit costs, our adjusted loss before income tax benefit was $2,389,000 in 2010 as compared to $431,000 in 2009.

	2010	2009
Loss before income tax benefit	$ (11,486,000)	$ (7,909,000)
Non-cash impairment charges	8,773,000	7,478,000
Facility exit costs	324,000	
Adjusted loss before income taxes	$ (2,389,000)	$ (431,000)

The above financial information is presented using other than generally accepted accounting principles (non-GAAP) and is reconciled to comparable information presented using GAAP. Non-GAAP adjusted loss before income taxes is derived by adjusting amounts determined in accordance with GAAP for the aforementioned non-cash impairment charge and facility exit costs. We believe such non-GAAP information is useful and meaningful to investors, and is used by investors and us to assess core operations. This non-GAAP financial information may not be comparable to similarly titled measures used by other entities and should not be considered as an alternative to loss before income tax benefit which is determined in accordance with GAAP.

Our effective income tax rates for 2010 and 2009 were 28.8% and 25.5%, respectively. The change in our effective income tax rate from the prior year rate was primarily due to the changes in the mix of taxable income and losses within our various subsidiaries resulting primarily from the impairment charges. Certain subsidiaries had state taxable income which resulted in state income tax expense; however, other subsidiaries with state tax losses have no state income tax benefits based upon the valuation allowances that we have recorded in connection with state net operating loss carryforwards.

Year Ended December 31, 2009 vs. Year Ended December 31, 2008

Admissions revenue was $24,741,000 in 2009 as compared to $31,034,000 in 2008. We promoted fourteen major events during 2009 as compared to fifteen during 2008. The $6,293,000 decrease was primarily related to lower admissions revenue at our NASCAR event weekends at Dover International Speedway and to a lesser extent lower admissions at all other major events we promoted during 2009. We believe the decrease in attendance was attributable primarily to the general downturn in economic conditions, including those affecting disposable consumer income and corporate budgets such as employment, business conditions, interest rates and taxation rates. We believe that adverse economic trends, particularly credit availability, the decline in consumer confidence and the rise in unemployment have increasingly contributed to the decrease in attendance. Inclement weather during the September NASCAR event weekend at Dover International Speedway also negatively impacted attendance. Additionally, the decrease was partially attributable to a change in our major motorsports event schedule. The Indy Racing League event at our Nashville Superspeedway that we promoted during 2008 was not promoted in 2009.

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Event-related revenue was $17,971,000 in 2009 as compared to $25,652,000 in 2008. The $7,681,000 decrease was primarily related to lower sponsorship revenues at most events we promoted during 2009 and lower luxury suite rentals and concession sales at our NASCAR Sprint Cup Series events at Dover International Speedway we believe as a result of economic conditions. Additionally, the decrease was partially attributable to the change in our major motorsports event schedule.

Broadcasting revenue increased slightly from $27,532,000 in 2008 to $27,999,000 in 2009. The increase resulted entirely from higher broadcasting revenue for our NASCAR-sanctioned events promoted during 2009.

Operating and marketing expenses were $50,466,000 in 2009 as compared to $55,262,000 in 2008. The $4,796,000 decrease primarily related to cost savings initiatives implemented at all major events promoted in 2009 and a reduction in expenses due to lower revenues. Additionally, the decrease was partially attributable to the change in our major motorsports event schedule.

We had an earlier agreement of sale relative to our Memphis Motorsports Park facility which expired in September 2009, and as a result, we concluded in the third quarter of 2009 that it was necessary for us to review the carrying value of the long-lived assets of our Memphis facility for impairment. Based on the results of this analysis, we recorded a $7,478,000 non-cash impairment charge to write-down the carrying value of long-lived assets at our Memphis facility to fair value.

General and administrative expenses decreased slightly between 2009 and 2008 from $12,528,000 to $12,174,000. The decrease resulted primarily from cost saving initiatives.

Depreciation and amortization expense was $6,467,000 in 2009 as compared to $6,909,000 in 2008. The decrease resulted primarily from a reduction in our depreciable asset base resulting from impairment charges recorded in the third quarter of 2009 and the fourth quarter of 2008 and the cessation of depreciation expense at our Memphis facility which was classified as held-for-sale for a portion of 2009, partially offset by depreciation on assets placed in service in 2009 and 2008 related to our Monster Makeover project in Dover, Delaware.

Net interest expense decreased to $2,110,000 in 2009 as compared to $3,995,000 in 2008. The decrease was due primarily to the reversal of $1,011,000 of previously recorded interest expense on certain unrecognized income tax benefits which are no longer subject to examination and to a lesser extent a lower average interest rate and lower average outstanding borrowings under our credit facility. Excluding the interest expense we record on certain unrecognized income tax benefits, our net interest expense was $2,795,000 in 2009 as compared to $3,385,000 in 2008.

Loss on sale of investments was $92,000 in 2009 and related solely to losses on the sale of available-for-sale securities.

Our effective income tax rates for 2009 and 2008 were 25.5% and 21.2%, respectively. The change in our effective income tax rate from the prior year rate was primarily due to the changes in the mix of taxable income and losses within our various subsidiaries. Certain subsidiaries had state taxable income which resulted in state income tax expense; however, other subsidiaries with state tax losses have no state income tax benefits due to the valuation allowances that we have recorded in connection with state net operating loss carryforwards.

Liquidity and Capital Resources

Our operations are seasonal in nature with a majority of our motorsports events occurring during the second and third quarters. However, our cash flows from operating activities are more evenly spread throughout the year, primarily due to the impact of advance ticket sales and other event-related cash receipts, such as sponsorship and luxury suite rentals. The non-cash impairment charges we recorded in 2010, 2009 and 2008 had no impact on our liquidity for the three years ended December 31, 2010.

Net cash provided by operating activities was $966,000 in 2010 as compared to $5,253,000 in 2009. The decrease was primarily due to the larger operating loss and lower receipts from advanced ticket sales.

Net cash provided by investing activities was $5,366,000 in 2010 as compared to net cash used in investing activities of $2,024,000 in 2009. Capital expenditures were $488,000 in 2010 compared with $1,912,000 in 2009. The 2010 additions related primarily to payments for concessions equipment and facility improvements. The 2009 additions related primarily to the Monster Makeover project, consisting primarily of racetrack improvements at our Dover facility. During 2010, we received $398,000 of insurance proceeds to cover damage to grandstands at our Memphis facility. Changes in our restricted cash accounts were $5,333,000 and $114,000 for 2010 and 2009, respectively. On July 21, 2010, we redeemed all of the outstanding SWIDA bonds. Subsequent to redeeming the SWIDA bonds, the remaining restricted cash was returned to us by the trustee.

Net cash used in financing activities was $6,418,000 in 2010 as compared to $3,362,000 in 2009. We had net repayments on our outstanding line of credit of $2,800,000 in 2010 as compared to $1,200,000 in 2009. Repayments of our outstanding SWIDA bonds were $2,986,000 for 2010 as compared to $1,127,000 for 2009. We incurred $167,000 of premium and fees associated with the SWIDA bond redemption during the third quarter of 2010. We paid $733,000 in cash dividends in 2009. No dividends were paid in 2010.

On July 29, 2009, our Board of Directors voted to suspend the declaration of regular quarterly cash dividends on all classes of our common stock. Dividends are prohibited by our credit facility.

At December 31, 2010, Dover Motorsports, Inc. and all of its wholly owned subsidiaries, as co-borrowers, were parties to a $68,000,000 secured revolving credit agreement with a bank group. The maximum borrowing limit under the facility reduces to $65,000,000 as of June 1, 2011 and $63,000,000 as of October 1, 2011 and the facility expires January 1, 2012. There was $38,200,000 outstanding under the credit facility at December 31, 2010, at a weighted average interest rate of 4.6%. The credit agreement is secured by all of our assets. It provides for seasonal funding needs, capital improvements, letter of credit requirements and other general corporate purposes. On October 28, 2010, we amended the credit agreement to revise certain financial covenants effective for the September 30, 2010 period and for the subsequent two quarterly measurement periods under the agreement, and to revise certain definitions. Interest is based, at our option, upon LIBOR plus a margin that varies between 300 and 400 basis points (400 basis points at December 31, 2010) depending on the ratio of funded debt to earnings before interest, taxes, depreciation and amortization (the leverage ratio) or upon the base rate (the greater of the prime rate, the federal funds rate plus 0.5% or the daily LIBOR rate plus 1.0%) plus a margin that varies between 200 and 300 basis points (300 basis points at December 31, 2010) depending on the leverage ratio. The terms of the credit facility contain certain covenants including minimum tangible net worth, fixed charge coverage and maximum funded debt to earnings before interest, taxes, depreciation and amortization. In addition, the credit agreement includes a material adverse change clause and prohibits the payment of dividends by us. The credit facility also provides that if we default under any other loan agreement, that would be a default under this credit facility. At December 31, 2010, we were in compliance with the terms of the credit facility.

Material adverse changes in our results of operations could impact our ability to maintain financial ratios necessary to satisfy these requirements. After consideration of stand-by letters of credit outstanding, the remaining maximum borrowings available pursuant to the credit facility were $8,448,000 at December 31, 2010; however, in order to maintain compliance with the required quarterly debt covenant calculations as of December 31, 2010 only $3,844,000 could have been borrowed as of that date. We expect to be in compliance with the financial covenants, and all other covenants, for all measurement periods during the next twelve months.

Our current credit agreement is scheduled to mature on January 1, 2012. We are currently evaluating possible options to address the expiration of the credit facility including refinancing with a new credit facility or other available financing options. We believe that we will be able to obtain sufficient financing to address the credit facility expiration.

In November 2010, we announced the closing of our Gateway facility. The Gateway facility is located on approximately 290 acres of land in Madison, Illinois and the racetrack is primarily on leased property. We had long-term leases for approximately 150 acres with four landlords. We also own approximately 140 acres near the Gateway facility. In February 2011, three of the four landlords agreed to terminate the land leases in exchange for 18.5 acres of owned real estate and our agreement to abandon all improvements and certain personal property (including the racetrack) on the leased land. As a result, we recorded an expense for facility exit costs of $324,000 at December 31, 2010 primarily to record a liability for the value of the real property we conveyed to the landlords

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in connection with terminating the leases. As part of the lease termination agreement with one of the landlords, we provided a six month purchase option on the remaining approximately 120 acres of owned land at $10,000 per acre, which approximates our carrying value.

We closed our Memphis Motorsports Park facility in October 2009 and executed an agreement to sell it in December 2010. The real estate sale closed on January 31, 2011. After closing costs and including the proceeds from the separate sale of all personal property at the facility, our net proceeds were approximately $2,000,000, all of which was used to pay down indebtedness of the Memphis facility. Since the carrying amount of the long-lived assets of the Memphis facility exceeded the sales price, we recognized a non-cash impairment charge of $809,000 in the fourth quarter of 2010.

Cash provided by operating activities is expected to substantially fund our capital expenditures. Based on current business conditions, we expect to spend approximately $500,000 on capital expenditures during 2011. Additionally, we expect to contribute approximately $700,000 to our pension plans for 2011. We expect continued cash flows from operating activities and funds available from our credit agreement to provide for our working capital needs and capital spending requirements at least through the next twelve months and also provide for our long-term liquidity.

Contractual Obligations

At December 31, 2010, we had the following contractual obligations and other commercial commitments:

			Payments Due by Period		
	Total	**2011**	**2012 2013**	**2014 2015**	**Thereafter**
Revolving line of credit	$ 38,200,000	$	$ 38,200,000	$	$
Estimated interest payments on revolving line of credit[a]	1,696,000	1,696,000			
Operating leases	114,000	51,000	37,000	25,000	1,000
Pension contributions[b]	700,000	700,000			
Total contractual cash obligations	$ 40,710,000	$ 2,447,000	$ 38,237,000	$ 25,000	$ 1,000

(a) The future interest payments on our revolving credit agreement were estimated using the current outstanding principal as of December 31, 2010 and related interest rates.

(b) We expect to contribute approximately $700,000 to our pension plans for 2011. For years subsequent to 2011, we are unable to estimate what our pension contributions will be.

In September 1999, the Sports Authority of the County of Wilson (Tennessee) issued $25,900,000 in Variable Rate Tax Exempt Infrastructure Revenue Bonds, Series 1999, to acquire, construct and develop certain public infrastructure improvements which benefit the operation of Nashville Superspeedway, of which $21,000,000 was outstanding at December 31, 2010. Annual principal payments range from $700,000 in September 2011 to $1,600,000 in 2029 and are payable solely from sales taxes and incremental property taxes generated from the facility. These bonds are direct obligations of the Sports Authority and are therefore not recorded on our consolidated balance sheet. If the sales taxes and incremental property taxes are insufficient for the payment of principal and interest on the bonds, we would become responsible for the difference. We are exposed to fluctuations in interest rates for these bonds. A significant increase in interest rates could result in us being responsible for debt service payments not covered by the sales and incremental property taxes generated from the facility. In the event we were unable to make the payments, they would be made pursuant to a $21,352,000 irrevocable direct-pay letter of credit issued by our bank group.

We believe that the sales taxes and incremental property taxes generated from the facility will continue to satisfy the necessary debt service requirements of the bonds through the maturity date in 2029. As of December 31, 2010 and 2009, $1,200,000 and $915,000, respectively, was available in the sales and incremental property tax fund maintained by the Sports Authority to pay the remaining principal and interest due under the bonds. During 2010, we paid $1,038,000 into the sales and incremental property tax fund and $753,000 was deducted from the fund for principal and interest payments. If the debt service is not satisfied from the sales and incremental property taxes generated from the facility, a portion of the bonds would become our liability. If we fail to maintain the letter of credit that secures the bonds or we allow an uncured event of default to exist under our reimbursement agreement relative to the letter of credit, the bonds would be immediately redeemable.

In November 2010, we announced the closing of our Gateway facility. The Gateway facility is located on approximately 290 acres of land in Madison, Illinois and the racetrack is primarily on leased property. We had long-term leases for approximately 150 acres with four landlords. We also own approximately 140 acres near the Gateway facility. In February 2011, three of the four landlords agreed to terminate the land leases in exchange for 18.5 acres of owned real estate and our agreement to abandon all improvements and certain personal property (including the racetrack) on the leased land. As a result, we no longer have contractual obligations related to these leases and they have been excluded from the contractual obligations disclosure.

We have not included our non current income taxes payable of $1,241,000 which is classified in accordance with the provisions of ASC Topic 740, *Income Taxes,* in the contractual obligations disclosure since we cannot reasonably estimate whether or when a cash settlement for uncertain tax positions would occur. See NOTE 7 Income Taxes in the notes to the consolidated financial statements for further discussion.

Related Party Transactions

See NOTE 11 Related Party Transactions in the notes to the consolidated financial statements included elsewhere in this document.

Critical Accounting Policies

The accounting policies described below are those we consider critical in preparing our consolidated financial statements. These policies include significant estimates made by management using information available at the time the estimates are made. As described below, these estimates could change materially if different information or assumptions were used.

Income Taxes

Income taxes are accounted for under the asset and liability method. Deferred tax assets and liabilities are recognized for the estimated future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases and operating losses. Deferred tax assets and liabilities are measured using enacted tax rates in effect for the year in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in the period that includes the enactment date. We record a valuation allowance to reduce our deferred tax assets to the amount that is more likely than not to be realized. As of December 31, 2010, our valuation allowance net of federal income taxes was $10,424,000, which increased by $985,000 in 2010, on deferred tax assets related to state net operating loss carry-forwards. These state net operating losses are related to our Midwest facilities that have not produced taxable income. In the event that our Midwest facilities continue to generate losses for state income tax purposes in the future, our valuation allowance will increase to offset those income tax benefits. We have considered ongoing prudent and feasible tax planning strategies in assessing the need for a valuation allowance. In the event we were to determine that we would be able to realize all or a portion of these deferred tax assets, an adjustment to the valuation allowance would increase earnings in the period such determination was made. Likewise, should we determine that we would not be able to realize all or a portion of our remaining deferred tax assets in the future, an adjustment to the valuation allowance would be charged to earnings in the period such determination was made.

Property and Equipment

Property and equipment are recorded at cost. Depreciation is provided for financial reporting purposes using the straight-line method over estimated useful lives ranging from 3 to 10 years for furniture, fixtures and equipment and up to 40 years for facilities. These estimates require assumptions that are believed to be reasonable. We perform reviews for impairment of long-lived assets whenever events or changes in circumstances indicate that the carrying value of an asset may not be recoverable. An impairment loss is measured as the amount by which the

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carrying amount of the asset exceeds its fair value. Generally, fair value is determined using valuation techniques such as the comparable sales approach. Historically the impairment assessment for track facilities has also considered the cost approach valuation technique, which gives specific consideration to the value of the track land plus the contributory value to the improvements. The primary economic assumptions used in the valuation techniques include: (i) land value which is estimated by comparable transactions; (ii) the contributory value of the track facilities calculated by estimated replacement costs, less economic depreciation; and (iii) that the highest and best use for the facilities is as a race track due to the contributory value of the improvements. Changes to these assumptions can have a significant effect on the outcome of future impairment tests and as a result, future valuations could differ significantly from current estimates. See NOTE 3 Impairment Charges in the notes to the consolidated financials statements for further discussion.

Accrued Pension Cost

The benefits provided by our defined-benefit pension plans are based on years of service and employee s remuneration over their employment with us. Accrued pension costs are developed using actuarial principles and assumptions which consider a number of factors, including estimates for the discount rate, assumed rate of compensation increase, and expected long-term rate of return on assets. Changes in these estimates would impact the amounts that we record in our consolidated financial statements.

Recent Accounting Pronouncements

See NOTE 2 Summary of Significant Accounting Policies of the consolidated financial statements included elsewhere in this document for a description of recent accounting pronouncements including, if applicable, the respective expected dates of adoption and effects on results of operations, financial condition and cash flows.

Factors That May Affect Operating Results; Forward-Looking Statements

This report and the documents incorporated by reference may contain forward-looking statements. In Item 1A of this report, we disclose the important factors that could cause our actual results to differ from our expectations.

Item 7A. Quantitative And Qualitative Disclosures About Market Risk

Not applicable.

Item 8. Financial Statements And Supplementary Data

Our consolidated financial statements and the Report of Independent Registered Public Accounting Firm included in this report are shown on the Index to Consolidated Financial Statements on page 32.

Item 9. Changes In And Disagreements With Accountants On Accounting And Financial Disclosure

None.

Item 9A. Controls and Procedures

Our management is responsible for the preparation, integrity and objectivity of the consolidated financial statements and other financial information included in this Form 10-K. The consolidated financial statements have been prepared in conformity with U.S. generally accepted accounting principles and reflect the effects of certain estimates and judgments made by management.

Our management also is responsible for establishing and maintaining a system of internal controls designed to provide reasonable assurance that assets are safeguarded and transactions are properly recorded and executed in accordance with management s authorization. The system is regularly monitored by direct management review and by internal auditors who conduct an extensive program of audits throughout our organization. The Director of

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Internal Audit reports directly to the Audit Committee of our Board of Directors. We have confidence in our financial reporting, the underlying system of internal controls, and our people, who are objective in their responsibilities and operate under our Code of Business Conduct and with the highest level of ethical standards. These standards are a key element of our control system.

The Audit Committee of our Board of Directors, which is comprised entirely of independent directors, has direct and private access to and meets regularly with management, our internal auditors and our independent registered public accounting firm to review accounting, reporting, auditing and internal control matters.

Management, including our Chief Executive Officer and Chief Financial Officer, does not expect that our internal controls will prevent or detect all errors and all fraud. A control system, no matter how well designed and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of internal controls can provide absolute assurance that all control issues and instances of fraud, if any, have been detected. Also, any evaluation of the effectiveness of controls in future periods are subject to the risk that those internal controls may become inadequate because of changes in business conditions, or that the degree of compliance with the policies or procedure may deteriorate.

(a) Evaluation of Disclosure Controls and Procedures

We have established disclosure controls and procedures to ensure that relevant, material information is made known to the officers who certify our financial reports and to other members of senior management and the Board of Directors.

Based on their evaluation as of December 31, 2010, our Chief Executive Officer and Chief Financial Officer have concluded that our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934) are effective to ensure that the information we are required to disclose in the reports that we file or submit under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in SEC rules and forms.

(b) Management s Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting. We conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on our evaluation, management concluded that our internal control over financial reporting was effective as of December 31, 2010. KPMG LLP independently assessed the effectiveness of our internal control over financial reporting as of December 31, 2010. KPMG LLP has issued their report which is included herein.

(c) Changes in Internal Control Over Financial Reporting

There have been no changes in our internal control over financial reporting during the fiscal quarter ended December 31, 2010 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

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(d) Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders

Dover Motorsports, Inc.:

We have audited Dover Motorsports, Inc. s (the Company s) internal control over financial reporting as of December 31, 2010, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying *Management s Report on Internal Control Over Financial Reporting (Item 9A(b))*. Our responsibility is to express an opinion on the effectiveness of the Company s internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit 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 audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

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 (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) 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 (3) 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.

In our opinion, Dover Motorsports, Inc. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2010, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Dover Motorsports, Inc. and subsidiaries as of December 31, 2010 and 2009, and the related consolidated statements of operations and comprehensive loss and cash flows for each of the years in the three-year period ended December 31, 2010, and our report dated March 15, 2011 expressed an unqualified opinion on those consolidated financial statements.

KPMG LLP

Philadelphia, Pennsylvania

March 15, 2011

Item 9B. Other Information
None.

Part III

Item 10. Directors, Executive Officers And Corporate Governance
Except as presented below, biographical information relating to our directors and executive officers, information regarding our audit committee financial experts and information on Section 16(a) Beneficial Ownership Reporting Compliance called for by this Item 10 are incorporated by reference to our Proxy Statement to be filed pursuant to Regulation 14A for the Annual Meeting of Stockholders to be held on April 27, 2011.

We have a Code of Business Conduct applicable to all of our employees, including our Chief Executive Officer and Chief Financial Officer. We also have a Code of Business Conduct and Ethics for Directors and Executive Officers and Related Party Transactions Policy applicable to all directors and executive officers. Copies of these Codes and other corporate governance documents are available on our website at http://www.dovermotorsports.com under the heading, Investor Relations. We will post on our website any amendments to, or waivers from, these Codes as required by law.

Executive Officers of the Registrant. As of December 31, 2010, our executive officers were:

Name	Position	Age	Term of Office
Denis McGlynn	President and Chief Executive Officer	64	11/79 to date
Michael A. Tatoian	Executive Vice President	50	01/07 to date
Timothy R. Horne	Sr. Vice President-Finance and Chief Financial Officer	44	4/08 to date
Klaus M. Belohoubek	Sr. Vice President-General Counsel and Secretary	51	7/99 to date
Thomas Wintermantel	Treasurer and Assistant Secretary	52	7/02 to date

Our Chairman of the Board, Henry B. Tippie, is a non-employee director and, therefore, not an executive officer. Mr. Tippie has served as Chairman of the Board for 11 years and prior to that served as Vice Chairman of the Board. Mr. Tippie also serves as Chairman of the Board to Gaming as a non-employee director.

Denis McGlynn has served as our President and Chief Executive Officer for 31 years. Mr. McGlynn also serves as President and Chief Executive Officer to Gaming.

Michael A. Tatoian joined us as Executive Vice President in January 2007. Mr. Tatoian has more than 22 years experience in professional sports ownership, management and operations. He served as Chief Executive Officer and Managing Partner of Victory Sports Group, LLC, where he oversaw the development and management of professional sports organizations, including minor league baseball, minor league hockey and a NASCAR Nationwide Series team. Mr. Tatoian also served as Chief Operating Officer of United Sports Ventures, Inc., an umbrella sports company that owned and operated eight minor league teams.

Timothy R. Horne has been Sr. Vice President-Finance and Chief Financial Officer since April 2008. Mr. Horne was the Chief Financial Officer of Dover Motorsports, Inc. from 1996 until its 2002 spin-off of Gaming. He has served as Sr. Vice President-Finance, Treasurer and Chief Financial Officer of Gaming since 2002, but has been actively involved in the financial departments of both companies.

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Klaus M. Belohoubek has been Sr. Vice President-General Counsel and Secretary since 1999 and has provided us legal representation in various capacities since 1990. Mr. Belohoubek also serves as Sr. Vice President-General Counsel and Secretary of Gaming.

Thomas Wintermantel has been Treasurer and Assistant Secretary since July 2002. Previously, Mr. Wintermantel was the Financial Vice President and Treasurer of John W. Rollins & Associates, Financial Vice President of Rollins Jamaica, Ltd. and President and Director of the John W. Rollins Foundation.

Item 11. Executive Compensation

The information called for by this Item 11 is incorporated by reference to our Proxy Statement to be filed pursuant to Regulation 14A for the Annual Meeting of Stockholders to be held on April 27, 2011.

Item 12. Security Ownership Of Certain Beneficial Owners And Management And Related Stockholder Matters

The information called for by this Item 12 is incorporated by reference to our Proxy Statement to be filed pursuant to Regulation 14A for the Annual Meeting of Stockholders to be held on April 27, 2011.

Equity Compensation Plan Information

We have a 1996 stock option plan (the 1996 Plan) which provided for the grant of stock options to our officers and key employees. Our Board of Directors froze the 1996 Plan and no additional option grants may be made under the 1996 Plan. We have a 2004 stock incentive plan (the 2004 Plan) which provides for the grant of up to 1,500,000 shares of common stock to our officers and key employees through stock options and/or awards valued in whole or in part by reference to our common stock, such as restricted stock awards. Refer to NOTE 9 Stockholders Equity in the notes to the consolidated financial statements included elsewhere in this document for further discussion.

Securities authorized for issuance under equity compensation plans at December 31, 2010 are as follows:

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights (a)	Weighted-average exercise price of outstanding options, warrants and rights (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c)
Equity compensation plans approved by security holders	205,000	$ 4.68	666,070
Equity compensation plans not approved by security holders			
Total	205,000	$ 4.68	666,070

Item 13. Certain Relationships And Related Transactions, And Director Independence

The information called for by this Item 13 is incorporated by reference to our Proxy Statement to be filed pursuant to Regulation 14A for the Annual Meeting of Stockholders to be held on April 27, 2011.

Item 14. Principal Accounting Fees And Services

The information called for by this Item 14 is incorporated by reference to our Proxy Statement to be filed pursuant to Regulation 14A for the Annual Meeting of Stockholders to be held on April 27, 2011.

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Part IV

Item 15. Exhibits, Financial Statement Schedules

(a)(1) Financial Statements See accompanying Index to Consolidated Financial Statements on page 32.

(2) Financial Statement Schedules None.

(3) Exhibits:

2.1 Share Exchange Agreement and Plan of Reorganization dated June 14, 1996 between Dover Motorsports, Inc. (formerly known as Dover Downs Entertainment, Inc.), Dover Downs, Inc., Dover Downs International Speedway, Inc. and the shareholders of Dover Downs, Inc. (incorporated herein by reference to Exhibit 2.1 to the Registration Statement, Number 333-8147, on Form S-1 dated July 15, 1996, which was declared effective on October 3, 1996).

2.2 Agreement and Plan of Merger, dated as of March 26, 1998, by and among Dover Motorsports, Inc. (formerly known as Dover Downs Entertainment, Inc.), FOG Acquisition Corp., and Grand Prix Association of Long Beach (incorporated herein by reference to Exhibit 2.1 to the Registration Statement, Number 333-53077, on Form S-4 dated May 19, 1998).

2.3 Amended and Restated Agreement Regarding Distribution and Plan of Reorganization, dated as of February 15, 2002, by and between Dover Motorsports, Inc. (formerly known as Dover Downs Entertainment, Inc.) and Dover Downs Gaming & Entertainment, Inc. (incorporated herein by reference to Exhibit 2.1 to the Registration Statement of Dover Downs Gaming & Entertainment, Inc., Number 1-16791, on Form 10 dated February 26, 2002, which was declared effective on March 7, 2002).

3.1 Restated Certificate of Incorporation of Dover Motorsports, Inc. (formerly known as Dover Downs Entertainment, Inc.), dated March 10, 2000 (incorporated herein by reference to Exhibit 3.1 to the Quarterly Report on Form 10-Q dated April 28, 2000).

3.2 Amended and Restated By-laws of Dover Motorsports, Inc. dated April 1, 2002 (incorporated herein by reference to Exhibit 3.1 to the Quarterly Report on Form 10-Q dated May 10, 2002).

4.1 Rights Agreement dated as of June 14, 1996 between Dover Motorsports, Inc. (formerly known as Dover Downs Entertainment, Inc.) and ChaseMellon Shareholder Services, L.L.C. (incorporated herein by reference to Exhibit 4.2 to the Registration Statement, Number 333-8147, on Form S-1 dated July 15, 1996, which was declared effective on October 3, 1996).

10.1 Credit Agreement between Dover Motorsports, Inc., Dover International Speedway, Inc., Gateway International Motorsports Corporation, Gateway International Services Corporation, Memphis International Motorsports Corporation, M & N Services Corp., Nashville Speedway, USA, Inc. and Grand Prix Association of Long Beach, Inc. and Mercantile-Safe Deposit and Trust Company, as agent, dated as of February 17, 2004 (incorporated herein by reference to Exhibit 10.1 to the Annual Report on Form 10-K dated March 10, 2004).

10.2 Amendment No. 2 to the Credit Agreement between Dover Motorsports, Inc., Dover International Speedway, Inc., Gateway International Motorsports Corporation, Gateway International Services Corporation, Memphis International Motorsports Corporation, M & N Services Corp., Nashville Speedway, USA, Inc. and Grand Prix Association of Long Beach, Inc. and Mercantile-Safe Deposit and Trust Company, as agent, dated as of July 28, 2004 (incorporated herein by reference to Exhibit 10.8 to the Quarterly Report on Form 10-Q dated August 6, 2004).

10.3 Amendment No. 3 to the Credit Agreement between Dover Motorsports, Inc., Dover International Speedway, Inc., Gateway International Motorsports Corporation, Gateway International Services Corporation, Memphis International Motorsports Corporation, M & N Services Corp., Nashville Speedway, USA, Inc. and Grand

	Prix Association of Long Beach, Inc. and Mercantile-Safe Deposit and Trust Company, as agent, dated as of February 16, 2005 (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K dated February 25, 2005).
10.4	Amendment No. 4 to Credit Agreement among, Dover Motorsports, Inc., Dover International Speedway, Inc., Gateway International Motorsports Corporation, Gateway International Services Corporation, Memphis International Motorsports Corporation, M & N Services Corp., Nashville Speedway, USA, Inc., Midwest Racing, Inc., Mercantile-Safe Deposit and Trust Company, as agent, and various other lenders, dated as of August 5, 2005 (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K dated August 8, 2005).
10.5	Amendment No. 5 to the Credit Agreement between Dover Motorsports, Inc., Dover International Speedway, Inc., Gateway International Motorsports Corporation, Gateway International Services Corporation, Memphis International Motorsports Corporation, M & N Services Corp., and Nashville Speedway, USA, Inc. and Mercantile-Safe Deposit and Trust Company, as agent, dated as of October 12, 2005 (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K dated October 12, 2005).
10.6	Amendment No. 6 to the Credit Agreement between Dover Motorsports, Inc., Dover International Speedway, Inc., Gateway International Motorsports Corporation, Gateway International Services Corporation, Memphis International Motorsports Corporation, M & N Services Corp., and Nashville Speedway, USA, Inc. and Mercantile-Safe Deposit and Trust Company, as agent, dated as of May 8, 2006 (incorporated herein by reference to Exhibit 10.6 to the Annual Report on Form 10-K dated March 6, 2007).
10.7	Amendment No. 7 to the Credit Agreement between Dover Motorsports, Inc., Dover International Speedway, Inc., Gateway International Motorsports Corporation, Gateway International Services Corporation, Memphis International Motorsports Corporation, M & N Services Corp., and Nashville Speedway, USA, Inc. and Mercantile-Safe Deposit and Trust Company, as agent, dated as of November 8, 2006 (incorporated herein by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q dated November 9, 2006).
10.8	Amendment No. 8 to the Credit Agreement between Dover Motorsports, Inc., Dover International Speedway, Inc., Gateway International Motorsports Corporation, Memphis International Motorsports Corporation, and Nashville Speedway, USA, Inc. and Mercantile-Safe Deposit and Trust Company, as agent, dated as of May 1, 2007 (incorporated herein by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q dated May 4, 2007).
10.9	Amendment No. 9 to the Credit Agreement between Dover Motorsports, Inc., Dover International Speedway, Inc., Gateway International Motorsports Corporation, Memphis International Motorsports Corporation, and Nashville Speedway, USA, Inc. and PNC Bank, National Association, as agent, dated as of May 21, 2008 (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K dated May 22, 2008).
10.10	Amendment No. 10 to the Credit Agreement between Dover Motorsports, Inc., Dover International Speedway, Inc., Gateway International Motorsports Corporation, Memphis International Motorsports Corporation, and Nashville Speedway, USA, Inc. and PNC Bank, National Association, as agent, dated as of June 30, 2009 (incorporated herein by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q dated August 10, 2009).
10.11	Amendment No. 11 to the Credit Agreement between Dover Motorsports, Inc., Dover International Speedway, Inc., Gateway International Motorsports Corporation, Memphis International Motorsports Corporation, Nashville Speedway, USA, Inc., and Midwest Racing, Inc. and PNC Bank, National Association, as agent, dated as of August 21, 2009 (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K dated August 21, 2009).

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10.12	Amendment No. 12 to the Credit Agreement between Dover Motorsports, Inc., Dover International Speedway, Inc., Gateway International Motorsports Corporation, Memphis International Motorsports Corporation, Nashville Speedway, USA, Inc., and Midwest Racing, Inc. and PNC Bank, National Association, as agent, dated as of August 3, 2010 (incorporated herein by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q dated August 6, 2010).
10.13	Amendment No. 13 to the Credit Agreement between Dover Motorsports, Inc., Dover International Speedway, Inc., Gateway International Motorsports Corporation, Memphis International Motorsports Corporation, Nashville Speedway, USA, Inc., and Midwest Racing, Inc. and PNC Bank, National Association, as agent, dated as of October 28, 2010 (incorporated herein by reference to Exhibit 10.1 to the Form 8-K filed on November 2, 2010).
10.14	Dover Motorsports, Inc. (formerly known as Dover Downs Entertainment, Inc.) 1996 Stock Option Plan (incorporated herein by reference to Exhibit 10.8 to the Registration Statement, Number 333-8147, on Form S-1 dated July 15, 1996, which was declared effective on October 3, 1996).
10.15	Employee Benefits Agreement, dated as of January 15, 2002, by and between Dover Motorsports, Inc. (formerly known as Dover Downs Entertainment, Inc.) and Dover Downs Gaming & Entertainment, Inc. (incorporated herein by reference to Exhibit 10.2 to the Registration Statement of Dover Downs Gaming & Entertainment, Inc., Number 1-16791, on Form 10 dated January 16, 2002, which was declared effective on March 7, 2002).
10.16	Transition Support Services Agreement, dated as of January 15, 2002, by and between Dover Motorsports, Inc. (formerly known as Dover Downs Entertainment, Inc.) and Dover Downs Gaming & Entertainment, Inc. (incorporated herein by reference to Exhibit 10.3 to the Registration Statement of Dover Downs Gaming & Entertainment, Inc., Number 1-16791, on Form 10 dated January 16, 2002, which was declared effective on March 7, 2002).
10.17	Tax Sharing Agreement, dated as of January 15, 2002, by and between Dover Motorsports, Inc. (formerly known as Dover Downs Entertainment, Inc.) and Dover Downs Gaming & Entertainment, Inc. (incorporated herein by reference to Exhibit 10.4 to the Registration Statement of Dover Downs Gaming & Entertainment, Inc., Number 1-16791, on Form 10 dated January 16, 2002, which was declared effective on March 7, 2002).
10.18	Real Property Agreement, dated as of January 15, 2002, by and between Dover Motorsports, Inc. (formerly known as Dover Downs Entertainment, Inc.) and Dover Downs Gaming & Entertainment, Inc. (incorporated herein by reference to Exhibit 10.5 to the Registration Statement of Dover Downs Gaming & Entertainment, Inc., Number 1-16791, on Form 10 dated January 16, 2002, which was declared effective on March 7, 2002).
10.19	Sanction Agreement between Dover International Speedway, Inc. and National Association for Stock Car Auto Racing for May 2010 Sprint Cup Series event (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K dated November 9, 2009).
10.20	Sanction Agreement between Dover International Speedway, Inc. and National Association for Stock Car Auto Racing for September 2010 Sprint Cup Series event (incorporated herein by reference to Exhibit 10.2 to the Current Report on Form 8-K dated November 9, 2009).
10.21	Amended and Restated Employment and Non-Compete Agreement between Dover Motorsports, Inc. and Denis McGlynn dated February 13, 2006 (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K dated February 17, 2006).
10.22	Amended and Restated Employment and Non-Compete Agreement between Dover Motorsports, Inc. and Michael A. Tatoian dated July 26, 2007 (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K dated July 26, 2007).

10.23	Amended and Restated Employment and Non-Compete Agreement between Dover Motorsports, Inc. and Klaus M. Belohoubek dated February 13, 2006 (incorporated herein by reference to Exhibit 10.4 to the Current Report on Form 8-K dated February 17, 2006).
10.24	Amended and Restated Employment and Non-Compete Agreement between Dover Motorsports, Inc. and Thomas G. Wintermantel dated February 13, 2006 (incorporated herein by reference to Exhibit 10.5 to the Current Report on Form 8-K dated February 17, 2006).
10.25	Amended and Restated Employment and Non-Compete Agreement between Dover Motorsports, Inc. and Timothy R. Horne dated January 3, 2008 (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K dated January 4, 2008).
10.26	Non-Compete Agreement between Dover Motorsports, Inc. and Henry B. Tippie dated June 16, 2004 (incorporated herein by reference to Exhibit 10.6 to the Quarterly Report on Form 10-Q dated August 6, 2004).
10.27	Amendment to certain agreements between Dover Motorsports, Inc. and selected executives and directors (incorporated herein by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q dated November 5, 2008).
10.28	Dover Motorsports, Inc. 2004 Stock Incentive Plan (incorporated herein by reference to Exhibit A to our Proxy Statement filed on March 29, 2004).
10.29	Form of Incentive Stock Option Agreement Used with Dover Motorsports, Inc. 2004 Stock Incentive Plan (incorporated herein by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q dated November 3, 2004).
10.30	Form of Restricted Stock Grant Agreement Used with Dover Motorsports, Inc. 2004 Stock Incentive Plan (incorporated herein by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q dated November 3, 2004).
10.31	Lender s Consent Letter, dated May 23, 2005, under the Credit Agreement between Dover Motorsports, Inc., Dover International Speedway, Inc., Gateway International Motorsports Corporation, Gateway International Services Corporation, Memphis International Motorsports Corporation, M & N Services Corp., Nashville Speedway, USA, Inc., Grand Prix Association of Long Beach, Inc. and Mercantile-Safe Deposit and Trust Company, as agent (incorporated herein by reference to Exhibit 10.2 to the Current Report on Form 8-K dated May 26, 2005).
10.32	Stock Purchase Agreement dated January 28, 2009 between Midwest Racing, Inc. and Gulf Coast Entertainment, L.L.C. (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K dated January 30, 2009).
10.33	Description of Annual Salary and Certain Discretionary Incentives to Executive Officers (incorporated herein by reference to Item 1.01 to the Current Report on Form 8-K dated January 3, 2011).
21.1	Subsidiaries
23.1	Consent of Independent Registered Public Accounting Firm
24.1	Powers of Attorney for Directors
31.1	Certification of Chief Executive Officer pursuant to Rule 13a-14(a)
31.2	Certification of Chief Financial Officer pursuant to Rule 13a-14(a)

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32.1	Certification of Chief Executive Officer Pursuant to 18 U.S.C. Sec. 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2	Certification of Chief Financial Officer Pursuant to 18 U.S.C. Sec. 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
99.1	Audit Committee Charter of Dover Motorsports, Inc. (incorporated herein by reference to Exhibit A to our Proxy Statement dated March 30, 2010).

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Signatures

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

DATED: March 15, 2011

Dover Motorsports, Inc.
Registrant

BY: /s/ Denis McGlynn
Denis McGlynn
President, Chief Executive Officer and Director

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated:

/s/ Denis McGlynn Denis McGlynn	*President, Chief Executive Officer and Director* (Principal Executive Officer)	March 15, 2011
/s/ Timothy R. Horne Timothy R. Horne	*Sr. Vice President Finance, and Chief Financial Officer* (Principal Financial and Accounting Officer)	March 15, 2011

The Directors of the registrant (listed below) executed a power of attorney appointing Denis McGlynn and Timothy R. Horne their attorneys-in-fact, empowering them to sign this report on their behalf.

/s/ Henry B. Tippie Henry B. Tippie	*Chairman of the Board*	March 15, 2011
/s/ Kenneth K. Chalmers Kenneth K. Chalmers	*Director and Chairman of the Audit Committee*	March 15, 2011
/s/ Patrick J. Bagley Patrick J. Bagley	*Director*	March 15, 2011
/s/ John W. Rollins, Jr. John W. Rollins, Jr.	*Director*	March 15, 2011
/s/ Jeffrey W. Rollins	*Director*	March 15, 2011

Jeffrey W. Rollins		
/s/ R. Randall Rollins	*Director*	March 15, 2011
R. Randall Rollins		
/s/ Eugene W. Weaver	*Director*	March 15, 2011
Eugene W. Weaver		
/s/ Denis McGlynn	*As Attorney-in-Fact*	March 15, 2011
Denis McGlynn	*and Director*	

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders

Dover Motorsports, Inc.:

We have audited the accompanying consolidated balance sheets of Dover Motorsports, Inc. and subsidiaries (the Company) as of December 31, 2010 and 2009, and the related consolidated statements of operations and comprehensive loss and cash flows for each of the years in the three-year period ended December 31, 2010. These consolidated financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these consolidated financial statements based on our 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 audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Dover Motorsports, Inc. and subsidiaries as of December 31, 2010 and 2009, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2010, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Dover Motorsports, Inc. s internal control over financial reporting as of December 31, 2010, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated March 15, 2011 expressed an unqualified opinion on the effectiveness of the Company s internal control over financial reporting.

KPMG LLP

Philadelphia, Pennsylvania

March 15, 2011

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DOVER MOTORSPORTS, INC.

CONSOLIDATED STATEMENTS OF OPERATIONS

AND COMPREHENSIVE LOSS

(in thousands, except per share data)

	Years ended December 31,		
	2010	**2009**	**2008**
Revenues:			
Admissions	$ 19,251	$ 24,741	$ 31,034
Event-related	15,010	17,971	25,652
Broadcasting	28,681	27,999	27,532
Other	18	167	61
	62,960	70,878	84,279
Expenses:			
Operating and marketing	43,641	50,466	55,262
Impairment charges	8,773	7,478	12,795
Facility exit costs	324		
General and administrative	13,254	12,174	12,528
Depreciation and amortization	6,190	6,467	6,909
	72,182	76,585	87,494
Gain from insurance settlement	398		
Operating loss	(8,824)	(5,707)	(3,215)
Interest income	17	14	83
Interest expense	(2,477)	(2,124)	(4,078)
Gain (loss) on sale of investments	6	(92)	
Loss on extinguishment of debt	(208)		
Loss before income tax benefit	(11,486)	(7,909)	(7,210)
Income tax benefit	3,313	2,014	1,531
Net loss	(8,173)	(5,895)	(5,679)
Unrealized gain (loss) on interest rate swap, net of income taxes		213	(64)
Unrealized gain (loss) on available-for-sale securities, net of income taxes	18	36	(86)
Reclassification adjustment for loss realized on available-for-sale securities, net of income taxes		55	
Change in pension net actuarial loss and prior service cost, net of income taxes	(239)	743	(1,360)
Comprehensive loss	$ (8,394)	$ (4,848)	$ (7,189)
Net loss per common share:			
Basic	$ (0.23)	$ (0.16)	$ (0.16)
Diluted	$ (0.23)	$ (0.16)	$ (0.16)

The Notes to the Consolidated Financial Statements are an integral part of these consolidated statements.

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DOVER MOTORSPORTS, INC.

CONSOLIDATED BALANCE SHEETS

(in thousands, except share and per share data)

	December 31, 2010	December 31, 2009
ASSETS		
Current assets:		
Cash and cash equivalents	$ 69	$ 155
Accounts receivable	839	1,260
Inventories	232	277
Prepaid expenses and other	1,732	1,528
Deferred income taxes	242	118
Current assets held for sale	1,875	2,800
Total current assets	4,989	6,138
Property and equipment, net	116,563	130,182
Restricted cash		5,333
Other assets, net	527	712
Deferred income taxes	206	164
Total assets	$ 122,285	$ 142,529
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities:		
Accounts payable	$ 146	$ 456
Accrued liabilities	3,151	2,986
Payable to Dover Downs Gaming & Entertainment, Inc.	18	5
Income taxes payable	123	199
Current portion of bonds payable		1,235
Deferred revenue	3,644	5,931
Total current liabilities	7,082	10,812
Revolving line of credit	38,200	41,000
Bonds payable		1,739
Liability for pension benefits	2,291	1,695
Other liabilities	121	875
Non current income taxes payable	1,241	3,269
Deferred income taxes	18,843	20,850
Total liabilities	67,778	80,240
Commitments and contingencies (see Notes to the Consolidated Financial Statements)		
Stockholders equity:		
Preferred stock, $.10 par value; 1,000,000 shares authorized; shares issued and outstanding: none		
Common stock, $.10 par value; 75,000,000 shares authorized; shares issued and outstanding: 18,197,552 and 18,065,166, respectively	1,820	1,806
Class A common stock, $.10 par value; 55,000,000 shares authorized; shares issued and outstanding: 18,510,975 and 18,510,975, respectively	1,851	1,851
Additional paid-in capital	101,541	100,943

Accumulated deficit	(49,167)	(40,994)
Accumulated other comprehensive loss	(1,538)	(1,317)
Total stockholders equity	54,507	62,289
Total liabilities and stockholders equity	$ 122,285	$ 142,529

The Notes to the Consolidated Financial Statements are an integral part of these consolidated statements.

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DOVER MOTORSPORTS, INC.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in thousands)

	Years ended December 31, 2010	2009	2008
Operating activities:			
Net loss	$ (8,173)	$ (5,895)	$ (5,679)
Adjustments to reconcile net loss to net cash provided by operating activities:			
Depreciation and amortization	6,190	6,467	6,909
Amortization of credit facility fees	501	229	175
Stock-based compensation	662	495	598
Deferred income taxes	(4,128)	(2,934)	(2,544)
Impairment charges	8,773	7,478	12,795
Gain from insurance settlement	(398)		
Loss on extinguishment of debt	208		
Facility exit costs	324		
Changes in assets and liabilities:			
Accounts receivable	421	690	(228)
Inventories	32	(4)	(88)
Prepaid expenses and other	(132)	212	50
Accounts payable	(223)	(148)	(72)
Accrued liabilities	(253)	(69)	(691)
Payable to/receivable from Dover Downs Gaming & Entertainment, Inc.	13	16	7
Income taxes payable/receivable	3	40	(120)
Deferred revenue	(2,287)	(1,031)	(1,727)
Other liabilities	(567)	(293)	663
Net cash provided by operating activities	966	5,253	10,048
Investing activities:			
Capital expenditures	(488)	(1,912)	(6,577)
Insurance proceeds	398		
Proceeds from sale of assets	129		
Restricted cash	5,333	(114)	(1,050)
Proceeds from sale of available-for-sale securities	179	335	
Purchase of available-for-sale securities	(185)	(333)	(50)
Net cash provided by (used in) investing activities	5,366	(2,024)	(7,677)
Financing activities:			
Borrowings from revolving line of credit	32,600	37,050	38,600
Repayments on revolving line of credit	(35,400)	(38,250)	(38,700)
Repayments of bonds payable	(2,986)	(1,127)	(108)
Dividends paid		(733)	(2,184)
Premium and fees on extinguishment of debt	(167)		
Repurchase of common stock	(50)	(19)	(137)
Proceeds from stock options exercised			216
Credit facility fees	(415)	(283)	(124)
Excess tax benefit on stock awards			27

Net cash used in financing activities	(6,418)	(3,362)	(2,410)
Net decrease in cash and cash equivalents	(86)	(133)	(39)
Cash and cash equivalents, beginning of year	155	288	327
Cash and cash equivalents, end of year	$ 69	$ 155	$ 288
Supplemental information:			
Interest paid	$ 2,748	$ 2,558	$ 3,380
Income tax payments	$ 812	$ 880	$ 1,107

The Notes to the Consolidated Financial Statements are an integral part of these consolidated statements.

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DOVER MOTORSPORTS, INC.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1 Business Operations

References in this document to we, us and our mean Dover Motorsports, Inc. and/or its wholly owned subsidiaries, as appropriate.

Dover Motorsports, Inc. is a public holding company that is a leading marketer and promoter of motorsports entertainment in the United States. Through our subsidiaries, we own and operate Dover International Speedway® in Dover, Delaware and Nashville Superspeedway® near Nashville, Tennessee. We closed Gateway International Raceway® near St. Louis, Missouri, after the 2010 race season and will not promote any future events there see further discussion below. These three facilities promoted 13 major events during 2010 under the auspices of two of the premier sanctioning bodies in motorsports the National Association for Stock Car Auto Racing (NASCAR) and the National Hot Rod Association (NHRA).

In 2010, we promoted the following major events:

- 2 NASCAR Sprint Cup Series events;
- 6 NASCAR Nationwide Series events;
- 4 NASCAR Camping World Truck Series events; and
- 1 NHRA event.

In 2011, we are scheduled to promote 9 major events, all of which will be sanctioned by NASCAR.

We derive a substantial portion of our revenues from admissions, event-related and broadcasting revenues attributable to our NASCAR-sanctioned events at Dover International Speedway which were held in May and September. Total revenues from these events were approximately 80% of total revenues for 2010 and approximately 70% for 2009 and 2008.

We closed our Memphis Motorsports Park facility in October 2009 and executed an agreement to sell it in December 2010. The real estate sale closed on January 31, 2011. After closing costs and including the proceeds from the separate sale of all personal property at the facility, our net proceeds were approximately $2,000,000. Since the carrying amount of the long-lived assets of the Memphis facility exceeded the sales price, we recognized a non-cash impairment charge of $809,000 in the fourth quarter of 2010. See NOTE 3 Impairment Charges.

In November 2010, we announced the closing of our Gateway facility. The Gateway facility is located on approximately 290 acres of land in Madison, Illinois and the racetrack is primarily on leased property. We had long-term leases for approximately 150 acres with four landlords. We also own approximately 140 acres near the Gateway facility. In February 2011, three of the four landlords agreed to terminate the land leases in exchange for 18.5 acres of owned real estate and our agreement to abandon all improvements and certain personal property (including the racetrack) on the leased land. As a result, we recorded an expense for facility exit costs of $324,000 at December 31, 2010 primarily to record a liability for the value of the real property we conveyed to the landlords in connection with terminating the leases. The liability is recorded in accrued liabilities in the consolidated balance sheet as of December 31, 2010. As part of the lease termination agreement with one of the landlords, we provided a six month purchase option on the remaining approximately 120 acres of owned land at $10,000 per acre, which approximates our carrying value.

We believe that our cash and cash equivalents, continued cash flows from operating activities and funds available from our credit agreement will provide for our working capital needs and capital spending requirements at least through the next twelve months. As disclosed in NOTE 6 Long-Term Debt our current credit agreement is scheduled to mature on January 1, 2012. We are currently evaluating possible options to address the expiration of the credit facility including refinancing with a new credit facility or other available financing options. We believe that we will be able to obtain sufficient financing to address the credit facility expiration.

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NOTE 2 Summary of Significant Accounting Policies

Basis of consolidation and presentation The accompanying consolidated financial statements include the accounts of Dover Motorsports, Inc. and our wholly owned subsidiaries. Intercompany transactions and balances have been eliminated.

Cash equivalents We consider as cash equivalents all highly-liquid investments with an original maturity of three months or less.

Investments Investments, which consist of mutual funds, are classified as available-for-sale and reported at fair-value in other assets in our consolidated balance sheets. Changes in fair value are reported in other comprehensive income (loss). See NOTE 9 Stockholders Equity and NOTE 10 Financial Instruments for further discussion.

Accounts receivable Accounts receivable are stated at their estimated collectible amount and do not bear interest.

Inventories Inventories of items for resale are stated at the lower of cost or market with cost being determined on the first-in, first-out basis.

Derivative instruments and hedging activities We are subject to interest rate risk on the variable component of the interest rate under our revolving credit agreement. Effective October 21, 2005, we entered into a $37,500,000 interest rate swap agreement. The agreement terminated on November 1, 2009. We designated the interest rate swap as a cash flow hedge. Changes in the fair value of the effective portion of the interest rate swap were recognized in other comprehensive (loss) income until the hedged item was recognized in earnings. See NOTE 6 Long-Term Debt and NOTE 10 Financial Instruments for further discussion.

Property and equipment Property and equipment is stated at cost. Depreciation is provided for financial reporting purposes using the straight-line method over the following estimated useful lives:

Facilities	10-40 years
Furniture, fixtures and equipment	3-10 years

Impairment of long-lived assets Long-lived assets are assessed for impairment whenever events or changes in circumstances indicate that the carrying value may not be recoverable. An impairment loss is measured as the amount by which the carrying amount of the asset exceeds its fair value. Generally, fair value is determined using valuation techniques such as the sales approach. Historically the impairment assessment for track facilities has also considered the cost approach valuation technique, which gives specific consideration to the value of the land plus contributory value to the improvements. See NOTE 3 Impairment Charges for further discussion.

Income taxes Deferred income taxes are provided on all differences between the tax basis of assets and liabilities and their reported amounts in the consolidated financial statements based upon enacted statutory tax rates in effect at the balance sheet date. We record a valuation allowance to reduce our deferred tax assets when uncertainty regarding their realizability exists. In assessing the realizability of deferred tax assets, management considers whether it is more likely than not that some portion or all of the deferred tax assets will not be realized. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during periods in which those temporary differences become deductible. Management considers the scheduled reversal of deferred tax liabilities, projected future taxable income and tax planning strategies in making this assessment. We recognize the effect of income tax positions only if those positions are more likely than not of being sustained. Recognized income tax positions are measured at the largest amount that is greater than 50% likely of being realized. Changes in recognition or measurement are reflected in the period in which the change in judgment occurs.

As further discussed in NOTE 7 Income Taxes, interest expense on uncertain income tax positions is being recorded in accordance with the provisions of Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC) Topic 740, *Income Taxes*. We record interest related to uncertain income tax positions in interest expense in the consolidated statements of operations and other liabilities in the consolidated balance sheets.

Revenue recognition We classify our revenues as admissions, event-related, broadcasting and other. Admissions revenue includes ticket sales for all Company events. Event-related revenue includes amounts received from sponsorship fees; luxury suite rentals; hospitality tent rentals and catering; concessions and souvenir sales and vendor commissions for the right to sell concessions and souvenirs at our facilities; sales of programs; track rentals and other event-related revenues. Broadcasting revenue includes rights fees obtained for television and radio broadcasts of events held at our speedways and ancillary media rights fees.

Revenues pertaining to specific events are deferred until the event is held. Concession and souvenir revenue are recorded at the time of sale. Revenues and related expenses from barter transactions in which we receive advertising or other goods or services in exchange for sponsorships of motorsports events are recorded at fair value. Barter transactions accounted for $848,000, $936,000 and $1,163,000 of total revenues for the years ended December 31, 2010, 2009 and 2008, respectively.

Under the terms of our sanction agreements, NASCAR retains 10% of the gross broadcast rights fees allocated to each NASCAR-sanctioned event as a component of its sanction fee. The remaining 90% is recorded as revenue. The event promoter is required to pay 25% of the gross broadcast rights fees to the event as part of the awards to the competitors, which we record as operating expenses.

We are responsible for collecting sales taxes from our customers on certain revenue generating activities and remitting these taxes to the appropriate governmental taxing authority. We include sales taxes in admissions and event-related revenues in our consolidated statements of operations with an equal amount in operating and marketing expenses. Sales taxes included in revenues and expenses for the years ended December 31, 2010, 2009 and 2008 were $164,000, $453,000 and $578,000, respectively.

Expense recognition Certain direct expenses pertaining to specific events, including prize and point fund monies and sanction fees paid to various sanctioning bodies, including NASCAR, marketing and other expenses associated with the promotion of our racing events are deferred until the event is held, at which point they are expensed.

The cost of non-event related advertising, promotion and marketing programs is expensed as incurred. Advertising expenses were $2,192,000, $2,781,000 and $3,387,000 in 2010, 2009 and 2008, respectively.

Net loss per common share Basic and diluted net loss per common share (EPS) are calculated in accordance with the provisions of ASC Topic 260, *Earnings Per Share*. Nonvested share-based payment awards that include rights to dividends or dividend equivalents, whether paid or unpaid, are considered participating securities, and the two-class method of computing EPS is applied for all periods presented.

Our restricted stock awards include the right to dividends with respect to nonvested shares. The nonvested shares of our restricted stock grants are considered participating securities and must be included in our computation of EPS. Accordingly, we have computed EPS to include the impact of outstanding nonvested shares of restricted stock in the calculation of basic EPS.

The following table sets forth the computation of basic and diluted EPS for the years ended December 31, 2010, 2009 and 2008 (in thousands, except per share amounts):

	2010	2009	2008
Net loss per common share basic:			
Net loss	$ (8,173)	$ (5,895)	$ (5,679)
Allocation to nonvested restricted stock awards		(12)	(27)
Net loss available to common stockholders	$ (8,173)	$ (5,907)	$ (5,706)
Weighted-average shares outstanding	36,095	36,021	35,940
Net loss per common share basic	$ (0.23)	$ (0.16)	$ (0.16)

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	2010	2009	2008
Net loss per common share diluted:			
Net loss	$ (8,173)	$ (5,895)	$ (5,679)
Allocation to nonvested restricted stock awards		(12)	(27)
Net loss available to common stockholders	$ (8,173)	$ (5,907)	$ (5,706)
Weighted-average shares outstanding	36,095	36,021	35,940
Dilutive stock options			
Weighted-average shares and dilutive shares outstanding	36,095	36,021	35,940
Net loss per common share diluted	$ (0.23)	$ (0.16)	$ (0.16)

For the years ended December 31, 2010, 2009 and 2008, options to purchase 293,000, 482,000 and 523,001 shares of common stock, respectively, were outstanding but not included in the computation of diluted EPS because they would have been anti-dilutive.

Accounting for stock-based compensation We recorded total stock-based compensation expense of $662,000, $495,000 and $598,000 as general and administrative expenses for the years ended December 31, 2010, 2009 and 2008, respectively. We recorded income tax benefits of $127,000, $130,000 and $243,000 for the years ended December 31, 2010, 2009 and 2008, respectively, related to our restricted stock awards.

Use of estimates The preparation of the accompanying consolidated financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions about future events. These estimates and the underlying assumptions affect the reported amounts of assets and liabilities, disclosures about contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. These estimates and assumptions are based on our best estimates and judgment. We evaluate our estimates and assumptions on an ongoing basis using historical experience and other factors, including the current economic environment, which we believe to be reasonable under the circumstances. We adjust such estimates and assumptions when facts and circumstances dictate. Illiquid credit markets, volatile equity markets and declines in consumer spending have combined to increase the uncertainty inherent in such estimates and assumptions. As future events and their effects cannot be determined with precision, actual results could differ from these estimates. Changes in those estimates resulting from continuing changes in the economic environment will be reflected in the consolidated financial statements in future periods.

Segment information We account for our operating segment in accordance with the provisions of ASC Topic 280, *Segment Reporting* which establishes guidelines for public companies in determining operating segments based on those used for internal reporting to management. Based on these guidelines, we report information under a single motorsports segment.

NOTE 3 Impairment Charges

Impairment Charges Recorded in 2010

Based upon the economic conditions that existed in the second quarter of 2010 and their impact on our current and projected operations and cash flows, and the potential impact on real estate valuations, combined with our decision to notify NASCAR that we would not seek 2011 sanctions for the two Nationwide Series and one Camping World Truck Series events at our Gateway facility, we concluded that it was necessary for us to review the carrying value of the long-lived assets at Gateway for impairment. In accordance with the provisions of ASC Topic 360, *Property, Plant and Equipment,* the recoverability of assets to be held and used was measured by a comparison of the carrying amount of the asset to the estimated undiscounted future cash flows expected to result from the use and eventual disposition of the asset. As a result of the recoverability test, we concluded that the carrying amount of our Gateway facility exceeded the undiscounted cash flows.

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Since the carrying amount of the assets exceeded the fair value, an impairment charge was recognized by the amount by which the carrying amount of the assets exceeded the fair value. Fair value of the assets for the Gateway facility was determined based on the value of owned real estate at the facility. The long-lived assets deemed to be impaired consisted of track facilities.

Based on the results of this analysis, we recorded a non-cash impairment charge in the second quarter of 2010 to write-down the carrying value of long-lived assets at our Gateway facility to fair value, as follows:

	Carrying Value of Long-Lived Assets	Fair Value of Long-Lived Assets	Non-Cash Impairment Charges
Gateway facility	$ 9,464,000	$ 1,500,000	$ 7,964,000

We closed our Memphis Motorsports Park facility in October 2009 and executed an agreement to sell it in December 2010. The real estate sale closed on January 31, 2011. After closing costs and including the proceeds from the separate sale of all personal property at the facility, our net proceeds were approximately $2,000,000. Since the carrying amount of the long-lived assets of the Memphis facility exceeded the sales price, we recognized a non-cash impairment charge of $809,000 in the fourth quarter of 2010.

Impairment Charges Recorded in 2009

We had an earlier agreement of sale relative to our Memphis Motorsports Park facility which expired in September 2009, and as a result, we concluded in the third quarter of 2009 that it was necessary for us to review the carrying value of the long-lived assets of our Memphis facility for impairment. The fair value of the assets for the Memphis facility was previously determined based upon the terms of the agreement of sale for purposes of our impairment assessment. In accordance with the provisions of ASC Topic 360, the recoverability of assets to be held and used was measured by a comparison of the carrying amount of the asset to the sum of the estimated undiscounted cash flows expected to result from the use and eventual disposition of the asset. As a result of the recoverability test, we concluded that the carrying amount of our Memphis facility exceeded the undiscounted cash flows.

Since the carrying amount of the assets exceeded the fair value, an impairment charge was recognized by the amount by which the carrying amount of the assets exceeded the fair value. Fair value of the assets for the Memphis facility was determined using a valuation methodology which gave specific consideration to the value of the land and an office building, net of demolition costs. The long-lived assets deemed to be impaired consisted of track facilities.

Based on the results of this analysis, we recorded a non-cash impairment charge in the third quarter of 2009 to write-down the carrying value of long-lived assets at our Memphis facility to fair value, as follows:

	Carrying Value of Long-Lived Assets	Fair Value of Long-Lived Assets	Non-Cash Impairment Charges
Memphis facility	$ 10,278,000	$ 2,800,000	$ 7,478,000

Impairment Charges Recorded in 2008

Based upon the current economic conditions that existed in the fourth quarter of 2008 and their impact on our current and projected operations and cash flows, and the potential impact on real estate valuations, combined with the fact that there was no change in the allocation of broadcast revenues to the NASCAR Nationwide Series for 2009, we concluded in the fourth quarter that it was necessary for us to review the carrying value of the long-lived assets of each of our Midwest facilities, consisting of Nashville Superspeedway, Memphis Motorsports Park and Gateway International Raceway, for impairment. In accordance with the provisions of ASC Topic 360, the recoverability of assets to be held and used was measured by a comparison of the carrying amount of the asset to the estimated undiscounted future cash flows expected to be generated by the asset. As a result of the recoverability test, we concluded that the carrying amount of each of our Midwest facilities exceeded the undiscounted cash flows.

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Since the carrying amount of the assets exceeded the fair value, an impairment charge was recognized by the amount by which the carrying amount of the assets exceeded the fair value. Fair value of the assets for Nashville and Gateway was determined using a valuation methodology that consisted of the cost approach, which gave specific consideration to the value of the land plus contributory value to the improvements, and the comparable sales approach. Based upon the cost approach utilized for the valuations, there was an assumption that these two facilities would continue to operate as racetracks and it was our intention to continue operating them unless it was determined that future prospects no longer justify such action. It is still our intention to operate Nashville as a racetrack; however, as discussed in NOTE 1 Business Operations we have announced the closing of the Gateway facility and during the second quarter of 2010 the Gateway facility was written down to the fair value of the owned real estate at the facility. Fair value of the assets for Memphis was determined using a valuation methodology that considered the terms of our agreement of sale and the comparable sales approach. The long-lived assets deemed to be impaired consisted of track facilities. These facilities have generated negative cash flows for several years and we expect that these negative cash flows will continue for the Nashville and Gateway facilities as we monitor industry and Nationwide series changes made by NASCAR while continuing our efforts to reduce operating expenses and increase revenues.

Based on the results of this analysis, we recorded non-cash impairment charges in 2008 to write-down the carrying value of long-lived assets at our Midwest facilities to fair value, as follows:

	Carrying Value of Long-Lived Assets	Fair Value of Long-Lived Assets	Non-Cash Impairment Charges
Nashville	$ 54,640,000	$ 51,500,000	$ 3,140,000
Memphis	12,150,000	10,000,000	2,150,000
Gateway	17,505,000	10,000,000	7,505,000
Total	$ 84,295,000	$ 71,500,000	$ 12,795,000

NOTE 4 Property and Equipment

Property and equipment consists of the following as of December 31:

	2010	2009
Land	$ 26,570,000	$ 26,570,000
Facilities	125,451,000	133,451,000
Furniture, fixtures and equipment	7,834,000	8,256,000
Construction in progress	34,000	33,000
	159,889,000	168,310,000
Less accumulated depreciation	(43,326,000)	(38,128,000)
	$ 116,563,000	$ 130,182,000

Depreciation expense was $6,177,000, $6,423,000 and $6,842,000 for the years ended December 31, 2010, 2009 and 2008, respectively.

NOTE 5 Accrued Liabilities

Accrued liabilities consist of the following as of December 31:

	2010	2009
Payroll and related items	$ 520,000	$ 523,000

Real estate taxes	1,145,000	1,044,000
Interest	415,000	434,000
Other	1,071,000	985,000
	$ 3,151,000	$ 2,986,000

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NOTE 6 Long-Term Debt

Long-term debt consists of the following as of December 31:

	2010	2009
Revolving line of credit	$ 38,200,000	$ 41,000,000
SWIDA bonds		2,974,000
	38,200,000	43,974,000
Less current portion		(1,235,000)
	$ 38,200,000	$ 42,739,000

At December 31, 2010, Dover Motorsports, Inc. and all of its wholly owned subsidiaries, as co-borrowers, were parties to a $68,000,000 secured revolving credit agreement with a bank group. The maximum borrowing limit under the facility reduces to $65,000,000 as of June 1, 2011 and $63,000,000 as of October 1, 2011 and the facility expires January 1, 2012. There was $38,200,000 outstanding under the credit facility at December 31, 2010, at a weighted average interest rate of 4.6%. The credit agreement is secured by all of our assets. It provides for seasonal funding needs, capital improvements, letter of credit requirements and other general corporate purposes. On October 28, 2010, we amended the credit agreement to revise certain financial covenants effective for the September 30, 2010 period and for the subsequent two quarterly measurement periods under the agreement, and to revise certain definitions. Interest is based, at our option, upon LIBOR plus a margin that varies between 300 and 400 basis points (400 basis points at December 31, 2010) depending on the ratio of funded debt to earnings before interest, taxes, depreciation and amortization (the leverage ratio) or upon the base rate (the greater of the prime rate, the federal funds rate plus 0.5% or the daily LIBOR rate plus 1.0%) plus a margin that varies between 200 and 300 basis points (300 basis points at December 31, 2010) depending on the leverage ratio. The terms of the credit facility contain certain covenants including minimum tangible net worth, fixed charge coverage and maximum funded debt to earnings before interest, taxes, depreciation and amortization. In addition, the credit agreement includes a material adverse change clause and prohibits the payment of dividends by us. The credit facility also provides that if we default under any other loan agreement, that would be a default under this credit facility. At December 31, 2010, we were in compliance with the terms of the credit facility.

After consideration of stand-by letters of credit outstanding, the remaining maximum borrowings available pursuant to the credit facility were $8,448,000 at December 31, 2010; however, in order to maintain compliance with the required quarterly debt covenant calculations as of December 31, 2010 only $3,844,000 could have been borrowed as of that date. We expect to be in compliance with the financial covenants, and all other covenants, for all measurement periods during the next twelve months.

In 1996, Midwest Racing, Inc. entered into an agreement (the SWIDA bonds) with Southwestern Illinois Development Authority (SWIDA) to receive the proceeds from the Taxable Sports Facility Revenue Bonds, Series 1996 (Gateway International Motorsports Corporation Project), a Municipal Bond Offering, in the aggregate principal amount of $21,500,000. SWIDA loaned all of the proceeds from the Municipal Bond Offering to Midwest Racing for the purpose of the redevelopment, construction and expansion of Gateway International Raceway (Gateway). The proceeds of the SWIDA bonds were irrevocably committed to complete construction of Gateway, to fund interest, to create a debt service reserve fund and to pay for the cost of issuance of the bonds. The repayment terms and debt service reserve requirements of the bonds issued in the Municipal Bond Offering corresponded to the terms of the SWIDA bonds. The bonds were being amortized through February 2012.

We had established certain restricted cash funds to meet debt service as required by the SWIDA bonds, which were held by the trustee (BNY Trust Company of Missouri). The SWIDA bonds were secured by a first mortgage lien on all the real property owned and a security interest in all property leased by Gateway. Also, the SWIDA bonds were unconditionally guaranteed by Midwest Racing. The SWIDA bonds bore interest at a rate of 9.2%. Interest expense related to the SWIDA bonds was $100,000, $286,000 and $382,000 for the years ended December 31, 2010, 2009 and 2008, respectively.

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On July 21, 2010, we redeemed the $1,751,000 of remaining outstanding SWIDA bonds for $1,909,000 (including a $158,000 premium to the bondholders). The redemption resulted in a loss on extinguishment of debt of $208,000 (including the premium, professional fees and the write-off of deferred financing costs) in 2010. Subsequent to redeeming the SWIDA bonds, the remaining restricted cash was returned to us by the trustee.

NOTE 7 Income Taxes

The current and deferred income tax benefit (expense) is as follows:

	Years ended December 31, 2010	2009	2008
Current:			
Federal	$	$	$
State	(815,000)	(920,000)	(1,013,000)
	(815,000)	(920,000)	(1,013,000)
Deferred:			
Federal	4,204,000	3,070,000	2,982,000
State	(76,000)	(136,000)	(438,000)
	4,128,000	2,934,000	2,544,000
Total income tax benefit	$ 3,313,000	$ 2,014,000	$ 1,531,000

A reconciliation of the effective income tax rate with the applicable statutory federal income tax rate is as follows:

	Years ended December 31, 2010	2009	2008
Federal tax at statutory rate	35.0%	35.0%	35.0%
State taxes, net of federal benefit	3.6%	5.1%	0.7%
Valuation allowance	(8.6%)	(13.7%)	(13.8%)
Other	(1.2%)	(0.9%)	(0.7%)
Effective income tax rate	28.8%	25.5%	21.2%

Deferred income tax assets and liabilities are comprised of the following as of December 31:

	2010	2009
Deferred income tax assets:		
Accruals not currently deductible for income taxes	$ 1,255,000	$ 1,310,000
Net operating loss carry-forwards	13,832,000	12,910,000
Total deferred income tax assets	15,087,000	14,220,000
Deferred income tax liabilities:		
Depreciation	(23,070,000)	(25,349,000)

	(7,983,000)	(11,129,000)
Valuation allowance	(10,412,000)	(9,439,000)
Net deferred income tax liability	$ (18,395,000)	$ (20,568,000)
Amounts recognized in the consolidated balance sheets:		
Current deferred income tax assets	$ 242,000	$ 118,000
Noncurrent deferred income tax assets	206,000	164,000
Noncurrent deferred income tax liabilities	(18,843,000)	(20,850,000)
	$ (18,395,000)	$ (20,568,000)

Deferred income taxes relate to the temporary differences between financial accounting income and taxable income and are primarily attributable to differences between the book and tax basis of property and equipment and net operating loss carry-forwards (expiring through 2030). At December 31, 2010, we have available federal and state net operating loss carryforwards of $6,263,000 and $251,596,000, respectively. Valuation allowances which fully reserve the state net operating loss carryforwards, net of federal tax benefit, increased in 2010, 2009 and 2008 by $973,000,

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$1,082,000 and $992,000, respectively. We believe that it is more likely than not that the remaining deferred tax assets will be realized based upon reversals of existing taxable temporary differences.

Interest expense on uncertain income tax positions is being recorded in accordance with the provisions of ASC Topic 740, *Income Taxes*. The unrecognized tax benefits relate to the appropriate period to depreciate certain of our assets and do not affect our effective income tax rate or our reported earnings. During the years 2010, 2009 and 2008, our liability relating to uncertain income tax positions decreased by $2,028,000, $6,361,000 and, $57,000 solely related to prior year tax positions and the expiration of the statute of limitations. We estimate that our total liability relating to uncertain income tax positions of $1,241,000 will reverse in 2011.

Interest expense on our uncertain income tax positions was $125,000, $325,000 and $610,000 in 2010, 2009 and 2008, respectively. During the third quarters of 2010 and 2009, we reversed $878,000 and $1,011,000, respectively, of previously recorded interest expense on uncertain income tax positions which are no longer subject to examination. Accrued interest on our uncertain income tax positions as of December 31, 2010 and 2009, was $122,000 and $875,000, respectively, and is included in other liabilities in the consolidated balance sheets.

We file income tax returns with the Internal Revenue Service and the states in which we conduct business. We have identified the U.S. federal and state of Delaware as our major tax jurisdictions. As of December 31, 2010, tax years after 2006 remain open to examination for federal and Delaware income tax purposes.

NOTE 8 Pension Plans

We maintain a non-contributory tax qualified defined benefit pension plan. All of our full time employees are eligible to participate in the qualified plan. Benefits provided by our qualified pension plan are based on years of service and employees remuneration over their employment period. Pension costs are funded in accordance with the provisions of the Internal Revenue Code. We also maintain a non-qualified, non-contributory defined benefit pension plan for certain employees. This excess plan provides benefits that would otherwise be provided under the qualified pension plan but for maximum benefit and compensation limits applicable under federal tax law. The cost associated with the excess plan is determined using the same actuarial methods and assumptions as those used for our qualified pension plan.

The following table sets forth the plans funded status and amounts recognized in our consolidated balance sheets as of December 31:

	2010	2009
Change in benefit obligation:		
Benefit obligation at beginning of year	$ 7,143,000	$ 6,908,000
Service cost	296,000	355,000
Interest cost	454,000	417,000
Actuarial loss (gain)	752,000	(344,000)
Curtailment	(74,000)	(70,000)
Benefits paid	(172,000)	(116,000)
Other		(7,000)
Benefit obligation at end of year	8,399,000	7,143,000
Change in plan assets:		
Fair value of plan assets at beginning of year	5,431,000	4,337,000
Actual return on plan assets	580,000	965,000
Employer contribution	202,000	245,000
Benefits paid	(172,000)	(116,000)
Fair value of plan assets at end of year	6,041,000	5,431,000
Unfunded status	$ (2,358,000)	$ (1,712,000)

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The following table presents the amounts recognized in our consolidated balance sheets as of December 31:

	2010	2009
Accrued benefit cost	$ (67,000)	$ (17,000)
Liability for pension benefits	(2,291,000)	(1,695,000)
	$ (2,358,000)	$ (1,712,000)

Amounts recognized in accumulated other comprehensive loss that have not yet been recognized as components of net periodic benefit cost at December 31 are as follows:

	2010	2009
Net actuarial loss	$ 2,563,000	$ 2,132,000
Prior service cost	55,000	81,000
	$ 2,618,000	$ 2,213,000

The accumulated benefit obligation for our pension plans was $7,845,000 and $6,591,000, respectively, as of December 31, 2010 and 2009.

The components of net periodic pension cost for the years ended December 31, 2010, 2009 and 2008 are as follows:

	2010	2009	2008
Service cost	$ 296,000	$ 355,000	$ 343,000
Interest cost	454,000	417,000	381,000
Expected return on plan assets	(463,000)	(372,000)	(507,000)
Recognized net actuarial loss	127,000	222,000	20,000
Net amortization	22,000	23,000	23,000
	$ 436,000	$ 645,000	$ 260,000

For the year ending December 31, 2011, we expect to recognize the following amounts as components of net periodic benefit cost which are included in accumulated other comprehensive loss as of December 31, 2010:

Actuarial loss	$ 152,000
Prior service cost	21,000
	$ 173,000

The principal assumptions used to determine the net periodic pension cost for the years ended December 31, 2010, 2009 and 2008, and the actuarial value of the benefit obligation at December 31, 2010 and 2009 (the measurement dates) for our pension plans are as follows:

	Net Periodic Pension Cost	Benefit Obligation

	2010	2009	2008	2010	2009
Weighted-average discount rate	6.40%	6.15%	6.50%	6.10%	6.40%
Weighted-average rate of compensation increase	4.00%	4.00%	4.00%	4.00%	4.00%
Expected long-term rate of return on plan assets	8.50%	8.50%	8.50%	n/a	n/a

For 2010, we assumed a long-term rate of return on plan assets of 8.50%. In developing the 8.50% expected long-term rate of return assumption, we considered our historical compounded return and reviewed asset class return expectations and long-term inflation assumptions.

Our investment goals are to achieve a combination of moderate growth of capital and income with moderate risk. Acceptable investment vehicles will include mutual funds, exchange-traded funds (ETFs), limited partnerships, and individual securities. Our target allocations for plan assets are 60% equities and 40% fixed income. Of the equity portion, 50% will be invested in passively managed securities using ETFs and the other 50% will be invested in actively managed investment vehicles. We address diversification by investing in mutual funds and ETFs which hold large, mid and small capitalization U.S. stocks, international (non-U.S.) equity, REITS, and real assets (consisting of inflation-linked bonds, real estate and natural resources). A sufficient percentage of investments will be readily marketable in order to be sold to fund benefit payment obligations as they become payable.

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The fair values of our pension assets as of December 31, 2010 by asset category are as follows (refer to NOTE 10 Financial Instruments for a description of Level 1, Level 2 and Level 3 categories):

Asset Category	Total	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Mutual funds/ETFs:				
Equity-large cap	$ 1,776,000	$ 1,776,000	$	$
Equity-small cap	255,000	255,000		
Equity-international	913,000	913,000		
Fixed income	2,694,000	2,694,000		
Real estate	138,000	138,000		
Money market	265,000	265,000		
Total	$ 6,041,000	$ 6,041,000	$	$

The fair values of our pension assets as of December 31, 2009 by asset category are as follows (refer to NOTE 10 Financial Instruments for a description of Level 1, Level 2 and Level 3 categories):

Asset Category	Total	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Mutual funds/ETFs:				
Equity-large cap	$ 942,000	$ 942,000	$	$
Equity-small cap	305,000	305,000		
Equity-international	1,344,000	1,344,000		
Fixed income	2,172,000	2,172,000		
Real estate	324,000	324,000		
Money market	290,000	290,000		
Other	54,000	54,000		
Total	$ 5,431,000	$ 5,431,000	$	$

We expect to contribute approximately $680,000 to our pension plans in 2011.

Benefit payments, which reflect expected future service, as appropriate, are expected to be paid as follows:

2011	$ 310,000
2012	$ 320,000
2013	$ 361,000
2014	$ 410,000
2015	$ 433,000
2016-2020	$ 2,534,000

We also maintain a defined contribution 401(k) plan that permits participation by substantially all employees.

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NOTE 9 Stockholders Equity

Changes in the components of stockholders equity are as follows (in thousands, except per share amounts):

	Common Stock	Class A Common Stock	Additional Paid-in Capital	Accumulated Deficit	Accumulated Other Comprehensive Loss
Balance at December 31, 2007	$ 1,672	$ 1,952	$ 99,849	$ (26,503)	$ (854)
Net loss				(5,679)	
Unrealized losses on available-for-sale securities, net of income tax benefit of $59					(86)
Unrealized loss on interest rate swap, net of income tax benefit of $44					(64)
Change in pension net actuarial loss and prior service cost, net of income tax benefit of $932					(1,360)
Dividends paid, $0.06 per share				(2,184)	
Proceeds from stock options exercised	4		212		
Issuance of restricted stock awards, net of forfeitures	13		(13)		
Stock-based compensation			598		
Excess tax benefit on stock awards			27		
Repurchase and retirement of common stock	(3)		(134)		
Conversion of Class A common stock to common stock	101	(101)			
Balance at December 31, 2008	1,787	1,851	100,539	(34,366)	(2,364)
Net loss				(5,895)	
Unrealized gain on interest rate swap, net of income tax expense of $147					213
Unrealized gain on available-for-sale securities, net of income tax expense of $25					36
Reclassification adjustment for loss realized on available-for-sale securities, net of income tax benefit of $37					55
Change in pension net actuarial loss and prior service cost, net of income tax expense of $509					743
Dividends paid, $0.02 per share				(733)	
Issuance of restricted stock awards, net of forfeitures	20		(20)		
Stock-based compensation			495		
Tax shortfall from stock awards			(53)		
Repurchase and retirement of common stock	(1)		(18)		
Balance at December 31, 2009	1,806	1,851	100,943	(40,994)	(1,317)
Net loss				(8,173)	
Unrealized gain on available-for-sale securities, net of income tax expense of $13					18
Change in pension net actuarial loss and prior service cost, net of income tax benefit of $166					(239)
Issuance of restricted stock awards, net of forfeitures	16		(16)		
Stock-based compensation			662		
Repurchase and retirement of common stock	(2)		(48)		
Balance at December 31, 2010	$ 1,820	$ 1,851	$ 101,541	$ (49,167)	$ (1,538)

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As of December 31, 2010 and 2009, accumulated other comprehensive loss, net of income taxes, consists of the following:

	2010	2009
Net actuarial loss and prior service cost not yet recognized in net periodic benefit cost, net of income tax benefit of $1,066,000 and $900,000, respectively	$ (1,552,000)	$ (1,313,000)
Accumulated unrealized gain (loss) on available-for-sale securities, net of income tax (expense) benefit of ($10,000) and $3,000, respectively	14,000	(4,000)
Accumulated other comprehensive loss	$ (1,538,000)	$ (1,317,000)

Holders of common stock have one vote per share and holders of Class A common stock have ten votes per share. There is no cumulative voting. Shares of Class A common stock are convertible at any time into shares of common stock on a share for share basis at the option of the holder thereof. Dividends on Class A common stock cannot exceed dividends on common stock on a per share basis. Dividends on common stock may be paid at a higher rate than dividends on Class A common stock. The terms and conditions of each issue of preferred stock are determined by our Board of Directors. No preferred shares have been issued.

We have adopted a rights plan with respect to our common stock and Class A common stock which includes the distribution of rights to holders of such stock. The rights entitle the holder, upon the occurrence of certain events, to purchase additional stock. The rights are exercisable if a person, company or group acquires 10% or more of the outstanding combined equity of common stock and Class A common stock or engages in a tender offer. We are entitled to redeem each right for $.005.

On July 29, 2009, our Board of Directors voted to suspend the declaration of regular quarterly cash dividends on all classes of our common stock. Dividends are prohibited by our credit facility.

On July 28, 2004, our Board of Directors authorized the repurchase of up to 2,000,000 shares of our outstanding common stock. The purchases may be made in the open market or in privately negotiated transactions as conditions warrant. The repurchase authorization has no expiration date, does not obligate us to acquire any specific number of shares and may be suspended at any time. No purchases of our equity securities were made pursuant to this authorization during the years ended December 31, 2010, 2009 or 2008. At December 31, 2010, we had remaining repurchase authority of 1,634,607 shares. At present we are not permitted to make such purchases under our credit facility.

During the years ended December 31, 2010, 2009 and 2008, we purchased and retired 23,814, 12,785 and 20,877 shares of our outstanding common stock at an average purchase price of $2.10, $1.51 and $6.56 per share, respectively. These purchases were made from employees in connection with the vesting of restricted stock awards under our 2004 Stock Incentive Plan and were not pursuant to the aforementioned repurchase authorization. Since the vesting of a restricted stock award is a taxable event to our employees for which income tax withholding is required, the plan allows employees to surrender to us some of the shares that would otherwise have vested in satisfaction of their tax liability. The surrender of these shares is treated by us as a purchase of the shares.

We have a 1996 stock option plan (the 1996 Plan) which provided for the grant of stock options to our officers and key employees. Under the 1996 Plan, option grants had to have an exercise price of not less than 100% of the fair market value of the underlying shares of common stock at the date of the grant. Stock options for 205,000 shares of common stock were outstanding under the 1996 Plan as of December 31, 2010 and as of January 2, 2011 all of the options expired.

In April 2004, we established the 2004 Stock Incentive Plan (the 2004 Plan) which provides for the grant of up to 1,500,000 shares of our common stock to our officers and key employees through stock options and/or awards, such as nonvested stock awards, valued in whole or in part by reference to our common stock. The nonvested stock vests an aggregate of twenty percent each year beginning on the second anniversary date of the grant. The aggregate market value of the nonvested stock at the date of issuance is being amortized on a straight-line basis over the six-year service period. No stock options have been granted under the 2004 Plan. As of December 31, 2010, there were 666,070 shares available for granting options or stock awards under the 2004 Plan.

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Stock option activity for the year ended December 31, 2010 was as follows:

	Number of Shares	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term (in yrs)	Aggregate Intrinsic Value
Outstanding at December 31, 2009	482,000	$ 5.82		
Forfeited	(49,000)	$ 5.93		
Expired	(228,000)	$ 6.81		
Outstanding at December 31, 2010	205,000	$ 4.68	.03	$
Exercisable at December 31, 2010	205,000	$ 4.68	.03	$

The total intrinsic value of stock options exercised during the year ended December 31, 2008 was $47,000 on the exercise date. No stock options were exercised during the years ended December 31, 2010 and 2009.

Nonvested stock option activity for the year ended December 31, 2010 was as follows:

	Number of Shares	Weighted Average Grant Date Fair Value
Nonvested at December 31, 2009	197	$ 5.58
Vested	(197)	$ 5.58
Nonvested at December 31, 2010		$

The total fair value of stock options vested during the years ended December 31, 2010, 2009 and 2008 was $1,000, $138,000 and $170,000, respectively. We recorded, within general and administrative expenses, compensation expense of $101,000 related to stock options for the year ended December 31, 2008. There was no compensation expense related to stock options for the years ended December 31, 2010 and 2009.

Nonvested restricted stock activity for the year ended December 31, 2010 was as follows:

	Number of Shares	Weighted Average Grant Date Fair Value
Nonvested at December 31, 2009	551,000	$ 4.04
Granted	185,000	$ 2.09
Vested	(98,000)	$ 5.68
Forfeited	(28,800)	$ 2.52
Nonvested at December 31, 2010	609,200	$ 3.25

The aggregate market value of the nonvested restricted stock at the date of issuance is being amortized on a straight-line basis over the six-year service period or the service period remaining until normal retirement age, if shorter. The total fair value of shares vested during the years ended December 31, 2010, 2009 and 2008 was $556,000, $427,000 and $310,000, respectively. The grant-date fair value of nonvested stock awards granted during the years ended December 31, 2010, 2009 and 2008 was $2.09, $1.48 and $6.60, respectively. We recorded compensation expense of $662,000, $495,000 and $497,000 related to nonvested stock awards for the years ended December 31, 2010, 2009 and 2008, respectively. As of December 31, 2010, there was $1,061,000 of total unrecognized compensation cost related to nonvested stock awards granted to employees under our stock incentive plans. That cost is expected to be recognized over a weighted-average period of 3.3 years.

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NOTE 10 Financial Instruments

Our financial instruments are classified and disclosed in one of the following three categories:

Level 1: Unadjusted quoted prices in active markets that are accessible at the measurement date for identical, unrestricted assets or liabilities;

Level 2: Quoted prices in markets that are not active, or inputs which are observable, either directly or indirectly, for substantially the full term of the asset or liability;

Level 3: Prices or valuation techniques that require inputs that are both significant to the fair value measurement and unobservable (i.e., supported by little or no market activity).

The following table summarizes the valuation of our financial instrument pricing levels as of December 31, 2010 and 2009:

	Total	Level 1	Level 2	Level 3
2010:				
Available-for-sale securities	$ 527,000	$ 527,000	$	$
2009:				
Available-for-sale securities	$ 479,000	$ 479,000	$	$

Our investments in available-for-sale securities consist of mutual funds. These investments are included in other non-current assets on our consolidated balance sheets. During the year ended December 31, 2009, we sold investments with a cost basis of $427,000 and recognized a loss on sale of $92,000. No investments were sold during the years ended December 31, 2010 or 2008.

The carrying amounts of other financial instruments reported in the balance sheet for current assets and current liabilities approximate their fair values because of the short maturity of these instruments.

At December 31, 2010 and 2009, there was $38,200,000 and $41,000,000, respectively, outstanding under our revolving credit agreement. The borrowings under our revolving credit agreement bear interest at the variable rate described in NOTE 6 Long-Term Debt and therefore we believe approximate fair value.

At December 31, 2009, our outstanding SWIDA bonds had a carrying value of $2,974,000 and an estimated fair value of $3,182,000. The fair values were determined through the use of a discounted cash flow methodology utilizing estimated interest rates that would be available to us for borrowings with similar terms.

The following table summarizes the valuation of our financial instrument pricing levels for non-financial assets that are measured at fair value on a non-recurring basis as of December 31, 2010:

	Total	Level 1	Level 2	Level 3	2010 Losses
Current assets held for sale	$ 1,875,000	$ 1,875,000	$	$	$ 809,000
Long-lived assets held and used	$ 1,500,000	$	$	$ 1,500,000	$ 7,964,000

During the fourth quarter of 2010, current assets held for sale with a carrying amount of $2,800,000 were written down to $1,875,000 fair value. This was the result of an impairment charge more fully described in NOTE 3 Impairment Charges. Fair value of these long-lived assets was determined based on the sale price agreed to by the buyer and seller.

During the second quarter of 2010, long-lived assets with a carrying amount of $9,464,000 were written down to $1,500,000 fair value. This was the result of an impairment charge more fully described in NOTE 3 Impairment Charges. Fair value of these long-lived assets was determined using a valuation methodology which gave specific consideration to the value of the owned real estate.

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The following table summarizes the valuation of our financial instrument pricing levels for non-financial assets that are measured at fair value on a non-recurring basis as of December 31, 2009:

	Total	(Level 1)	(Level 2)	(Level 3)	2009 Losses
Long-lived assets held and used	$ 2,800,000	$	$	$ 2,800,000	$ 7,478,000

During the third quarter of 2009, long-lived assets with a carrying amount of $10,278,000 were written down to $2,800,000 fair value. This was the result of an impairment charge more fully described in NOTE 3 Impairment Charges. Fair value of these long-lived assets was determined using a valuation methodology which gave specific consideration to the value of the land and an office building, net of demolition costs.

NOTE 11 Related Party Transactions

During the years ended December 31, 2010, 2009 and 2008, Dover Downs Gaming & Entertainment, Inc. (Gaming), a company related through common ownership, allocated costs of $1,977,000, $1,983,000 and $2,104,000, respectively, to us for certain administrative and operating services, including leased space. We allocated certain administrative and operating service costs of $222,000, $225,000 and $295,000, respectively, to Gaming for the years ended December 31, 2010, 2009 and 2008. The allocations were based on an analysis of each company s share of the costs. In connection with our NASCAR event weekends at Dover International Speedway, Gaming provided certain services, primarily catering, for which we were invoiced $928,000, $999,000 and $1,237,000, during the years ended December 31, 2010, 2009 and 2008, respectively. Additionally, we invoiced Gaming $353,000, $375,000 and $434,000, during 2010, 2009 and 2008, respectively, for a skybox suite, tickets and other services to the events. As of December 31, 2010 and 2009, our consolidated balance sheets included a $18,000 and $5,000 payable to Gaming, respectively, for the aforementioned items. We settled these items in January of 2011 and 2010, respectively. The net costs incurred by each company for these services are not necessarily indicative of the costs that would have been incurred if the companies had been unrelated entities and/or had otherwise independently managed these functions; however, management believes that these costs are reasonable.

Prior to the spin-off of Gaming from our company in 2002, both companies shared certain real property in Dover, Delaware. At the time of the spin-off, some of this real property was transferred to Gaming to ensure that the real property holdings of each company was aligned with its past uses and future business needs. During its harness racing season, Gaming has historically used the 5/8-mile harness racing track that is located on our property and is on the inside of our one-mile motorsports superspeedway. In order to continue this historic use, we granted a perpetual easement to the harness track to Gaming at the time of the spin-off. This perpetual easement allows Gaming to have exclusive use of the harness track during the period beginning November 1 of each year and ending April 30 of the following year, together with set up and tear down rights for the two weeks before and after such period. The easement requires that Gaming maintain the harness track but does not require the payment of any rent.

Various easements and agreements relative to access, utilities and parking have also been entered into between us and Gaming relative to our respective Dover, Delaware facilities. We pay rent to Gaming for the lease of our principal executive office space. Gaming also allows us to use its indoor grandstands in connection with our two annual motorsports weekends. This occasional grandstand use is not material to us and Gaming does not assess rent for it; Gaming may also discontinue our use at its discretion.

In April of 2002, we spun-off our gaming business which was then owned by our subsidiary, Dover Downs Gaming & Entertainment, Inc. On a tax-free basis, we made a pro rata distribution of all of the capital stock of Gaming to our stockholders. Our continuing operations subsequent to the spin-off consist solely of our motorsports activities.

In conjunction with the spin-off of Gaming by us, the two companies entered into various agreements that addressed the allocation of assets and liabilities between the two companies and that define the companies relationship after the separation. Among these are the Real Property Agreement and the Transition Support Services Agreement.

The Real Property Agreement governs certain real property transfers, leases and easements affecting our Dover, Delaware facility.

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The Transition Support Services Agreement provides for each of the two companies to provide each other with certain administrative and operational services. The party receiving the services is required to pay for them within 30 business days after receipt of an invoice at rates agreed upon by the companies. The agreement may be terminated in whole or in part 90 days after the request of the party receiving the services or 180 days after the request of the party providing the services.

Henry B. Tippie, Chairman of our Board of Directors, controls in excess of fifty percent of our voting power. Mr. Tippie s voting control emanates from his direct and indirect holdings of common stock and Class A common stock and from his status as trustee of the RMT Trust, our largest stockholder. This means that Mr. Tippie has the ability to determine the outcome of the election of directors and to determine the outcome of many significant corporate transactions, many of which only require the approval of a majority of our voting power.

Patrick J. Bagley, Kenneth K. Chalmers, Denis McGlynn, Jeffrey W. Rollins, John W. Rollins, Jr., R. Randall Rollins and Henry B. Tippie are all Directors of Dover Motorsports, Inc. and Gaming. Denis McGlynn is the President and Chief Executive Officer of both companies, Klaus M. Belohoubek is the Senior Vice President General Counsel and Secretary of both companies and Timothy R. Horne is the Senior Vice President Finance and Chief Financial Officer of both companies. Mr. Tippie controls in excess of fifty percent of the voting power of Gaming.

NOTE 12 Commitments and Contingencies

We lease equipment at our facilities with leases expiring at various dates through 2016. Total rental payments charged to operations amounted to \$309,000, \$364,000 and \$365,000 for the years ended December 31, 2010, 2009 and 2008, respectively.

The minimum lease payments due under these leases are as follows:

2011	\$ 51,000
2012	\$ 22,000
2013	\$ 15,000
2014	\$ 14,000
2015	\$ 11,000
Thereafter	\$ 1,000

In November 2010, we announced the closing of our Gateway facility. The Gateway facility is located on approximately 290 acres of land in Madison, Illinois and the racetrack is primarily on leased property. We had long-term leases for approximately 150 acres with four landlords. We also own approximately 140 acres near the Gateway facility. In February 2011, three of the four landlords agreed to terminate the land leases in exchange for 18.5 acres of owned real estate and our agreement to abandon all improvements and certain personal property (including the racetrack) on the leased land. As a result, we recorded an expense for facility exit costs of \$324,000 at December 31, 2010 primarily to record a liability for the value of the real property we conveyed to the landlords in connection with terminating the leases. As part of the lease termination agreement with one of the landlords, we provided a six month purchase option on the remaining approximately 120 acres of owned land at \$10,000 per acre, which approximates our carrying value.

In September 1999, the Sports Authority of the County of Wilson (Tennessee) issued \$25,900,000 in Variable Rate Tax Exempt Infrastructure Revenue Bonds, Series 1999, to acquire, construct and develop certain public infrastructure improvements which benefit the operation of Nashville Superspeedway, of which \$21,000,000 was outstanding at December 31, 2010. Annual principal payments range from \$700,000 in September 2011 to \$1,600,000 in 2029 and are payable solely from sales taxes and incremental property taxes generated from the facility. These bonds are direct obligations of the Sports Authority and are therefore not recorded on our consolidated balance sheet. If the sales taxes and incremental property taxes are insufficient for the payment of principal and interest on the bonds, we would become responsible for the difference. In the event we were unable to make the payments, they would be made pursuant to a \$21,352,000 irrevocable direct-pay letter of credit issued by our bank group. We are exposed to fluctuations in interest rates for these bonds. A significant increase in interest rates could result in us being responsible for debt service payments not covered by the sales and incremental property taxes generated from the facility.

We believe that the sales taxes and incremental property taxes generated from the facility will continue to satisfy the necessary debt service requirements of the bonds through the maturity date in 2029. As of December 31, 2010 and 2009, $1,200,000 and $915,000, respectively, was available in the sales and incremental property tax fund maintained by the Sports Authority to pay the remaining principal and interest due under the bonds. During 2010, we paid $1,038,000 into the sales and incremental property tax fund and $753,000 was deducted from the fund for principal and interest payments. If the debt service is not satisfied from the sales and incremental property taxes generated from the facility, a portion of the bonds would become our liability. If we fail to maintain the letter of credit that secures the bonds or we allow an uncured event of default to exist under our reimbursement agreement relative to the letter of credit, the bonds would be immediately redeemable.

We have employment, severance and noncompete agreements with certain of our officers and directors under which certain change of control, severance and noncompete payments and benefits might become payable in the event of a change in our control, defined to include a tender offer or the closing of a merger or similar corporate transactions. In the event of such a change in control and the subsequent termination of employment of all employees covered under these agreements, we estimate that the maximum contingent liability would range from $7,400,000 to $8,700,000 depending on the tax treatment of the payments.

To the extent that any of the potential payments or benefits due under the agreements constitute an excess parachute payment under the Internal Revenue Code and result in the imposition of an excise tax, each agreement requires that we pay the amount of such excise tax plus any additional amounts necessary to place the officer or director in the same after-tax position as he would have been had no excise tax been imposed. We estimate that the tax gross ups that could be paid under the agreements in the event the agreements were triggered due to a change of control could be between $1,100,000 and $2,400,000 and these amounts have been included in the maximum contingent liability disclosed above. This maximum tax gross up figure assumes that none of the payments made after the hypothetical change in control would be characterized as reasonable compensation for services rendered. Each agreement with an executive officer provides that fifty percent of the monthly amount paid during the term is paid in consideration of the executive officer s non-compete covenants. The exclusion of these amounts would reduce the calculated amount of excess parachute payments subject to tax. We are unable to conclude whether the Internal Revenue Service would characterize all or some of these non-compete payments as reasonable compensation for services rendered.

We are also a party to ordinary routine litigation incidental to our business. Management does not believe that the resolution of any of these matters is likely to have a material adverse effect on our results of operations, financial position or cash flows.

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NOTE 13 Quarterly Results (unaudited)

	March 31	June 30[(a)]	September 30[(b)]	December 31[(c)]
Year Ended December 31, 2010				
Revenues	$ 167,000	$ 32,510,000	$ 28,511,000	$ 1,772,000
Operating (loss) earnings	$ (6,462,000)	$ (906,000)	$ 6,250,000	$ (7,706,000)
Net (loss) earnings	$ (4,599,000)	$ (1,685,000)	$ 3,416,000	$ (5,305,000)
Net (loss) earnings per common share:				
Basic	$ (0.13)	$ (0.05)	$ 0.09	$ (0.15)
Diluted	$ (0.13)	$ (0.05)	$ 0.09	$ (0.15)
Year Ended December 31, 2009				
Revenues	$ 85,000	$ 35,618,000	$ 31,144,000	$ 4,031,000
Operating (loss) earnings	$ (6,737,000)	$ 7,755,000	$ (161,000)	$ (6,564,000)
Net (loss) earnings	$ (4,688,000)	$ 3,888,000	$ (524,000)	$ (4,571,000)
Net (loss) earnings per common share:				
Basic	$ (0.13)	$ 0.11	$ (0.01)	$ (0.13)
Diluted	$ (0.13)	$ 0.11	$ (0.01)	$ (0.13)

(a) During the second quarter of 2010, we recorded non-cash impairment charges of $7,964,000 ($5,176,000 after income taxes) related to our long-lived assets. See NOTE 3 Impairment Charges.

(b) During the third quarter of 2009, we recorded non-cash impairment charges of $7,478,000 ($4,861,000 after income taxes) related to our long-lived assets. See NOTE 3 Impairment Charges.

(c) During the fourth quarter of 2010, we recorded non-cash impairment charges of $809,000 ($526,000 after income taxes) related to our long-lived assets. See NOTE 3 Impairment Charges.

During the fourth quarter of 2010, we announced the closing of our Gateway facility. We have long-term leases for land at the facility and upon closing the facility we recognized expense of $589,000 ($383,000 after income taxes) to record a liability for the estimated fair value of Gateway s future net lease obligations.

In November 2010, we announced the closing of our Gateway facility. In February 2011, we terminated a majority of our leases in exchange for 18.5 acres of owned real estate and certain personal property. As a result, we recorded an expense for facility exit costs of $324,000 at December 31, 2010 primarily to record a liability for the value of the real property we conveyed to the landlords in connection with terminating the leases.

We promoted an NHRA event at our Memphis facility during the fourth quarter of 2009. This event was not promoted in 2010.

Per share data amounts for the quarters have each been calculated separately. Accordingly, quarterly amounts may not add to the annual amounts due to differences in the average common shares outstanding during each period.

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Property, plant and equipment, net	6,270	6,078
Deferred debits and other assets		
Regulatory assets	1,419	1,378
Investments	22	22
Investments in affiliates	8	8
Receivable from affiliates	410	360
Prepaid pension asset	368	373
Other	38	40

Total deferred debits and other assets	2,265	2,181
Total assets	$9,745	$9,353

See the Combined Notes to Consolidated Financial Statements

PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS

(In millions)	September 30, 2013 (Unaudited)	December 31, 2012
LIABILITIES AND SHAREHOLDERS EQUITY		
Current liabilities		
Short-term notes payable accounts receivable agreement	$	$ 210
Long-term debt due within one year	300	300
Accounts payable	249	244
Accrued expenses	91	82
Payables to affiliates	51	76
Customer deposits	49	51
Regulatory liabilities	111	169
Other	28	26
Total current liabilities	879	1,158
Long-term debt	2,196	1,647
Long-term debt to financing trusts	184	184
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	2,440	2,331
Asset retirement obligations	29	29
Non-pension postretirement benefits obligations	301	284
Regulatory liabilities	592	538
Other	105	113
Total deferred credits and other liabilities	3,467	3,295
Total liabilities	6,726	6,284
Commitments and contingencies		
Preferred securities		87
Shareholder's equity		
Common stock	2,388	2,388
Retained earnings	630	593
Accumulated other comprehensive income, net	1	1
Total shareholder's equity	3,019	2,982
Total liabilities and shareholders' equity	$ 9,745	$ 9,353

See the Combined Notes to Consolidated Financial Statements

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PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENT OF CHANGES IN SHAREHOLDERS EQUITY

(Unaudited)

(In millions)	Common Stock	Retained Earnings	Accumulated Other Comprehensive Income, net	Total Shareholders Equity
Balance, December 31, 2012	$ 2,388	$ 593	$ 1	$ 2,982
Net income		292		292
Common stock dividends		(248)		(248)
Preferred security dividends		(1)		(1)
Redemption of preferred securities		(6)		(6)
Balance, September 30, 2013	$ 2,388	$ 630	$ 1	$ 3,019

See the Combined Notes to Consolidated Financial Statements

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BALTIMORE GAS AND ELECTRIC COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME

(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions)	**2013**	**2012**	**2013**	**2012**
Operating revenues				
Operating revenues	$ 735	$ 716	$ 2,261	$ 2,023
Operating revenues from affiliates	2	4	10	9
Total operating revenues	737	720	2,271	2,032
Operating expenses				
Purchased power and fuel	202	253	703	747
Purchased power from affiliate	144	120	356	296
Operating and maintenance	125	172	391	460
Operating and maintenance from affiliates	21	29	59	97
Depreciation and amortization	78	68	252	218
Taxes other than income	53	48	162	143
Total operating expenses	623	690	1,923	1,961
Operating income	114	30	348	71
Other income and (deductions)				
Interest expense	(29)	(35)	(94)	(110)
Other, net	4	5	13	18
Total other income and (deductions)	(25)	(30)	(81)	(92)
Income (loss) before income taxes	89		267	(21)
Income taxes	36		107	(7)
Net income (loss)	53		160	(14)
Preference stock dividends	3	4	10	10
Net income (loss) attributable to common shareholder	50	(4)	150	(24)
Comprehensive income (loss)	$ 53	$	$ 160	$ (14)

See the Combined Notes to Consolidated Financial Statements

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BALTIMORE GAS AND ELECTRIC COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

	Nine Months Ended September 30,	
(In millions)	**2013**	**2012**
Cash flows from operating activities		
Net (loss) income	$ 160	$ (14)
Adjustments to reconcile net income (loss) to net cash flows provided by operating activities:		
Depreciation, amortization and accretion	252	218
Deferred income taxes and amortization of investment tax credits	105	101
Other non-cash operating activities	105	148
Changes in assets and liabilities:		
Accounts receivable	(28)	
Receivables from and payables to affiliates, net	(12)	2
Inventories	(15)	21
Accounts payable, accrued expenses and other current liabilities	(5)	4
Income taxes	6	(50)
Pension and non-pension postretirement benefit contributions	(16)	(13)
Other assets and liabilities	(119)	(77)
Net cash flows provided by operating activities	433	340
Cash flows from investing activities		
Capital expenditures	(391)	(419)
Change in restricted cash	(20)	(19)
Other investing activities	2	8
Net cash flows used in investing activities	(409)	(430)
Cash flows from financing activities		
Changes in short-term debt	40	
Issuance of long-term debt	300	250
Repayment of long-term debt	(433)	(141)
Dividends paid on preference stock	(10)	(10)
Contributions from parent		66
Other financing activities	(3)	(3)
Net cash flows (used in) provided by financing activities	(106)	162
Increase (decrease) in cash and cash equivalents	(82)	72
Cash and cash equivalents at beginning of period	89	49
Cash and cash equivalents at end of period	$ 7	$ 121

See the Combined Notes to Consolidated Financial Statements

BALTIMORE GAS AND ELECTRIC COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS

(In millions)	**September 30, 2013 (Unaudited)**	**December 31, 2012**
ASSETS		
Current assets		
Cash and cash equivalents	$ 7	$ 89
Restricted cash and cash equivalents of variable interest entity	50	30
Accounts receivable, net		
Customer	404	409
Other	132	111
Income taxes receivable		3
Inventories, net		
Gas held in storage	61	51
Materials and supplies	36	31
Deferred income taxes	5	1
Prepaid utility taxes	76	57
Regulatory assets	184	190
Other	7	8
Total current assets	962	980
Property, plant and equipment, net	5,713	5,498
Deferred debits and other assets		
Regulatory assets	509	522
Investments	5	5
Investments in affiliates	8	8
Prepaid pension asset	434	467
Other	26	26
Total deferred debits and other assets	982	1,028
Total assets	$ 7,657	$ 7,506

See the Combined Notes to Consolidated Financial Statements

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BALTIMORE GAS AND ELECTRIC COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS

(In millions)	September 30, 2013 (Unaudited)	December 31, 2012
LIABILITIES AND SHAREHOLDERS EQUITY		
Current liabilities		
Short-term borrowings	$ 40	$
Long-term debt due within one year		400
Long-term debt of variable interest entity due within one year	69	67
Accounts payable	184	195
Accrued expenses	127	106
Deferred income taxes	9	
Payables to affiliates	54	65
Customer deposits	72	71
Regulatory liabilities	31	29
Other	58	47
Total current liabilities	644	980
Long-term debt	1,746	1,446
Long-term debt to financing trust	258	258
Long-term debt of variable interest entity	230	265
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	1,759	1,658
Asset retirement obligations	7	8
Non-pension postretirement benefits obligations	221	229
Regulatory liabilities	218	214
Other	66	90
Total deferred credits and other liabilities	2,271	2,199
Total liabilities	5,149	5,148
Commitments and contingencies		
Shareholders equity		
Common stock	1,360	1,360
Retained earnings	958	808
Total shareholder's equity	2,318	2,168
Preference stock not subject to mandatory redemption	190	190
Total equity	2,508	2,358
Total liabilities and shareholders equity	$ 7,657	$ 7,506

See the Combined Notes to Consolidated Financial Statements

BALTIMORE GAS AND ELECTRIC COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENT OF CHANGES IN SHAREHOLDERS EQUITY

(Unaudited)

(In millions)	Common Stock	Retained Earnings	Total Shareholders Equity	Preference stock not subject to mandatory redemption	Total Equity
Balance, December 31, 2012	$ 1,360	$ 808	$ 2,168	$ 190	$ 2,358
Net income		160	160		160
Preference stock dividends		(10)	(10)		(10)
Balance, September 30, 2013	$ 1,360	$ 958	$ 2,318	$ 190	$ 2,508

See the Combined Notes to Consolidated Financial Statements

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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

1. Basis of Presentation (Exelon, Generation, ComEd, PECO and BGE)

Exelon is a utility services holding company engaged through its principal subsidiaries in the energy generation and energy distribution businesses. Prior to March 12, 2012, Exelon s principal, wholly owned 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 (the Merger Agreement). As a result of the merger transaction, Generation now includes the former Constellation generation and customer supply operations. BGE, formerly Constellation s regulated utility subsidiary, is now a subsidiary of Exelon. Refer to Note 4 Merger and Acquisitions for further information regarding the merger transaction.

The energy generation business includes:

Generation: Physical delivery and marketing of owned and contracted electric generation capacity and provision of renewable and other energy-related products and services, and natural gas exploration and production activities. Generation has six reportable segments consisting of the Mid-Atlantic, Midwest, New England, New York, ERCOT and Other regions.

The energy delivery businesses include:

ComEd: Purchase and regulated retail sale of electricity and the provision of distribution and transmission services in northern Illinois, including the City of Chicago.

PECO: Purchase and regulated retail sale of electricity and the provision of distribution and transmission services in southeastern Pennsylvania, including the City of Philadelphia, and the purchase and regulated retail sale of natural gas and the provision of distribution services in the Pennsylvania counties surrounding the City of Philadelphia.

BGE: Purchase and regulated retail sale of electricity and the provision of distribution and transmission services in central Maryland, including the City of Baltimore, and the purchase and regulated retail sale of natural gas and the provision of distribution services in central Maryland, including the City of Baltimore.

For financial statement purposes, beginning on March 12, 2012, disclosures that solely relate to Constellation or BGE activities now also apply to Exelon, unless otherwise noted. When appropriate, Exelon, Generation, ComEd, PECO and BGE are named specifically for their related activities and disclosures.

Exelon did not apply push-down accounting to BGE. As a result, BGE continues to maintain its reporting requirements as an SEC registrant. The information disclosed for BGE represents the activity of the standalone entity for the three and nine months ended September 30, 2013 and 2012 and the financial position as of September 30, 2013 and December 31, 2012. However, for Exelon s financial reporting, Exelon is reporting BGE activity for the three and nine months ended September 30, 2013 and from March 12, 2012 through September 30, 2012 and the financial position as of September 30, 2013 and December 31, 2012.

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

For the nine months ended September 30, 2013, BGE recorded a $2 million correcting adjustment to decrease amortization expense related to regulatory assets that were originally recorded during 2012 and a $4 million correcting adjustment to decrease operating and maintenance expense for an overstatement of BGE s life insurance obligation related to post-employment benefits in prior years. Exelon and BGE have concluded that these correcting adjustments are not material to their respective results of operations or cash flows for the nine

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

months ended September 30, 2013 or any prior period presented. Exelon and BGE do not expect these correcting adjustments to have a material impact on their respective results of operations or cash flows for the year ended December 31, 2013.

The accompanying consolidated financial statements as of September 30, 2013 and 2012 and for the three and nine months then ended are unaudited but, in the opinion of the management of each Registrant include all adjustments that are considered necessary for a fair statement of the Registrants respective financial statements in accordance with GAAP. All adjustments are of a normal, recurring nature, except as otherwise disclosed. The December 31, 2012 Consolidated Balance Sheets were obtained from audited financial statements. Certain prior year amounts in Exelon s and BGE s Consolidated Statements of Cash Flows, Exelon s, Generation's and BGE s Consolidated Statements of Operations and Comprehensive Income and in Exelon s, Generation's, ComEd s, and BGE s Consolidated Balance Sheets have been reclassified between line items for comparative purposes. BGE recorded an adjustment to its Consolidated Statement of Cash Flows for the nine months ended September 30, 2012 to reflect the change in operating cash flows and capital expenditures related to amounts not paid of approximately $17 million. The reclassifications did not materially affect any of the Registrants net income or cash flows from operating or investing activities. Financial results for interim periods are not necessarily indicative of results that may be expected for any other interim period or for fiscal year ended December 31, 2013. These Combined Notes to Consolidated Financial Statements have been prepared pursuant to the rules and regulations of the SEC for Quarterly Reports on Form 10-Q. Certain information and note disclosures normally included in financial statements prepared in accordance with GAAP have been condensed or omitted pursuant to such rules and regulations. These notes should be read in conjunction with the Notes to Combined Consolidated Financial Statements of all Registrants included in ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA of their respective 2012 Form 10-K Reports.

2. New Accounting Pronouncements (Exelon, Generation, ComEd, PECO and BGE)

The following recently issued accounting standards were adopted by or are effective for the Registrants during 2013.

Presentation of Items Reclassified out of Accumulated Other Comprehensive Income

In February 2013, the FASB issued authoritative guidance requiring entities to present either in the notes or parenthetically on the face of the financial statements, reclassifications from each component of accumulated other comprehensive income and the affected income statement line items. Entities only need to disclose the affected income statement line item for components reclassified to net income in their entirety; otherwise, a cross-reference to the related note should be provided. This guidance was effective for the Registrants for periods beginning after December 15, 2012 and was required to be applied prospectively. As this guidance provides only disclosure requirements, the adoption of this standard did not impact the Registrants results of operations, cash flows or financial positions. See Note 16 Changes in Accumulated Other Comprehensive Income for the new disclosures.

Disclosures About Offsetting Assets and Liabilities

In December 2011, the FASB issued (and amended in January 2013), authoritative guidance requiring entities to disclose both gross and net information about recognized derivative instruments, including bifurcated embedded derivatives, repurchase and reverse repurchase agreements, and securities borrowing or lending transactions that are offset on the balance sheet or subject to an enforceable master netting arrangement or similar agreement, irrespective of whether they are offset on the balance sheet. This guidance was effective for the Registrants for periods beginning on or after January 1, 2013 and is required to be applied retrospectively. This guidance is primarily applicable to certain derivative transactions for Exelon and Generation. As this guidance provides only disclosure requirements, the adoption of this standard did not impact the Registrants results of operations, cash flows or financial positions. See Note 10 Derivative Financial Instruments for the new disclosures.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Inclusion of the Fed Funds Effective Swap Rate as a Benchmark Interest Rate for Hedge Accounting Purposes

In July 2013, the FASB issued authoritative guidance permitting entities to designate the Fed Funds Effective Swap Rate as a U.S. benchmark interest rate for hedge accounting purposes. Prior to the issuance of this guidance, only interest rates on direct treasury obligations of the U.S. government and the LIBOR swap rate were considered benchmark interest rates in the U.S. This guidance was effective immediately and can be applied prospectively for qualifying new or redesignated hedging relationships entered into on or after July 17, 2013. Currently, the Registrants do not use the Fed Funds Effective Swap Rate as a benchmark interest rate, but may in the future.

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

Presentation of Unrecognized Tax Benefits When Net Operating Loss Carryforwards, Similar Tax Losses or Tax Credit Carryforwards Exist

In July 2013, the FASB issued authoritative guidance requiring entities to present unrecognized tax benefits as a reduction to deferred tax assets for losses or other tax carryforwards that would be available to offset the uncertain tax positions at the reporting date. Currently, the Registrants present their unrecognized tax benefits as liabilities on a gross basis unless an unrecognized tax benefit is directly associated with a tax position taken in a tax year that results in the recognition of a net operating loss or other tax carryforward for that year. This guidance is effective for the Registrants for periods beginning after December 15, 2013 and is required to be applied prospectively, with retroactive application permitted. The Registrants are currently assessing the impacts this guidance may have on their financial positions and cash flows. The adoption of this standard will not impact the Registrants results of operations.

3. Variable Interest Entities (Exelon, Generation, ComEd, PECO and BGE)

Under the applicable authoritative guidance, a VIE is a legal entity that possesses any of the following characteristics: an insufficient amount of equity at risk to finance its activities, equity owners who do not have the power to direct the significant activities of the entity (or have voting rights that are disproportionate to their ownership interest), or equity owners who do not have the obligation to absorb expected losses or the right to receive the expected residual returns of the entity. Companies are required to consolidate a VIE if they are its primary beneficiary, which is the enterprise that has the power to direct the activities that most significantly impact the entity s economic performance.

As of September 30, 2013 and December 31, 2012, the Registrants consolidated four and five VIEs or VIE groups, respectively, for which the Registrants were the primary beneficiary and the Registrants had significant interests in seven and nine other VIEs for which the Registrants do not have the power to direct the entities activities, respectively, and, accordingly, were not the primary beneficiary.

Consolidated Variable Interest Entities

Exelon, Generation and BGE s consolidated VIEs consist of:

BondCo, a special purpose bankruptcy remote limited liability company formed by BGE to acquire, hold, and issue and service bonds secured by rate stabilization property;

a retail gas group formed to enter into a collateralized gas supply agreement with a third-party gas supplier;

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

a group of solar project limited liability companies formed to build, own and operate solar power facilities, and,

several wind project companies designed to develop, construct and operate wind generation facilities.

As of September 30, 2013, ComEd and PECO do not have any consolidated VIEs.

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. In the case of BondCo, BGE is required to remit all payments it receives from all residential customers through non-bypassable, rate stabilization charges to BondCo. During the three and nine months ended September 30, 2013, BGE remitted $24 million and $63 million, respectively, to BondCo. During the three and nine months ended September 30, 2012, BGE remitted $27 million and $62 million, respectively, to BondCo.

Except for providing capital funding to the solar entities for ongoing construction of the solar power facilities and a $75 million parental guarantee to the third-party gas supplier in support of the retail gas group, during the nine months ended September 30, 2013 and year ended December 31, 2012:

Exelon, Generation and BGE did not provide any additional financial support to the VIEs;

Exelon, Generation and BGE did not have any 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.

The carrying amounts and classification of the consolidated VIEs assets and liabilities included in Exelon s, Generation s, and BGE s consolidated financial statements at September 30, 2013 and December 31, 2012 are as follows:

	September 30, 2013			December 31, 2012		
	Exelon(a)(b)	**Generation(b)**	**BGE**	**Exelon(a)(b)(c)**	**Generation(b)(c)**	**BGE**
Current assets	$ 391	$ 330	$ 50	$ 550	$ 519	$ 30
Noncurrent assets	1,900	1,877	3	1,802	1,762	
Total assets	$ 2,291	$ 2,207	$ 53	$ 2,352	$ 2,281	$ 30
Current liabilities	$ 453	$ 366	$ 77	$ 685	$ 613	$ 71
Noncurrent liabilities	859	608	230	837	532	265
Total liabilities	$ 1,312	$ 974	$ 307	$ 1,522	$ 1,145	$ 336

(a) Includes certain purchase accounting adjustments not pushed down to the BGE standalone entity.
(b) Includes total liabilities of $53 million as of September 30, 2013 and total assets of $116 million and total liabilities of $62 million as of December 31, 2012 related to deferred and accrued taxes that have been recorded and are not restricted for use by three of the consolidated VIEs.
(c) Includes total assets of $146 million and total liabilities of $42 million as of December 31, 2012 related to a retail power supply company that is no longer a consolidated VIE as of September 30, 2013.

In August 2013, Generation executed an agreement to terminate its energy supply contract with a retail power supply company that was previously a consolidated VIE. Generation did not have an ownership interest in the entity, but was the primary beneficiary through the energy supply contract. As a result of the termination, Generation no longer has a variable interest in the retail power supply company and ceased consolidation of the

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

entity during the third quarter of 2013. Upon deconsolidation, there was no gain or loss recognized. The assets, liabilities, and non-controlling interest were removed from Generation s balance sheet and the change in non-controlling interest is also reflected on the Statement of Changes in Shareholders Equity.

Unconsolidated Variable Interest Entities

Exelon s and Generation s variable interests in unconsolidated VIEs generally include three transaction types: (1) equity method investments, (2) energy purchase and sale contracts, and (3) fuel purchase commitments. For the equity method investments, the carrying amount of the investments is reflected on their Consolidated Balance Sheets in Investments in affiliates. For the energy purchase and sale contracts and the fuel purchase commitments (commercial agreements), the carrying amount of assets and liabilities in Exelon s and Generation s Consolidated Balance Sheets that relate to their involvement with the VIEs are predominately related to working capital accounts and generally represent the amounts owed by, or owed to, Exelon and Generation for the deliveries associated with the current billing cycles under the commercial agreements. Further, Exelon and Generation have not provided material debt or equity support, liquidity arrangements or performance guarantees associated with these commercial agreements.

The Registrants unconsolidated VIEs consist of:

Energy purchase and sale agreements with VIEs for which Generation has concluded that consolidation is not required.

ZionSolutions, LLC asset sale agreement with EnergySolutions, Inc. and certain subsidiaries in which Generation has a variable interest but has concluded that consolidation is not required.

Fuel purchase commitments where Generation has a variable interest, but the variable interest is not significant and Generation is not the primary beneficiary, thus consolidation is not required.

ComEd s, PECO s and BGE s retail operations frequently include the purchase of electricity and RECs through procurement contracts of varying durations. None of ComEd, PECO or BGE considers itself the primary beneficiary of any VIEs as a result of these commercial arrangements.

Investment in energy development projects for which Generation has concluded that consolidation is not required.

As of September 30, 2013 and December 31, 2012, Exelon and Generation had significant unconsolidated variable interests in seven and nine, respectively, VIEs for which they were not the primary beneficiary; including certain equity method investments and certain commercial agreements. The change in the number of unconsolidated variable interests is driven by the completion of certain obligations which cause the entities to no longer be unconsolidated variable interests. The following tables present summary information about the significant unconsolidated VIE entities:

September 30, 2013	**Commercial Agreement VIEs**	**Equity Method Investment VIEs**	**Total**
Total assets(a)	$ 115	$ 366	$ 481
Total liabilities(a)	3	126	129

Registrants ownership interest(a)		97	97
Other ownership interests(a)	112	143	255
Registrants maximum exposure to loss:			
Carrying amount of equity method investments		78	78
Contract intangible asset	9		9
Debt and payment guarantees		5	5
Net assets pledged for Zion Station decommissioning(b)	43		43

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

December 31, 2012	**Commercial Agreement VIEs**	**Equity Method Investment VIEs**	**Total**
Total assets(a)	$ 386	$ 354	$ 740
Total liabilities(a)	219	114	333
Registrants ownership interest(a)		97	97
Other ownership interests(a)	167	143	310
Registrants maximum exposure to loss:			
Letters of credit	5		5
Carrying amount of equity method investments		77	77
Contract intangible asset	8		8
Debt and payment guarantees		5	5
Net assets pledged for Zion Station decommissioning(b)	50		50

(a) These items represent amounts on the unconsolidated VIE balance sheets, not on Exelon s or Generation s Consolidated Balance Sheets. These items are included to provide information regarding the relative size of the unconsolidated VIEs.

(b) These items represent amounts on Exelon s and Generation s Consolidated Balance Sheets related to the asset sale agreement with ZionSolutions, LLC. The net assets pledged for Zion Station decommissioning includes gross pledged assets of $486 million and $614 million as of September 30, 2013 and December 31, 2012, respectively; offset by payables to ZionSolutions LLC of $443 million and $564 million as of September 30, 2013 and December 31, 2012, 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 assess the risk of a loss equal to their maximum exposure to be remote and, accordingly Exelon and Generation have not recognized a liability associated with any portion of the maximum exposure to loss. In addition, there are no agreements with, or commitments by, third parties that would affect the fair value or risk of their variable interests in these variable interest entities.

4. Merger and Acquisitions

Merger with Constellation (Exelon, Generation, ComEd, PECO and BGE)

Description of Transaction

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

Regulatory Matters

In February 2012, the MDPSC issued an Order approving the Exelon and Constellation merger. As part of the MDPSC Order, Exelon agreed to provide a package of benefits to BGE customers, the City of Baltimore and the State of Maryland, resulting in an estimated direct investment in the State of Maryland of approximately $1 billion.

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

The direct investment estimate includes $95 million to $120 million relating to the construction of a headquarters building in Baltimore for Generation s competitive energy businesses. On March 20, 2013, Generation signed a 20 year lease agreement that is contingent upon the developer obtaining all required approvals, permits and financing for the construction of the building. Once required approvals are received and financing conditions are met, construction will commence and the building is expected to be ready for occupancy in approximately 2 years after building construction commences. The direct investment estimate also includes $625 million for Exelon s and Generation s commitment to develop or assist in development of 285 300 MWs of new generation in Maryland, expected to be completed over a period of 10 years. Such costs, which are expected to be primarily capital in nature, will be recognized as incurred. As of September 30, 2013, amounts reflected in the Exelon and Generation consolidated financial statements for these expenditure commitments were immaterial. On July 26, 2013, Generation executed an engineering procurement and construction contract to expand its Perryman, Maryland site with 120MW of new natural gas-fired generation to satisfy certain of these commitments and achievement of commercial operation is expected in 2015. See Note 18 Commitments and Contingencies for additional information.

The MDPSC Order contemplates various options for complying with the new generation development commitments, including building or acquiring generating assets, making subsidy or compliance payments, or in circumstances in which the generation build is delayed, making liquidated damages payments. Exelon and Generation expect that the majority of these commitments will be satisfied by building or acquiring generating assets and, therefore, will be primarily capital in nature and recognized as incurred. If in the future Exelon determines that it is probable that it will make subsidy, compliance or liquidated damages payments related to the new generation development commitments, Exelon will record a liability at that time. As of September 30, 2013, it is reasonably possible that Exelon will be required to make subsidy or liquidated damages payments of approximately $40 million rather than build one of the generation projects contemplated by the commitments, given that the generation build is dependent upon the passage of legislation and other conditions that Exelon does not control.

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. In 2012, Exelon and Generation recorded a pre-tax loss of $272 million 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.

Accounting for the Merger Transaction

The fair value of Constellation s non-regulated business assets acquired and liabilities assumed was determined based on significant estimates and assumptions that are judgmental in nature, including projected future cash flows (including timing); discount rates reflecting risk inherent in the future cash flows; and future market prices. There were also judgments made to determine the expected useful lives assigned to each class of assets acquired and duration of liabilities assumed.

The financial statements of BGE do not include fair value adjustments for assets or liabilities subject to rate-setting provisions for BGE. BGE is subject to the rate-setting authority of FERC and the MDPSC and is accounted for pursuant to the accounting guidance for regulated operations. The rate-setting and cost recovery provisions currently in place for BGE provide revenue derived from costs including a return on investment of assets and liabilities included in rate base. Except for debt, fuel supply contracts and regulatory assets not earning a return, the fair values of BGE's tangible and intangible assets and liabilities subject to these rate-setting

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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 Basis of Presentation for additional information on BGE s push-down accounting treatment. Also see Note 5 Regulatory Matters for additional information on BGE s regulatory assets.

The preliminary valuations performed in the first quarter of 2012 were updated in the second, third and fourth quarters of 2012, with the most significant adjustments to the preliminary valuation amounts having been made to the fair values assigned to the acquired power supply and fuel contracts, unregulated property, plant and equipment and investments in affiliates. There were no significant adjustments to the purchase price allocation in the first quarter of 2013 and the purchase price allocation was final as of March 31, 2013.

The final purchase price allocation of the Merger of Exelon with Constellation and Exelon s contribution of certain subsidiaries of Constellation to Generation was as follows:

Purchase Price Allocation, excluding amortization	**Exelon**	**Generation**
Current assets	$ 4,936	$ 3,638
Property, plant and equipment	9,342	4,054
Unamortized energy contracts	3,218	3,218
Other intangibles, trade name and retail relationships	457	457
Investment in affiliates	1,942	1,942
Pension and OPEB regulatory asset	740	
Other assets	2,265	1,266
Total assets	22,900	14,575
Current liabilities	3,408	2,804
Unamortized energy contracts	1,722	1,512
Long-term debt, including current maturities	5,632	2,972
Noncontrolling interest	90	90
Deferred credits and other liabilities and preferred securities	4,683	1,933
Total liabilities, preferred securities and noncontrolling interest	15,535	9,311
Total purchase price	$ 7,365	$ 5,264

Intangible Assets Recorded

For the power supply and fuel contracts acquired from Constellation, the difference between the contract price and the market price at the date of the merger was recognized as either an intangible asset or liability based on whether the contracts were in or out-of-the-money. The fair value amounts are amortized over the life of the contract in relation to the present value of the underlying cash flows as of the merger date. Amortization expense and income are recorded through purchased power and fuel expense or operating revenues. Exelon and Generation present separately in their Consolidated Balance Sheets the unamortized energy contract assets and liabilities for these contracts. Exelon s and Generation s amortization expense for the three and nine months ended September 30, 2013 amounted to $40 million and $372 million, respectively. Exelon s and Generation s amortization expense for the three months ended September 30, 2012 and for the period March 12, 2012 to September 30, 2012 amounted to $261 million and $794 million, respectively. In addition, Exelon Corporate has established a regulatory asset and an unamortized energy contract liability related to BGE s power supply and fuel contracts. The power supply and fuel contracts regulatory asset amortization was $19 million and $57 million for the three and nine months ended September 30, 2013, respectively, and $36 million and $80 million

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

for the three months ended September 30, 2012 and for the period March 12, 2012 to September 30, 2012, respectively. An equally offsetting amortization of the unamortized energy contract liability has been recorded at Exelon Corporate in the Consolidated Statement of Operations.

Exelon s and Generation s amortization expense for the fair value of the Constellation trade name intangible asset for the three and nine months ended September 30, 2013 amounted to $8 million and $20 million, respectively. Exelon s and Generation s straight line amortization expense for the fair value of the Constellation trade name intangible asset for the three months ended September 30, 2012 and the period March 12, 2012 to September 30, 2012 amounted to $6 million and $14 million, respectively. The trade name intangible asset is included in deferred debits and other assets within Exelon s and Generation s Consolidated Balance Sheets.

The intangible assets for the fair value of the retail relationships are amortized as amortization expense on a straight line basis over the useful life of the underlying assets. Exelon s and Generation s straight line amortization expense for the three and nine months ended September 30, 2013 amounted to $8 million and $17 million, respectively. Exelon s and Generation s straight line amortization expense for the three months ended September 30, 2012 and the period March 12, 2012 to September 30, 2012 amounted to $2 million and $9 million, respectively. The retail relationships intangible assets are included in deferred debits and other assets within Exelon s and Generation s Consolidated Balance Sheets.

Exelon s intangible assets and liabilities acquired through the merger with Constellation included in its Consolidated Balance Sheets, along with the future estimated amortization, were as follows as of September 30, 2013:

					Estimated amortization expense					
Description	**Weighted Average Amortization (Years)(b)**	**Gross**	**Accumulated Amortization**	**Net**	**Remainder of 2013**	**2014**	**2015**	**2016**	**2017**	**2018 and Beyond**
Unamortized energy contracts, net(a)	1.5	$ 1,499	$ (1,299)	$ 200	$ 79	$ 75	$ 18	$ (31)	$ (21)	$ 80
Trade name	10.0	243	(40)	203	6	24	24	24	24	101
Retail relationships	12.4	214	(31)	183	5	19	18	18	18	105
Total, net		$ 1,956	$ (1,370)	$ 586	$ 90	$ 118	$ 60	$ 11	$ 21	$ 286

(a) Includes the fair value of BGE's power and gas supply contracts of $32 million for which an offsetting regulatory asset was also recorded.
(b) Weighted average amortization period was calculated as of the date of acquisition.

Impact of Merger

It is impracticable to determine the overall financial statement impact for the Constellation subsidiaries contributed down to Generation following the Upstream Merger for the three and nine months ended September 30, 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 included operating revenues of $720 million and no net income during the three months ended September 30, 2012, and operating revenues of $1,388 million and net loss of $49 million during the nine months ended September 30, 2012.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

During the three months ended September 30, 2013, Exelon, Generation, ComEd, PECO and BGE incurred merger and integration-related costs of $43 million, $32 million, $5 million, $3 million and $2 million, respectively. During the nine months ended September 30, 2013, Exelon, Generation, ComEd, PECO and BGE incurred merger and integration-related costs of $106 million, $75 million, $14 million, $8 million and $5 million, respectively. Of these amounts, Exelon, ComEd and BGE deferred $15 million, $10 million and $5 million, respectively, as a regulatory asset as of September 30, 2013. Additionally, Exelon and BGE established a regulatory asset of $6 million as of September 30, 2013 for previously incurred 2012 merger and integration-related costs.

During the three months ended September 30, 2012, Exelon, Generation, ComEd, PECO and BGE incurred merger and integration-related costs of $95 million, $79 million, $8 million, $3 million and $1 million, respectively. During the nine months ended September 30, 2012, Exelon, Generation, ComEd, PECO and BGE incurred merger and integration-related costs of $729 million, $283 million, $34 million, $13 million and $172 million, respectively. Of these amounts, Exelon, ComEd and BGE deferred $49 million, $30 million and $19 million, respectively, as a regulatory asset as of September 30, 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 the three and nine months ended September 30, 2012. See Note 18 Commitments and Contingencies for additional information.

Severance Costs

The Registrants have an ongoing severance plan under which, in general, the longer an employee worked prior to termination the greater the amount of severance benefits. The Registrants record a liability and expense or regulatory asset for severance once terminations are probable of occurrence and the related severance benefits can be reasonably estimated. For severance benefits that are incremental to its ongoing severance plan (one-time termination benefits), the Registrants measure the obligation and record the expense at fair value at the communication date if there are no future service requirements, or, if future service is required to receive the termination benefit, ratably over the required service period.

Upon closing the merger with Constellation, Exelon recorded a severance accrual for the anticipated employee position reductions as a result of the post-merger integration. The majority of these positions are corporate and Generation support positions. Since then, Exelon has identified specific employees to be severed pursuant to the merger-related staffing and selection process as well as employees that were previously identified for severance but have since accepted another position within Exelon and are no longer receiving a severance benefit. Exelon adjusts its accrual each quarter to reflect its best estimate of remaining severance costs. In addition, certain employees identified during the staffing and selection process also receive pension and other postretirement benefits that are deemed contractual termination benefits, which the Registrants recorded during the second quarter of 2012.

The amount of severance expense associated with the post-merger integration recognized for the three months ended September 30, 2013 for Exelon and Generation were $3 million and $3 million, respectively. For Generation, $2 million represents amounts billed by BSC through intercompany allocations. The amount of severance expense associated with the post-merger integration recognized for the nine months ended September 30, 2013 for Exelon and Generation were $6 million and $6 million, respectively. For Generation, $5 million represents amounts billed by BSC through intercompany allocations. There was no severance expense associated with post-merger integration recognized for the three and nine months ended September 30, 2013 for ComEd, PECO and BGE. Estimated costs to be incurred after September 30, 2013 are not material.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

For the three and nine months ended September 30, 2012, the Registrants recorded the following severance benefits costs associated with the identified job reductions within operating and maintenance expense in their Consolidated Statements of Operations, except for ComEd and BGE:

Three Months Ended September 30, 2012 **Severance Benefits(a)**	**Exelon**	**Generation**	**ComEd(b)**	**PECO**	**BGE(c)**
Severance charges	$ 8	$ 4	$ 1	$ 1	$ 1
Stock compensation	3	2	1		
Total severance benefits	$ 11	$ 6	$ 2	$ 1	$ 1

Nine Months Ended September 30, 2012 **Severance Benefits(a)**	**Exelon**	**Generation**	**ComEd(b)**	**PECO**	**BGE(c)**
Severance charges	$ 117	$ 68	$ 16	$ 8	$ 18
Stock compensation	6	4	1		
Other charges(d)	7	4	1		1
Total severance benefits	$ 130	$ 76	$ 18	$ 8	$ 19

(a) The amounts above include $0 million and $40 million at Generation, $2 million and $16 million at ComEd, $1 million and $8 million at PECO, and $1 million and $7 million at BGE, for amounts billed by BSC through intercompany allocations for the three and nine months ended September 30, 2012, respectively.
(b) ComEd established regulatory assets of $2 million and $18 million for severance benefits costs for the three and nine months ended September 30, 2012, respectively. The majority of these costs are expected to be recovered over a five-year period.
(c) BGE established regulatory assets of $1 million and $19 million for severance benefits costs for the three and nine months ended September 30, 2012, respectively. The majority of these costs are being recovered over a five-year period beginning in March 2013.
(d) Primarily includes life insurance, employer payroll taxes, educational assistance and outplacement services.

Amounts included in the table below represent the severance liability recorded by Exelon, Generation, ComEd, PECO and BGE for employees of those Registrants and exclude amounts billed through intercompany allocations:

Nine Months Ended September 30, 2013 **Severance liability**	**Exelon**	**Generation**	**ComEd**	**PECO**	**BGE**
Balance at December 31, 2012	$ 111	$ 33	$ 1	$	$ 11
Severance charges(a)	5	1			
Stock compensation	1				
Payments	(52)	(20)			(4)
Balance at September 30, 2013	$ 65	$ 14	$ 1	$	$ 7

(a) Includes salary continuance and health and welfare severance benefits. Amounts represent ongoing severance plan benefits.

Cash payments under the plan began in the second quarter of 2012. Substantially all cash payments under the plan are expected to be made by the end of 2016.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

The Registrants provide severance and health and welfare benefits under Exelon s ongoing severance benefit plans to terminated employees in the normal course of business, which are not directly related to the merger with Constellation. These benefits are accrued for when the benefits are considered probable and can be reasonably estimated.

For the three and nine months ended September 30, 2013, the Registrants recorded the following severance costs associated with these ongoing severance benefits within operating and maintenance expense in their Consolidated Statements of Operations:

Severance Benefits(a)	Exelon	Generation	ComEd	PECO	BGE
Severance charges three months	$ 12	$ 11	$ 1	$	$
Severance charges nine months	14	12	2		

(a) The amounts above for Generation include $1 million for amounts billed by BSC through intercompany allocations for the three and nine months ended September 30, 2013.

For the three and nine months ended September 30, 2012, the Registrants recorded the following severance costs associated with these ongoing severance benefits within operating and maintenance expense in their Consolidated Statements of Operations:

Severance Benefits(a)	Exelon	Generation	ComEd	PECO	BGE
Severance charges three months	$ 5	$ 3	$ 1	$	$ 1
Severance charges nine months	11	8	1		2

(a) The amounts above for Generation include $1 million for amounts billed by BSC through intercompany allocations for the three and nine months ended September 30, 2012.

The severance liability balances associated with these ongoing severance benefits as of September 30, 2013 and December 31, 2012 are not material.

Pro-forma Impact of the Merger

The following unaudited pro forma financial information reflects the consolidated results of operations of Exelon and Generation as if the merger with Constellation had taken place on January 1, 2011. The unaudited pro forma information was calculated after applying Exelon s and Generation s accounting policies and adjusting Constellation s results to reflect purchase accounting adjustments.

The unaudited pro forma financial information has been presented for illustrative purposes only and is not necessarily indicative of results of operations that would have been achieved had the merger events taken place on the dates indicated, or the future consolidated results of operations of the combined company.

	Three Months Ended September 30, 2012	
	Generation	Exelon
Total Revenues	$ 4,293	$ 6,841
Net income attributable to Exelon	282	492
Basic Earnings Per Share	n.a.	$ 0.58
Diluted Earnings Per Share	n.a.	0.57

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	Nine Months Ended September 30, 2012	
	Generation	**Exelon**
Total Revenues	$ 12,753	$ 20,084
Net income attributable to Exelon	805	1,439
Basic Earnings Per Share	n.a.	$ 1.79
Diluted Earnings Per Share	n.a.	1.79

5. Regulatory Matters (Exelon, Generation, ComEd, PECO and BGE)

Regulatory and Legislative Proceedings (Exelon, Generation, ComEd, PECO and BGE)

Except for the matters noted below, the disclosures set forth in Note 3 Regulatory Matters of the Exelon 2012 Form 10-K appropriately represent, in all material respects, the current status of regulatory and legislative proceedings of the Registrants. The following is an update to that discussion.

Illinois Regulatory Matters

Energy Infrastructure Modernization Act (Exelon and ComEd). Since 2011, ComEd s distribution rates are established through a performance-based rate formula, pursuant to EIMA. EIMA also provides a structure for substantial capital investment by utilities over a ten-year period to modernize Illinois electric utility infrastructure. Participating utilities are required to file an annual update to the performance-based formula rate tariff on or before May 1, with resulting rates effective in January of the following year. This 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 September 30, 2013, and December 31, 2012, ComEd had recorded a net regulatory asset associated with the distribution formula rate of $404 million and $209 million, respectively.

During March 2013, the Illinois House and Senate each passed Senate Bill 9 with supermajority votes to clarify the intent of EIMA on three major issues: the use of year-end rather than average rate base and capital structure in the annual reconciliation, the use of ComEd s weighted average cost of capital interest rate to apply to the annual reconciliation and an allowed return on ComEd s pension asset. On May 22, 2013, the Illinois General Assembly overrode the Governor s May 5, 2013 veto of Senate Bill 9, which resulted in the legislation becoming effective immediately. ComEd projects the override of Senate Bill 9 will result in increased operating revenues of approximately $25 million for 2013 and $65 million in 2014. Also, ComEd projects that Senate Bill 9 will accelerate capital expenditures by approximately $40 million and $45 million in 2013 and 2014, respectively.

On May 30, 2013, ComEd updated the distribution formula rate structure to reflect the impacts of Senate Bill 9. On June 5, 2013, the ICC approved the May 30 filing implementing ComEd s formula rate structure change as well as the resulting reduction to the current revenue requirement in effect of $14 million, which was reflected in customer rates effective July 1, 2013.

On May 31, 2013, ComEd updated its April 29, 2013, distribution formula rate filing to reflect the impacts of Senate Bill 9. The May 31, 2013 filing establishes the revenue requirement used to set the rates that will take effect in January 2014 after the ICC s review and approval, which is due by December 25, 2013. The revenue requirement requested is based on 2012 actual costs and projected 2013 capital additions as well as an annual reconciliation of the revenue requirement in effect in 2012 to the actual costs incurred for that year. ComEd s current request is a total increase to the revenue requirement including the impacts of Senate Bill 9, of $353 million, reflecting an increase of $162 million for the initial revenue requirement for 2013 and an increase of $191 million for the annual reconciliation for 2012. The revenue requirement provides for a weighted average debt and equity return on distribution rate base of 6.94% inclusive of an allowed return on common equity of 8.72%, reflecting the average rate on 30-year treasury notes plus 580 basis points.

On September 4, 2013, the Attorney General filed a complaint (the Complaint) with the ICC to change the formula rate structure approved by the ICC on June 5, 2013. In the Complaint, the Attorney General proposed the following three changes to the formula: 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 October 2, 2013, the ICC opened an investigation (the Investigation) in which it undertook to review the three issues raised in the Complaint and determine if ComEd s current formula rate structure complies with Senate Bill 9. On October 31, 2013, the Attorney General asked to voluntarily withdraw the Complaint. ComEd is unable to predict the outcome of the ICC s Investigation; however, if the ICC were to rule against ComEd on these three issues, the impact could be material to ComEd s results of operations, cash flows, and financial position. ComEd expects the Investigation to be resolved in the fourth quarter of 2013.

On April 1, 2013, ComEd filed annual progress reports on both its AMI Implementation Plan and Infrastructure Investment Plan as required by EIMA. On April 9, 2013, the ICC initiated an investigation to review ComEd s progress on its AMI Implementation Plan. The ICC did not initiate an investigation on ComEd s Infrastructure Investment Plan. On June 5, 2013, the ICC issued an interim order approving ComEd s accelerated AMI deployment plan consistent with the provisions of Senate Bill 9. In September 2013, ComEd began smart grid deployment with 60,000 meters to be installed by the end of 2013. On June 26, 2013, the ICC issued a final order on the overall progress of ComEd s AMI Implementation Plan with no significant findings.

Appeal of 2007 Illinois Electric Distribution Rate Case (Exelon and ComEd). The ICC issued an order in ComEd s 2007 electric distribution rate case (2007 Rate Case) approving a $274 million increase in ComEd s annual delivery services revenue requirement, which became effective in September 2008. In the order, the ICC authorized a 10.3% rate of return on common equity. ComEd and several other parties filed appeals of the rate order with the Illinois Appellate Court (Court). The Court issued a decision on September 30, 2010, ruling against ComEd on the treatment of post-test year accumulated depreciation and the recovery of system modernization costs via a rider (Rider SMP).

The Court held the ICC abused its discretion in not reducing ComEd s rate base to account for an additional 18 months of accumulated depreciation while including post-test year pro forma plant additions through that period (the same position ComEd took in its 2010 electric distribution rate case (2010 Rate Case) discussed below). 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 Rate Case became effective. In August 2011, ComEd filed testimony in the remand proceeding that no refunds should be required. The ICC subsequently initiated a proceeding on remand. On February 23, 2012, the ICC issued an order on remand in the proceeding 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.

On October 1, 2013, the Court ruled against ComEd on the accumulated depreciation issue. The Court affirmed that ComEd owes a refund to customers of $37 million. As of September 30, 2013, and December 31, 2012, ComEd was fully reserved for this liability. ComEd will not seek rehearing or appeal on this matter and is working with the ICC on the process and timing for a refund to customers.

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

2010 Illinois Electric Distribution Rate Case (Exelon and ComEd). On June 30, 2010, ComEd filed its 2010 Rate Case requesting ICC approval for an increase of $396 million to its annual delivery services revenue requirement. This request was subsequently reduced to $343 million to account for changes in tax law, corrections, acceptance of limited adjustments proposed by certain parties and the amounts expected to be recovered in the AMI pilot program tariff. The request to increase the annual revenue requirement was to allow ComEd to recover the costs of substantial investments made since its last rate filing in 2007. The requested increase also reflected increased costs, most notably pension and OPEB, since ComEd s rates were last determined. The original requested rate of return on common equity was 11.5%. In addition, ComEd requested future recovery of certain amounts that were previously recorded as expense that would allow ComEd to recognize a one-time benefit of up to $40 million (pre-tax). The requested increase also included $22 million for increased uncollectible accounts expense, which would increase the threshold for determining over/under recoveries under ComEd s uncollectible accounts tariff.

On May 24, 2011, the ICC issued an order, which became effective on June 1, 2011. The order approved a $143 million increase to ComEd s annual delivery services revenue requirement and a 10.5% rate of return on common equity. As expected, the ICC followed the Court s ruling in ComEd s 2007 Rate Case on the post-test year accumulated depreciation issue. The order allowed ComEd to establish or reestablish a net amount of approximately $40 million of previously expensed plant balances or new regulatory assets, which was reflected as a reduction in operating and maintenance expense and income tax expense in 2011. The order also affirmed the current regulatory asset for severance costs, which was challenged by an intervener in the 2010 Rate Case. The order was appealed to the Court by several parties on a number of issues. On May 16, 2013, the Court dismissed as moot the appeals of the ICC s order in the 2010 Rate Case as ComEd now recovers distribution costs under EIMA through a pre-established formula rate tariff. See Note 3 of Exelon s 2012 Form 10-K for further details on ComEd s 2007 Rate Case and 2010 Rate Case.

Illinois Procurement Proceedings (Exelon and ComEd). ComEd is permitted to recover its electricity procurement costs from retail customers without mark-up. The IPA s 2013 procurement plan, approved by the ICC, provides for curtailment of the existing long-term contracts for renewable energy and RECs in response to the increased number of ComEd s customers purchasing their energy from competitive electric generation suppliers on their own or through municipal aggregation. In March 2013, ICC staff and the IPA approved ComEd s updated load forecast. Purchases under the existing long-term contracts for energy and the associated RECs were reduced on a pro-rata basis under the terms of those contracts for the June 2013 May 2014 period to keep the purchases under the statutory rate impact cap. The curtailment s impact on ComEd s financial position and cash flows was immaterial.

On December 19, 2012, the ICC issued an order directing ComEd and Ameren (the Utilities) to enter into 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 proposed term of the sourcing agreement is 20 years. The project was approved by the DOE on February 4, 2013. The sourcing agreement was approved by the ICC on June 26, 2013 in a separate proceeding, with the ICC ordering ComEd to execute the sourcing agreement no later than 60 days after the date of the order. The sourcing agreement stipulates that the Utilities will pay FutureGen s contract prices, which are set annually based on a formula rate construct. The contract prices are based on the difference between the costs of the facility and the revenues FutureGen receives from selling capacity and energy from the unit into the MISO or other markets, as well as any other revenue FutureGen receives from the operation of the facility. The order also directs the Utilities to recover (or pass along) these costs from the Utilities distribution system customers, regardless of whether they purchase electricity from the utility or from competitive electric generation suppliers. On January 22, 2013, ComEd filed an application for rehearing, requesting the ICC reconsider its December 2012 order requiring the Utilities to procure the entire output of the FutureGen facility. On January 29, 2013, the ICC denied ComEd s rehearing request. ComEd filed an appeal with the Illinois Appellate Court on February 22, 2013, questioning the legality of requiring ComEd to procure power for retail customers purchasing electricity from competitive electric generation suppliers.

On August 22, 2013, the Utilities executed the contract with FutureGen in accordance with the ICC order. However, in the event the order is reversed as a result of the appeal, ComEd s obligations under the contract should be suspended. Depending on the ultimate outcome of the appeals, the eventual market conditions and the cost of the facility, the sourcing agreement could have a material adverse impact on Exelon s and ComEd s cash flows and financial positions.

See Note 18 Commitments and Contingencies for additional information on ComEd s energy commitments and ICC s proceedings related to storm waivers.

Pennsylvania Regulatory Matters

Pennsylvania Procurement Proceedings (Exelon and PECO). PECO s first PAPUC approved DSP Program, under which PECO was providing default electric service, had a 29-month-term that ended May 31, 2013. On October 12, 2012, the PAPUC issued its Opinion and Order approving PECO s second DSP Program, which was filed with the PAPUC in January 2012. The program, which has a 24-month term from June 1, 2013 through May 31, 2015, complies with electric generation procurement guidelines set forth in Act 129.

In the second DSP Program, PECO is procuring electric supply for its default electric customers through five competitive procurements. The load for the residential and small and medium commercial classes is served through competitively procured fixed price, full requirements contracts of two years or less. For the large commercial and industrial class load, PECO has competitively procured contracts for full requirements default electric generation with the price for energy in each contract set to be the hourly price of the spot market during the term of delivery. In December 2012 and February 2013, PECO entered into contracts with PAPUC-approved bidders, including Generation, for its residential and small and medium commercial classes that began in June 2013. In September 2013, PECO entered into contracts with PAPUC-approved bidders, including Generation, for its residential and small and medium commercial classes that will begin in December 2013. Charges incurred for electric supply procured through contracts with Generation are included in purchased power from affiliates on PECO s Statement of Operations and Comprehensive Income.

In addition, the second DSP Program includes a number of retail market enhancements recommended by the PAPUC in its previously issued Retail Markets Intermediate Work Plan Order. PECO was also directed to allow its low-income Customer Assistance Program (CAP) customers to purchase their generation supply from EGSs beginning April 2014. On May 1, 2013, PECO filed its CAP Shopping Plan with the PAPUC.

Smart Meter and Smart Grid Investments (Exelon and PECO). Pursuant to Act 129 and the follow-on Implementation Order of 2009, in April 2010, the PAPUC approved PECO s Smart Meter Procurement and Installation Plan (SMPIP), under which PECO will install more than 1.6 million smart meters and an AMI communication network by 2020. The first phase of PECO s SMPIP, which was completed on June 19, 2013, included the installation of an AMI communications network and the deployment of 600,000 smart meters to communicate with that network. On May 31, 2013, PECO and interested parties filed a Joint Petition for Settlement of the universal deployment plan with the PAPUC which was approved without modification on August 15, 2013. The Joint Petition for Settlement supports all material aspects of PECO s universal deployment plan, including cost recovery, excluding certain amounts discussed below. Universal deployment is the second phase of PECO s SMPIP, under which PECO will deploy the remainder of the 1.6 million smart meters on an accelerated basis by the end of 2014. In total, PECO currently expects to spend up to $595 million, excluding the

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

cost of the original meters (as further described below), on its smart meter infrastructure and approximately $120 million on smart grid investments through 2014 of which $200 million will be funded by SGIG as discussed below. As of September 30, 2013, PECO has spent $364 million and $111 million on smart meter and smart grid infrastructure, respectively, not including the DOE reimbursements received to date.

Pursuant to the ARRA of 2009, PECO and the DOE entered into a Financial Assistance Agreement to extend PECO $200 million in non-taxable SGIG funds of which $140 million relates to smart meter deployment and $60 million relates to smart grid infrastructure. As part of the agreement, the DOE has a conditional ownership interest in qualifying Federally-funded project property and equipment, which is subordinate to PECO s existing mortgage. The SGIG funds are being used to offset the total impact to ratepayers of the smart meter deployment required by Act 129. As of September 30, 2013, PECO has received $181 million of the $200 million in reimbursements. PECO s outstanding receivable from the DOE for reimbursable costs was $6 million as of September 30, 2013, which has been recorded in Other accounts receivable, net on Exelon s and PECO s Consolidated Balance Sheets.

On August 15, 2012, PECO suspended installation of smart meters for new customers based on a limited number of incidents involving overheating meters. Following its own internal investigation and additional scientific analysis and testing by independent experts completed after September 30, 2012, PECO announced its decision to resume meter deployment work on October 9, 2012. PECO has replaced the previously installed meters with an alternative vendor s meters. PECO is moving forward with the alternative meters during universal deployment and continues to evaluate meters from several vendors and may use more than one meter vendor during universal deployment.

Following PECO s decision, as of October 9, 2012, PECO will no longer use the original smart meters. For the meters that will no longer be used, the accounting guidance requires that any difference between the carrying value and net realizable value be recognized in the current period s earnings, before considering potential regulatory recovery. The cost of the original meters, including installation and removal costs, owned by PECO was approximately $19 million, net of approximately $16 million of reimbursements from the DOE. PECO is seeking full recovery of all incurred costs related to the original deployment of meters. For amounts not recovered from the vendor, PECO will seek regulatory rate recovery in a future filing with the PAPUC. PECO did not seek recovery of original meter costs in the January 2013 universal deployment filing, as resolution with the vendor is still pending. PECO requested and received approval from the DOE that the original meters continue to be allowable costs and that any settlement with the vendor will not be considered project income. In addition, PECO remains eligible for the full $200 million in SGIG funds. In the May 31, 2013 Joint Petition for Settlement of the universal deployment plan, the parties agreed to defer any potential challenges to cost recovery of the original meters as discussed above.

As of September 30, 2013, PECO believes the amounts incurred for the original meters and related installation and removal costs are probable of recovery based on applicable case law and past precedent on reasonably and prudently incurred costs. As a result, a regulatory asset of $17 million, representing the cost of the original meters, net of accumulated depreciation and DOE reimbursements, was recorded on Exelon s and PECO s Consolidated Balance Sheets. On August 15, 2013, PECO entered into an agreement with the vendor, which is anticipated to be part of a larger agreement, and under which PECO transferred the original uninstalled meters to the vendor and will receive approximately $12 million in return, of which $2 million has been received as of September 30, 2013. As a result, during the third quarter of 2013, the $17 million regulatory asset was reduced to $5 million. The agreement does not fully resolve the claim against the vendor for the original meter costs and PECO continues to seek full recovery from the vendor of all incurred costs related to the original deployment of meters. If PECO later determines that the remaining regulatory asset is no longer probable of recovery, PECO would be required to recognize a charge in earnings in the period in which that determination was made.

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

Energy Efficiency Programs (Exelon and PECO). PECO s PAPUC-approved Phase I EE&C Plan had a four-year term that began on June 1, 2009 and concluded on May 31, 2013. The Phase I Plan set forth how PECO would meet the required reduction targets established by Act 129 s EE&C provisions, which included a 3% reduction in electric consumption in PECO s service territory and a 4.5% reduction in PECO s annual system peak demand in the 100 hours of highest demand by May 31, 2013. The peak demand period ended on September 30, 2012 and PECO communicated its compliance with the reduction targets in a preliminary report with the PAPUC on March 1, 2013. The final compliance report is due to the PAPUC by 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 seeks approval to allow PECO to recover $12 million in equipment, installation and information technology costs for its Residential DLC program with the amounts collected for the Phase I Plan. As the Phase I Plan was implemented at a cost less than originally budgeted, PECO proposed to recover these expenses from its Phase I Energy Efficiency Program Charge over-collection consistent with PAPUC guidance to recover all Phase I costs through Phase I funding. The PAPUC approved PECO s Petition on May 9, 2013. A regulatory liability was established for the DLC program costs that will be amortized as a credit to the income statement to offset the related depreciation expense during the same period.

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

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 cost 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.

Investigation of Pennsylvania Retail Electricity Market (Exelon and PECO). On July 28, 2011, the PAPUC issued an order outlining the next steps in its investigation into the status of competition in Pennsylvania s retail electric market. The PAPUC found that the existing default service model presents substantial impediments to the development of a vibrant retail market in Pennsylvania and directed its Office of Competitive Markets Oversight to evaluate potential intermediate and long-term structural changes to the default service model. On March 1, 2012, the PAPUC issued the final order describing more detailed recommendations to be implemented prior to the expiration of the electric distribution company s current default service plan and providing guidelines for electric distribution companies for development of their next default service plan. On October 12, 2012, the PAPUC approved PECO s second DSP Program, which includes several new programs to continue PECO's support of retail market competition in Pennsylvania in accordance with the order issued by the PAPUC on December 15, 2011. Further, the PAPUC issued a final order on February 14, 2013, outlining its proposed end-state for default service, which included default service pricing for residential and small commercial customers based on three month full requirements contracts, full requirement contracts using hourly spot market pricing for large commercial and industrial default service customers, and the inclusion of CAP customers in the customer choice programs.

Pennsylvania Act 11 of 2012 (Exelon and PECO). On February 13, 2012, Act 11 was signed into law by the Governor. Act 11 seeks to clarify the PAPUC's authority to approve alternative ratemaking mechanisms,

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

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 that rates are in effect. The PAPUC s 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 PAPUC prior to implementing a DSIC. On May 9, 2013, the PAPUC approved PECO s LTIIP for its Gas Operations, which was filed on February 8, 2013.

Maryland Regulatory Matters

Smart Meter and Smart Grid Investments (Exelon and BGE). In August 2010, the MDPSC approved a comprehensive smart grid initiative for BGE that includes the planned installation of 2 million residential and commercial electric and gas smart meters at an expected total cost of $480 million. The MDPSC s approval ordered BGE to defer the associated incremental costs, depreciation and amortization, and an appropriate return, in a regulatory asset until such time as a cost-effective advanced metering system is implemented. As of September 30, 2013 and December 31, 2012, BGE recorded a regulatory asset of $52 million and $31 million, respectively, representing incremental costs, depreciation and amortization, and a debt return on fixed assets related to its AMI program. Additionally, the MDPSC has determined that the cost recovery for the non-AMI meters that BGE retires will be considered in a future depreciation proceeding. The MDPSC continues to evaluate the impacts of a customer opt-out feature in BGE s Smart Grid program. In March 2013, BGE filed a description of the overall additional costs associated with allowing customers to retain their current meter, and for radio frequency (RF)-Free and RF-Minimizing options related to the installation of their smart meters as well as a proposed cost recovery mechanism. The MDPSC held a hearing in August 2013 to consider the filings made by BGE and other Maryland electric utilities. The ultimate resolution related to this feature could affect BGE s ability to demonstrate cost-effectiveness of the advanced metering system. Overall, BGE continues to believe the recovery of smart grid initiative costs in future rates is probable as BGE expects to be able to demonstrate that the program benefits exceed costs. Pursuant to the ARRA of 2009, BGE is a recipient of $200 million in federal funding from the DOE for its smart grid and other related initiatives, which substantially reduces the total cost of these initiatives to BGE s ratepayers. The project to install the smart meters began in late April 2012.

As of September 30, 2013, BGE had received $176 million in reimbursements from the DOE. As of September 30, 2013, BGE s outstanding receivable from the DOE for reimbursable costs was $23 million, which has been recorded in Other accounts receivable, net on Exelon s and BGE s Consolidated Balance Sheets.

New Electric Generation (Exelon, Generation and BGE). On April 12, 2012, the MDPSC issued an order directing BGE and two other Maryland utilities to enter into a contract for differences (CfD) with CPV Maryland, LLC (CPV), under which CPV will construct an approximately 700 MW natural gas-fired combined-cycle generation plant in Waldorf, Maryland, that CPV projected will be in commercial operation by June 1, 2015. The initial term of the proposed contract is 20 years. The CfD mandates that BGE and the other utilities pay (or receive) the difference between CPV s contract prices and the revenues CPV receives for capacity and energy from clearing the unit in the PJM capacity market. The MDPSC s Order requires the three Maryland utilities to enter into a CfD in amounts proportionate to their relative SOS load.

On April 16, 2013, the MDPSC issued an order that required BGE to execute a specific form of contract with CPV, and the parties executed the contract as of June 6, 2013. As of September 30, 2013, there is no impact on Exelon s and BGE s results of operations, cash flows and financial positions. Furthermore, the agreement does not become effective until the resolution of certain items, including all current litigation.

On April 27, 2012, a civil complaint was filed in the U.S. District Court for the District of Maryland by certain unaffiliated parties that challenges the actions taken by the MDPSC on Federal law grounds. On October 24, 2013, the U.S. District Court issued a judgment order finding that the MDPSC s Order directing BGE and the two other Maryland utilities to enter into a CfD, which assures that CPV receives a guaranteed fixed price regardless of the price set by the federally regulated wholesale market, violates the Supremacy Clause of the United States Constitution.

On 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.

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.

2012 Maryland Electric and Gas Distribution Rate Case (Exelon and BGE). On July 27, 2012, BGE filed an application for increases to its electric and gas base rates with the MDPSC. On February 22, 2013, the MDPSC issued an order in BGE s 2012 electric and natural gas distribution rate case for increases in annual distribution service revenue of $81 million and $32 million, respectively. The electric distribution rate increase was set using an allowed return on equity of 9.75% and the gas distribution rate increase was set using an allowed return on equity of 9.60%. The approved electric and natural gas distribution rates became effective for services rendered on or after February 23, 2013. As part of the rate order, the MDPSC approved both recovery of and return on merger integration costs incurred during the test year, including severance. As a result, the order affirmed the treatment of $20 million of severance-related costs that BGE had recorded as a regulatory asset in 2012, consistent with prior MDPSC decisions. Additionally, BGE established a new regulatory asset of $8 million related to non-severance merger integration costs, which includes $6 million of costs incurred during 2012. Current MDPSC treatment of these merger integration regulatory assets is to provide recovery over a five year period.

MDPSC Derecho Storm Order (Exelon and BGE). Following the June 2012 Derecho storm which hit the mid-Atlantic region interrupting electrical service to a significant portion of the State of Maryland, the MDPSC issued an order on February 27, 2013 requiring BGE and other Maryland utilities to file several comprehensive reports with short-term and long-term plans to improve reliability and grid resiliency that were due at various times before August 30, 2013.

BGE s May 17, 2013 distribution rate case included a short-term plan to improve reliability as well as a proposal for a surcharge to recover incremental capital expenditures and operating costs associated with the short-term plan. On September 3, 2013, BGE filed a comprehensive long term assessment examining potential

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alternatives for improving the resiliency of the electric grid and a staffing analysis reviewing historical staffing levels as well as forecasting staffing levels necessary under various storm scenarios. BGE currently cannot predict the outcome of these proceedings, which may result in increased capital expenditures and operating costs.

The Maryland Strategic Infrastructure Development and Enhancement Program (Exelon and BGE). In February 2013, the Maryland General Assembly passed legislation intended to accelerate gas infrastructure replacements in Maryland by establishing a mechanism for gas companies to promptly recover reasonable and prudent costs of eligible infrastructure replacement projects separate from base rate proceedings. On May 2, 2013, the Governor of Maryland signed the legislation into law; which took effect June 1, 2013. Under the new law, following a proceeding before the MDPSC and with the MDPSC s approval of the eligible infrastructure replacement projects along with a corresponding surcharge, BGE could begin charging gas customers a monthly surcharge for infrastructure costs incurred after June 1, 2013. The legislation includes caps on the monthly surcharges to residential and non-residential customers, and would require an annual true-up of the surcharge revenues against actual expenditures. Investment levels in excess of the cap would be recoverable in a subsequent gas base rate proceeding at which time all costs for the infrastructure replacement projects would be rolled into gas distribution rates. Irrespective of the cap, BGE is required to file a gas rate case every five years under this legislation. On August 2, 2013, BGE filed its infrastructure replacement plan and associated surcharge. The new surcharge rates are expected to take effect in the first quarter of 2014. BGE currently cannot predict the outcome of this proceeding or how much of the requested planned and related surcharge the MDPSC will approve.

2013 Maryland Electric and Gas Distribution Rate Case (Exelon and BGE). On May 17, 2013, BGE filed an application for increases of $101 million and $30 million to its electric and gas base rates, respectively, with the MDPSC. The requested rates of return on equity in the application are 10.50% and 10.35% for electric and gas distribution, respectively. In addition to these requested rate increases, BGE s application includes a request for recovery of incremental capital expenditures and operating costs associated with BGE s proposed short-term reliability improvement plan in response to a MDPSC order through a surcharge separate from base rates. On August 23, 2013, BGE filed an update to its rate request which altered the requested increase to electric base rates from $101 million to $83 million and the requested increase to gas base rates from $30 million to $24 million. The new electric and gas distribution base rates are expected to take effect in December 2013. BGE currently cannot predict the outcome of this proceeding or how much of the requested increases the MDPSC will approve.

Federal Regulatory Matters

Transmission Formula Rate (Exelon, ComEd and BGE). ComEd s and BGE s transmission rates are each established based on a FERC-approved formula.

ComEd s most recent annual formula rate update filed in April 2013 reflects 2012 actual costs plus forecasted 2013 capital additions. The update resulted in a revenue requirement of $488 million plus a $25 million adjustment related to the reconciliation of 2012 actual costs for a net revenue requirement of $513 million. This compares to the May 2012 updated revenue requirement of $450 million offset by a $5 million reduction related to the reconciliation of 2011 actual costs for a net revenue requirement of $445 million. The increase in the revenue requirement was primarily driven by increased plant investment, higher pension and post-retirement healthcare costs, and higher operating and maintenance costs. The 2013 net revenue requirement became effective June 1, 2013, and is being recovered over the period extending through May 31, 2014. The regulatory asset associated with the true-up is being amortized as the associated amounts are recovered through rates.

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

ComEd s updated formula transmission rate currently provides for a weighted average debt and equity return on transmission rate base of 8.70%, a decrease from the 8.91% return previously authorized. The decrease in return was primarily due to lower interest rates on ComEd s long-term debt outstanding. As part of the FERC-approved settlement of ComEd s 2007 transmission rate case, the rate of return on common equity is 11.5% and the common equity component of the ratio used to calculate the weighted average debt and equity return for the formula transmission rate is currently capped at 55%.

BGE s most recent annual formula rate update filed in April 2013 reflects actual 2012 expenses and investments plus forecasted 2013 capital additions. The update resulted in a revenue requirement of $158 million offset by a $1 million reduction related to the reconciliation of 2012 actual costs for a net revenue requirement of $157 million. This compares to the April 2012 updated revenue requirement of $156 million increased by $2 million related to the reconciliation of 2011 actual costs for a net revenue requirement of $158 million. The decrease in the revenue requirement was primarily driven by a lower realized rate of return and reduced rate base, offset partially by higher depreciation and operating and maintenance costs. The 2013 net revenue requirement became effective June 1, 2013, and is being recovered over the period extending through May 31, 2014. The regulatory asset associated with the true-up is being amortized as the associated amounts are recovered through rates.

BGE s updated formula transmission rate currently provides for a weighted average debt and equity return on transmission rate base of 8.35%, a decrease from the 8.43% return previously authorized. The decrease in return was primarily due to a debt issuance in 2012 and lower interest rates on BGE s debt outstanding. As part of the FERC-approved settlement in 2006 of BGE s 2005 transmission rate case, the base rate of return on common equity for BGE s electric transmission business for new transmission projects placed in service on and after January 1, 2006 is 11.3%, inclusive of a 50 basis point incentive for participating in PJM.

FERC Transmission Complaint (Exelon and BGE). On February 27, 2013, consumer advocates and regulators from the District of Columbia, New Jersey, Delaware and Maryland, and the Delaware Electric Municipal Cooperatives (the parties), filed a complaint at FERC against BGE and the Pepco Holdings, Inc. companies relating to their respective transmission formula rates. BGE s formula rate includes a 10.8% base rate of return on common equity for most investments included in its rate base. The parties seek a reduction in the base return on equity to 8.7% and changes to the formula rate process. FERC docketed the matter and set April 3, 2013 as the deadline for interventions, protests and answers. Under FERC rules, the earliest date from which the base return on equity could be adjusted and refunds required is the date of the complaint. On March 19, 2013, BGE filed a motion to dismiss or sever the complaint. As of September 30, 2013, BGE cannot predict the likelihood or a reasonable estimate of the amount of a change, if any, in the allowed base return on equity, or a reasonable estimate of the refund period start date. While BGE cannot predict the outcome of this matter, if FERC orders a reduction of BGE s base return on equity from 10.8% to 8.7%, the estimated annual impact would be a reduction in revenues of approximately $10 million.

PJM Transmission Rate Design and Operating Agreements (Exelon, ComEd, PECO and BGE). PJM Transmission Rate Design specifies the rates for transmission service charged to customers within PJM. Currently, ComEd, PECO and BGE incur costs based on the existing rate design, which charges customers based on the cost of the existing transmission facilities within their load zone and the cost of new transmission facilities based on those who benefit from those facilities. In April 2007, FERC issued an order concluding that PJM s current rate design for existing facilities is just and reasonable and should not be changed. In the same order, FERC held that the costs of new facilities 500 kV and above should be socialized across the entire PJM footprint and that the costs of new facilities less than 500 kV should be allocated to the customers of the new facilities who caused the need for those facilities. After FERC ultimately denied all requests for rehearing on all issues, several

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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. 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 that 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 June 30, 2006 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.

On October 11, 2012, the PJM Transmission Owners filed with FERC a cost allocation for new transmission facilities asking that the new cost allocation methodology apply to all transmission approved by the PJM Board on or after February 1, 2013. The proposed methodology is a hybrid methodology that would socialize 50% of the costs of new facilities at 500kV and above and double-circuit 345kV lines, and allocate the remaining 50% to direct beneficiaries. For all other facilities, the costs would be allocated to the direct beneficiaries. On March 22, 2013, FERC issued an order accepting the cost allocation with minor exceptions and requiring a compliance filing on those few issues within 120 days of the order. The compliance filing was made on July 22, 2013.

ComEd, PECO and BGE are committed to the construction of transmission facilities under their operating agreements with PJM to maintain system reliability. ComEd, PECO and BGE will work with PJM to continue to evaluate the scope and timing of any required construction projects. There were no significant changes in baseline project commitments for ComEd, PECO and BGE through the third quarter of 2013.

PJM Minimum Offer Price Rule (Exelon and Generation). PJM s capacity market rules include a Minimum Offer Price Rule (MOPR) that is intended to preclude sellers from artificially suppressing the competitive price signals for generation capacity. The proceedings leading to FERC s approval of the MOPR were extensive, and there have been numerous changes to the MOPR and litigation related to it since it was originally implemented. For example, in 2011 the parties disputed numerous elements of the MOPR including: (i) the default price that should apply to bids found subject to the MOPR, (ii) the duration of the MOPR and (iii) the application of the MOPR to self-supplying capacity and state-sponsored capacity. The FERC orders approving that MOPR have been appealed to the United States Court of Appeals for the Third Circuit. A resolution of that appeal is not expected until sometime in late 2013.

In May 2012 (based on the MOPR provisions the FERC approved in 2011), PJM announced the results of its capacity auction covering the delivery year ending May 31, 2016. Several new units with state-sanctioned subsidy contracts cleared in the auction at prices below the MOPR. Potentially, these states could expand such state-sanctioned subsidy programs or other states may seek to establish similar programs. Generation believed that further revisions to that MOPR were necessary to ensure that the potential to artificially reduce capacity auction prices is appropriately limited in PJM. In early December 2012, PJM filed a new MOPR for approval at the FERC, which Exelon believed would be more effective in preventing state-sanctioned subsidy contracts from artificially reducing capacity prices. Generation was actively involved in the process through which those MOPR changes were developed and supported the changes. On May 3, 2013, the FERC issued its order. While the

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

FERC order accepted certain aspects of the proposal that Exelon supported (such as applying the MOPR to all of PJM and not just certain zones within PJM), the FERC required PJM to retain a key element of its previous MOPR structure, the unit-specific exemption, an element that Exelon had supported removing. Several entities, including two capacity suppliers that Exelon has been working with sought rehearing of that order.

In May 2013 (based on the MOPR provisions the FERC approved earlier that month), PJM announced the results of its capacity auction covering the delivery year ending May 31, 2017. Exelon is working with PJM stakeholders on several proposed changes to the PJM tariff aimed at ensuring that capacity resources (including those with state-sanctioned subsidy contracts) cannot inappropriately affect capacity auction prices in PJM.

Reliability Pricing Model (Exelon, Generation and BGE). PJM s RPM Base Residual Auctions take place approximately 36 months ahead of the scheduled delivery year. The most recent auction for the delivery year ending May 31, 2017 occurred in May 2013.

License Renewals (Exelon and Generation). On June 22, 2011, Generation submitted applications to the NRC to extend the operating licenses of Limerick Units 1 and 2 by 20 years. The current operating licenses for Limerick Units 1 and 2 expire in 2024 and 2029, respectively. In June 2012, the United States Court of Appeals for the DC Circuit vacated the NRC s temporary storage rule on the grounds that the NRC should have conducted a more comprehensive environmental review to support the rule. The temporary storage rule (also referred to as the waste confidence decision) recognizes that licensees can safely store spent nuclear fuel at nuclear plants for up to 60 years beyond the original and renewed licensed operating life of the plants and that licensing renewal decisions do not require discussion of the environmental impact of spent fuel stored on site. In August 2012, the NRC placed a hold on issuing new or renewed operating licenses that depend on the temporary storage rule until the court s decision is addressed. In September 2012, the NRC directed NRC Staff to revise the temporary storage rule through rulemaking no later than September 6, 2014. Generation does not expect the NRC to issue license renewals until the end of 2014, at the earliest.

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

On August 29, 2012 and August 30, 2012, Generation submitted hydroelectric license applications to the FERC for 46-year licenses for the Conowingo Hydroelectric Project (Conowingo) and the Muddy Run Pumped Storage Facility Project (Muddy Run), respectively. Generation is working with stakeholders to resolve licensing issues, including: (1) water quality, (2) fish passage and habitat, and (3) sediment. On August 29, 2013, Exelon filed a water quality certification application pursuant to Section 401 of the Clean Water Act with PA DEP for Muddy Run, addressing these and other issues. The FERC extended the deadline to December 15, 2013 to file a water quality certification application pursuant to Section 401 of the Clean Water Act with the MDE for Conowingo. The stations are being depreciated over their useful lives, which includes the license renewal period. Although Generation expects that these licenses will be renewed, it cannot predict the conditions that may be imposed. Resolution of these issues may require a substantial increase in capital expenditures or may result in increased operating costs and significantly affect Generation s results of operations or financial position. Based on the latest FERC procedural schedule, the FERC licensing process is not expected to be completed prior to the expiration of Muddy Run s current license on August 31, 2014, and the expiration of Conowingo s license on September 1, 2014. However, the stations would continue to operate under annual licenses until FERC takes action on the 46-year license applications.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Regulatory Assets and Liabilities (Exelon, ComEd, PECO and BGE)

Exelon, ComEd, PECO and BGE each 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, ComEd, PECO and BGE as of September 30, 2013 and December 31, 2012. For additional information on the specific regulatory assets and liabilities, refer to Note 3 Regulatory Matters of the Exelon 2012 Form 10-K.

September 30, 2013	Exelon		ComEd		PECO		BGE	
	Current	Noncurrent	Current	Noncurrent	Current	Noncurrent	Current	Noncurrent
Regulatory assets								
Pension and other postretirement benefits	$ 308	$ 3,542	$	$	$	$	$	$
Deferred income taxes	12	1,424	3	65		1,296	9	63
AMI programs	4	129	4	29		48		52
AMI meter events		5				5		
Under-recovered distribution service costs	129	275	129	275				
Debt costs	12	60	9	56	3	4	1	9
Fair value of BGE long-term debt(a)		225						
Fair value of BGE supply contract(b)	29	3						
Severance	23	13	19				4	13
Asset retirement obligations		93		68		25		
MGP remediation costs	47	210	40	175	6	34	1	1
RTO start-up costs	2	1	2	1				
Under-recovered uncollectible accounts		31		31				
Renewable energy and associated RECs	16	106	16	106				
Energy and transmission programs	79		79					
Deferred storm costs	3	4					3	4
Electric generation-related regulatory asset	13	33					13	33
Rate stabilization deferral	68	175					68	175
Energy efficiency and demand response programs	75	144					75	144
Merger integration costs(c)	1	10					1	10
Under-recovered electric revenue decoupling(f)	8						8	
Other	48	26	34	13	13	7	1	5
Total regulatory assets	$ 877	$ 6,509	$ 335	$ 819	$ 22	$ 1,419	$ 184	$ 509

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

September 30, 2013	**Exelon**		**ComEd**		**PECO**		**BGE**	
	Current	**Noncurrent**	**Current**	**Noncurrent**	**Current**	**Noncurrent**	**Current**	**Noncurrent**
Regulatory liabilities								
Nuclear decommissioning	$	$ 2,593	$	$ 2,184	$	$ 409	$	$
Removal costs	103	1,420	82	1,202			21	218
Energy efficiency and demand response programs	85		49		36			
DLC Program Costs	1	10			1	10		
Energy efficiency Phase 2		14				14		
Electric distribution tax repairs	20	119			20	119		
Gas distribution tax repairs	8	40			8	40		
Energy and transmission programs	41	7		7	39(d)		2(h)	
Over-recovered gas and electric universal service fund costs	7				7			
Revenue subject to refund(e)	40		40					
Over-recovered gas revenue decoupling(f)	8						8	
Other	1	1						
Total regulatory liabilities	$ 314	$ 4,204	$ 171	$ 3,393	$ 111	$ 592	$ 31	$ 218

December 31, 2012	**Exelon**		**ComEd**		**PECO**		**BGE**	
	Current	**Noncurrent**	**Current**	**Noncurrent**	**Current**	**Noncurrent**	**Current**	**Noncurrent**
Regulatory assets								
Pension and other postretirement benefits	$ 304	$ 3,673	$	$	$	$	$	$
Deferred income taxes	14	1,382	5	62		1,255	9	65
AMI programs	3	70	3	10		29		31
AMI meter events		17				17		
Under-recovered distribution service costs	18	191	18	191				
Debt costs	14	68	11	62	3	6	1	9
Fair value of BGE long-term debt(a)		256						
Fair value of BGE supply contract(b)	77	12						
Severance	29	28	25	12			4	16
Asset retirement obligations		90		65		25		
MGP remediation costs	58	232	51	197	6	33	1	2
RTO start-up costs	3	2	3	2				
Under-recovered electric universal service fund costs	11				11			
Financial swap with Generation			226					
Renewable energy and associated RECs	18	49	18	49				
Energy and transmission programs	43		14		1(g)		28(h)	
DSP Program costs	1	3			1	3		
DSP II Program costs	1	2			1	2		
Deferred storm costs	3	6					3	6
Electric generation-related regulatory asset	16	40					16	40
Rate stabilization deferral	67	225					67	225
Energy efficiency and demand response programs	56	126					56	126
Under-recovered electric revenue decoupling(f)	5						5	
Other	23	25	14	16	9	8		2

Total regulatory assets	$ 764	$ 6,497	$ 388	$ 666	$ 32	$ 1,378	$ 190	$ 522

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

December 31, 2012	Exelon		ComEd		PECO		BGE	
	Current	Noncurrent	Current	Noncurrent	Current	Noncurrent	Current	Noncurrent
Regulatory liabilities								
Nuclear decommissioning	$	$ 2,397	$	$ 2,037	$	$ 360	$	$
Removal costs	97	1,406	75	1,192			22	214
Energy efficiency and demand response programs	131		43		88			
Electric distribution tax repairs	20	132			20	132		
Gas distribution tax repairs	8	46			8	46		
Over-recovered uncollectible accounts	6		6					
Energy and transmission programs	54		6		48(d)			
Over-recovered gas universal service fund costs	3				3			
Over-recovered AEPS costs	2				2			
Revenue subject to refund(e)	40		40					
Over-recovered gas revenue decoupling(f)	7						7	
Total regulatory liabilities	$ 368	$ 3,981	$ 170	$ 3,229	$ 169	$ 538	$ 29	$ 214

(a) Represents the regulatory asset recorded at Exelon Corporate for the difference in the fair value of the long-term debt of BGE as of the merger date. The asset is amortized over the life of the underlying debt. See Note 11 Debt and Credit Agreements for additional information.
(b) Represents the regulatory asset recorded at Exelon Corporate representing the fair value of BGE's supply contracts as of the close of the merger date. BGE is allowed full recovery of the costs of its electric and gas supply contracts through approved, regulated rates. The asset is amortized over a period of approximately 3 years.
(c) Relates to integration costs to achieve distribution synergies related to the merger transaction.
(d) Includes $18 million related to the DSP program, $13 million related to the over-recovered natural gas costs under the PGC and $8 million related to over-recovered electric transmission costs as of September 30, 2013. As of December 31, 2012, includes $47 million related to the over-recovered electric supply costs under the GSA and $1 million related to the over-recovered natural gas costs under the PGC.
(e) Primarily represents the regulatory liability for revenue subject to refund recorded pursuant to the ICC s order in the 2007 Rate Case. See above for discussion regarding the 2007 Rate Case.
(f) Represents the electric and gas distribution costs recoverable from or refundable to customers under BGE s decoupling mechanism.
(g) Relates to under-recovered transmission costs.
(h) Relates to $2 million of over-recovered natural electric supply costs as of September 30, 2013. As of December 31, 2012, includes $9 million of under-recovered electric supply costs and $19 million of under-recovered natural gas supply costs.

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Purchase of Receivables Programs (Exelon, ComEd, PECO, and BGE)

ComEd, PECO and BGE are required, under separate legislation and regulations in Illinois, Pennsylvania and Maryland, respectively, to purchase certain receivables from retail electric and natural gas suppliers. For retail suppliers participating in the utilities consolidated billing, ComEd, PECO and BGE must purchase their customer accounts receivables. ComEd and BGE purchase receivables at a discount to primarily recover uncollectible accounts expense from the suppliers. PECO is required to purchase receivables at face value and permitted to recover uncollectible accounts expense from customers through distribution rates. Exelon, ComEd, PECO and BGE do not record unbilled commodity receivables under the POR programs. Purchased billed receivables are classified in Other accounts receivable, net on Exelon s, ComEd s, PECO s and BGE s Consolidated Balance Sheets. The following tables provide information about the purchased receivables of the Registrants as of September 30, 2013 and December 31, 2012.

As of September 30, 2013	Exelon	ComEd	PECO	BGE
Purchased receivables(a)	$ 285	$ 124	$ 78	$ 83
Allowance for uncollectible accounts(b)	(31)	(18)	(7)	(6)
Purchased receivables, net	$ 254	$ 106	$ 71	$ 77

As of December 31, 2012	Exelon	ComEd	PECO	BGE
Purchased receivables(a)	$ 191	$ 55	$ 65	$ 71
Allowance for uncollectible accounts(b)	(21)	(9)	(6)	(6)
Purchased receivables, net	$ 170	$ 46	$ 59	$ 65

(a) PECO's gas POR program became effective on January 1, 2012 and includes a 1% discount on purchased receivables in order to recover the implementation costs of the program. If the costs are not fully recovered when PECO files its next gas distribution rate case, PECO will propose a mechanism to recover the remaining implementation costs as a distribution charge to low volume transportation customers or apply future discounts on purchased receivables from natural gas suppliers serving those customers.

(b) For ComEd and BGE, reflects the incremental allowance for uncollectible accounts recorded, which is in addition to the purchase discount. For ComEd, the incremental uncollectible accounts expense is recovered through its Purchase of Receivables with Consolidated Billing (PORCB) tariff.

6. Investment in Constellation Energy Nuclear Group, LLC (Exelon and Generation)

As a result of the Constellation merger, Generation owns a 50.01% interest in CENG, a nuclear generation business. Generation's total equity in earnings (losses) on the investment in CENG is as follows:

	Three Months Ended September 30, 2013	Three Months Ended September 30, 2012
Equity investment income	$ 68	$ 58
Amortization of basis difference in CENG	(31)	(57)
Total equity in earnings CENG	$ 37	$ 1

	Nine Months Ended September 30, 2013	For the Period March 12, through September 30, 2012
Equity investment income (loss)	$ 93	$ 53
Amortization of basis difference in CENG	(88)	(131)
Total equity in earnings (losses) CENG	$ 5	$ (78)

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

As of March 12, 2012, Generation had an initial basis difference of approximately $204 million between the initial carrying value of its investment in CENG and its underlying equity in CENG. This basis difference resulted from the requirement to record the investment in CENG at fair value under purchase accounting while the underlying assets and liabilities within CENG continue to be accounted for on a historical cost basis. Generation is amortizing this basis difference over the respective useful lives of the assets and liabilities of CENG or as those assets and liabilities affect the earnings of CENG.

Based on tax sharing provisions contained in the operating agreement for CENG, Generation may be eligible for distributions from its investment in CENG in excess of its 50.01% ownership interest. Through purchase accounting, Generation has recorded the fair value of expected future distributions. When these distributions are realized, Generation will record a reduction in its investment in CENG. Any distributions in excess of Generation s investment in CENG would be recorded in earnings.

Related Party Transactions (Exelon and Generation)

CENG

Generation has an agreement under which it is purchasing 85% of the output of CENG s nuclear plants that is not sold to third parties under pre-existing firm and unit contingent PPAs through 2014. Beginning on January 1, 2015 and continuing to the end of the life of the respective plants, Generation will purchase on a unit contingent basis 50.01% of the output of CENG s nuclear plants, and EDF will purchase on a unit contingent basis 49.99% of the output.

In addition to the PPA, Generation has a power services agency agreement (PSAA) with the CENG plants, which expires on December 31, 2014. The PSAA is a five-year agreement under which Generation provides scheduling, asset management and billing services to the CENG plants for a specified monthly fee. The charges for services reflect the cost of the services.

In addition to the PSAA, Exelon has a shared services agreement (SSA) with CENG, which expires in 2017. Pursuant to an agreement between Exelon and EDF, the pricing in the SSA for services reflect actual costs determined on the same basis that BSC charges its affiliates for similar services subject to an annual cap for most SSA services provided.

The affect of transactions under these agreements on Exelon s and Generation s Consolidated Financial Statements is summarized below:

Agreement	Income/(Expense) Three Months Ended September 30, 2013	Income/(Expense) Nine Months Ended September 30, 2013	Income Statement Classification	Accounts Receivable/ (Accounts Payable) At September 30, 2013
PPA	$ (269)	$ (748)	Purchased power and fuel	$ (76)
PSAA	1	3	Operating revenues	
SSA	10	32	Operating revenues	4

Agreement	Income/(Expense) Three Months Ended September 30, 2012	Income/(Expense) For the Period March 12 through September 30, 2012	Income Statement Classification	Accounts Receivable/ (Accounts Payable) At September 30, 2012
PPA	$ (282)	$ (541)	Purchased power and fuel	$ (86)
PSAA	1	2	Operating revenues	
SSA	14	30	Operating revenues	5

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

At the closing, Generation, CENG and subsidiaries of CENG will execute a Nuclear Operating Services Agreement pursuant to which Generation will operate the CENG nuclear generation fleet owned by CENG subsidiaries and provide corporate and administrative services for the remaining life of the CENG nuclear plants as if they were a part of the Generation nuclear fleet, subject to EDFI s rights as a member of CENG. CENG will reimburse Generation for its direct and allocated costs for such services. The Nuclear Operating Services Agreement will replace the SSA. In addition, at the closing the PSAA will be amended and extended until the complete and permanent cessation of operation of the CENG generation plants.

At closing, Generation will make a $400 million loan to CENG bearing interest at 5.25% per annum, payable out of specified available cash flows of CENG. Immediately following receipt of the proceeds of such loan, CENG will make a $400 million special distribution to EDFI. The parties will also execute a Fourth Amended and Restated Operating Agreement for CENG, pursuant to which, among other things, CENG will commit to make preferred distributions to Generation (after repayment of the $400 million loan) quarterly out of specified available cash flows, until Generation has received aggregate distributions of $400 million plus a return of 8.5% per annum from the date of the special distribution to EDFI.

Generation and EDFI will also enter into a Put Option Agreement at closing pursuant to which EDFI will have the option, exercisable beginning in 2016 and thereafter until June 30, 2022, to sell its 49.99% interest in CENG to Generation for a fair market value price determined by agreement of the parties, or absent agreement, a third party arbitration process. The appraisers determining fair market value of EDF s 49.99% interest in CENG under the Put Option Agreement are instructed to take into account all rights and obligations under the CENG Operating Agreement, including Generation s rights with respect to any unpaid aggregate preferred distributions and the related return, and the value of Generation s rights to other distributions. The beginning of the exercise period will be accelerated if Exelon s affiliates cease to own a majority of CENG and exercise a related right to terminate the Nuclear Operating Services Agreement. In addition, under limited circumstances, the period for exercise of the put option may be extended for 18 months.

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

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

7. Impairment of Long-Lived Assets (Exelon and Generation)

Long-Lived Assets (Exelon and Generation)

Generation evaluates long-lived assets for recoverability whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. In the third quarter of 2013, lower projected wind production and a decline in power prices suggested that the carrying value of certain wind projects may be impaired. Generation concluded that the estimated undiscounted future cash flows and fair value of eleven wind projects, primarily located in West Texas and Minnesota, were less than their respective carrying values at September 30, 2013. The fair value analysis was primarily based on the income approach using significant unobservable inputs (Level 3) including revenue and generation forecasts, projected capital and maintenance expenditures and discount rates. As a result, long-lived assets held and used with a carrying amount of approximately $75 million were written down to their fair value of $32 million and a pre-tax impairment charge of $39 million, net of the impairment amount attributable to non-controlling interests for certain of the projects, was recorded during the third quarter in operating and maintenance expense in Exelon s and Generation s Consolidated Statements of Operations.

Nuclear Uprate Program (Exelon and Generation)

Generation is engaged in individual projects as part of a planned power uprate program across its nuclear fleet. When economically viable, the projects take advantage of new production and measurement technologies, new materials and application of expertise gained from a half-century of nuclear power operations. Based on ongoing reviews, the nuclear uprate implementation plan has been adjusted in both the first and second quarters of 2013 to cancel certain projects. During the first quarter of 2013, 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. For these cancelled projects, Generation recorded approximately $21 million of operating and maintenance expense during the first quarter of 2013 to accrue remaining costs and reverse previously capitalized costs. During the second quarter of 2013, market conditions prompted Generation to cancel the previously deferred extended power uprate projects at the LaSalle and Limerick nuclear stations. For these cancelled projects, Generation recorded a pre-tax charge during the second quarter of 2013 to operating and maintenance expense and interest expense of approximately $92 million and $8 million, respectively, to accrue remaining costs and reverse the previously capitalized costs.

Like-Kind Exchange Transaction (Exelon)

Prior to the PECO/Unicom Merger in October 2000, UII, LLC (formerly Unicom Investments, Inc.) (UII), a wholly owned subsidiary of Exelon, entered into a like-kind exchange transaction pursuant to which approximately $1.6 billion was invested in coal-fired generating station leases located in Georgia and Texas with two separate entities unrelated to Exelon. The generating stations were leased back to such entities as part of the transaction. See Note 12 Income Taxes for further information. For financial accounting purposes, the investments are accounted for as direct financing lease investments. UII holds the leasehold interests in the generating stations in several separate bankruptcy remote, special purpose companies it directly or indirectly wholly owns. The lease agreements provide the lessees with fixed purchase options at the end of the lease terms. If the lessees do not exercise the fixed purchase options, Exelon has the ability to require the lessees to return the leasehold interests or to arrange for a third party to bid on a service contract for a period following the lease term. If Exelon chooses the service contract option, the leasehold interests will be returned to Exelon at the end of the term of the service contract. In any event, Exelon will be subject to residual value risk if the lessees do not exercise the fixed purchase options. This risk is partially mitigated by the fair value of the scheduled payments under the service contract. However, such payments are not guaranteed. Further, the term of the service contract is less than the expected remaining useful life of the plants and, therefore, Exelon s exposure to residual value risk will not be mitigated by payments under the service contract in this remaining period. In the fourth quarter of 2000, under the terms of the lease agreements, UII received a prepayment of $1.2 billion for all rent, which reduced the investment in the leases. There are no minimum scheduled lease payments to be received over the remaining term of the leases.

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

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 value. Exelon estimates the fair value of the residual value of its direct financing lease investments under the income approach, which uses a discounted cash flow analysis, which takes into consideration the expected revenues to be generated and costs to be incurred to operate the plants over their remaining useful lives subsequent to the lease end dates. 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 review performed in the second quarter of 2013, the estimated residual value of one of Exelon s direct financing leases experienced an other than temporary decline given reduced long-term energy and capacity price expectations. As a result, Exelon recorded a $14 million pre-tax impairment charge in the second quarter of 2013, which was recorded in investments and operating and maintenance in the Consolidated Balance Sheet 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.

As of December 31, 2012, Exelon concluded that the estimated fair values of the residual values at the end of the lease terms exceeded the residual values established at the lease dates.

At September 30, 2013 and December 31, 2012, the components of the net investment in long-term leases were as follows:

	September 30, 2013	December 31, 2012
Estimated residual value of leased assets	$ 1,465	$ 1,492
Less: unearned income	774	807
Net investment in long-term leases	$ 691	$ 685

8. Goodwill (Exelon and ComEd)

Goodwill

Under the authoritative guidance for the accounting 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 that would more likely than not reduce the fair value of the ComEd reporting unit below its carrying amount. 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.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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. Consistent with prior impairment tests, the estimated fair value of ComEd was determined using 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 management s best estimate of projected cash flows for ComEd s business. The discounted cash flow analysis used in the interim goodwill impairment assessment 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 the interim assessment indicated no 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 the early termination of EIMA or changes in significant assumptions, including the 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 interim goodwill test, the estimated fair value of ComEd would have needed to decrease by more than 10 percent for ComEd to fail the first step of the impairment test.

ComEd s 2013 annual goodwill impairment test is being performed as of November 1, 2013.

9. Fair Value of Financial Assets and Liabilities (Exelon, Generation, ComEd, PECO and BGE)

Fair Value of Financial Liabilities Recorded at the Carrying Amount

The following tables present the carrying amounts and fair values of the Registrants short-term liabilities, long-term debt, SNF obligation, trust preferred securities (long-term debt to financing trusts or junior subordinated debentures), and preferred securities as of September 30, 2013 and December 31, 2012:

Exelon

	September 30, 2013				
	Carrying Amount	Fair Value			
		Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 217	$ 3	$ 214	$	$ 217
Long-term debt (including amounts due within one year)	19,565		19,203	1,065	20,268
Long-term debt to financing trusts	648			631	631
SNF obligation	1,021		782		782

	December 31, 2012				
	Carrying Amount	Fair Value			
		Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 214	$ 4	$ 210	$	$ 214
Long-term debt (including amounts due within one year)	18,745		20,244	276	20,520
Long-term debt to financing trusts	648			664	664
SNF obligation	1,020		763		763
Preferred securities of subsidiary	87		82		82

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Generation

	September 30, 2013				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 21	$	$ 21	$	$ 21
Long-term debt (including amounts due within one year)	7,809		6,744	1,047	7,791
SNF obligation	1,021		782		782

	December 31, 2012				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Long-term debt (including amounts due within one year)	$ 7,483	$	$ 7,591	$ 258	$ 7,849
SNF obligation	1,020		763		763

ComEd

	September 30, 2013				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 153	$	$ 153	$	$ 153
Long-term debt (including amounts due within one year)	5,674		6,240	17	6,257
Long-term debt to financing trust	206			195	195

	December 31, 2012				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Long-term debt (including amounts due within one year)	$ 5,567	$	$ 6,530	$ 18	$ 6,548
Long-term debt to financing trust	206			212	212

PECO

	September 30, 2013				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Long-term debt (including amounts due within one year)	$ 2,496	$	$ 2,678	$	$ 2,678
Long-term debt to financing trusts	184			182	182

	December 31, 2012				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 210	$	$ 210	$	$ 210
Long-term debt (including amounts due within one year)	1,947		2,264		2,264
Long-term debt to financing trusts	184			188	188
Preferred securities	87		82		82

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

BGE

	September 30, 2013				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 43	$ 3	$ 40	$	$ 43
Long-term debt (including amounts due within one year)	2,045		2,204		2,204
Long-term debt to financing trusts	258			254	254

	December 31, 2012				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Long-term debt (including amounts due within one year)	$ 2,178	$	$ 2,468	$	$ 2,468
Long-term debt to financing trusts	258			263	263

Short-Term Liabilities. The short-term liabilities included in the tables above are comprised of short-term borrowings (Level 2), short-term notes payable related to PECO s accounts receivable agreement (Level 2), and dividends payable (included in other current liabilities) (Level 1). The Registrants carrying amounts of the short-term liabilities are representative of fair value because of the short-term nature of these instruments. See Note 11 Debt and Credit Agreements for additional information on PECO s accounts receivable agreement.

Long-Term Debt. The fair value amounts of Exelon s taxable debt securities (Level 2) are determined by a valuation model that is based on a conventional discounted cash flow methodology and utilizes assumptions of current market pricing curves. In order to incorporate the credit risk of the Registrants into the discount rates, Exelon obtains pricing (i.e., U.S. Treasury rate plus credit spread) based on trades of existing Exelon debt securities as well as debt securities of other issuers in the electric utility sector with similar credit ratings in both the primary and secondary market, across the Registrants debt maturity spectrum. The credit spreads of various tenors obtained from this information are added to the appropriate benchmark U.S. Treasury rates in order to determine the current market yields for the various tenors. The yields are then converted into discount rates of various tenors that are used for discounting the respective cash flows of the same tenor for each bond or note.

The fair value of Generation s non-government-backed fixed rate project financing debt (Level 3) is based on market and quoted prices for its own and other project financing debt with similar risk profiles. Given the low trading volume in the project financing debt market, the price quotes used to determine fair value will reflect certain qualitative factors, such as market conditions, investor demand, new developments that might significantly impact the project cash flows or off-taker credit, and other circumstances related to the project (e.g., political and regulatory environment). The fair value of Generation s government-back fixed rate project financing debt (Level 3) is largely based on a discounted cash flow methodology that is similar to the taxable debt securities methodology described above. Due to the lack of market trading data on similar debt, the discount rates are derived based on the original loan interest rate spread to the applicable Treasury rate as well as a current market curve derived from government-backed securities. Variable rate project financing debt resets on a quarterly basis and the carrying value approximates fair value.

The Registrants also have tax-exempt debt (Level 3). Due to low trading volume in this market, qualitative factors, such as market conditions, investor demand, and circumstances related to the issuer (i.e., political and regulatory environment), may be incorporated into the credit spreads that are used to obtain the fair value as described above.

SNF Obligation. The carrying amount of Generation s SNF obligation (Level 2) is derived from a contract with the DOE to provide for disposal of SNF from Generation s nuclear generating stations. When determining the fair value of the obligation, the future carrying amount of the SNF obligation estimated to be settled in 2025 is calculated by compounding the current book value of the SNF obligation at the 13-week Treasury rate. The compounded obligation amount is discounted back to present value using Generation s discount rate, which is calculated using the same methodology as described above for the taxable debt securities, and an estimated maturity date of 2025.

Long-Term Debt to Financing Trusts. Exelon s long-term debt to financing trusts is valued based on publicly traded securities issued by the financing trusts. Due to low trading volume of these securities, qualitative factors, such as market conditions, investor demand, and circumstances related to each issue, this debt is classified as Level 3.

Preferred Securities. The fair value of these securities is determined based on the last closing price prior to quarter end, less accrued interest. The securities are registered with the SEC and are public. PECO redeemed all outstanding series of preferred securities on May 1, 2013. See Note 17 Earnings Per Share and Equity for additional information.

Recurring Fair Value Measurements

Exelon records the fair value of assets and liabilities in accordance with the hierarchy established by the authoritative guidance for fair value measurements. The hierarchy prioritizes the inputs to valuation techniques used to measure fair value into three levels as follows:

Level 1 quoted prices (unadjusted) in active markets for identical assets or liabilities that the Registrants have the ability to access as of the reporting date. Financial assets and liabilities utilizing Level 1 inputs include active exchange-traded equity securities and funds, certain exchange-based derivatives, and money market funds.

Level 2 inputs other than quoted prices included within Level 1 that are directly observable for the asset or liability or indirectly observable through corroboration with observable market data. Financial assets and liabilities utilizing Level 2 inputs include fixed income securities, derivatives, commingled and mutual investment funds priced at NAV per fund share and fair value hedges.

Level 3 unobservable inputs, such as internally developed pricing models or third-party valuations for the asset or liability due to little or no market activity for the asset or liability. Financial assets and liabilities utilizing Level 3 inputs include infrequently traded securities and derivatives, investments priced using an alternative pricing mechanism, and middle market lending using third party valuations.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Exelon

The following tables present assets and liabilities measured and recorded at fair value on Exelon s Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy as of September 30, 2013 and December 31, 2012:

As of September 30, 2013	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets				
Cash equivalents(a)	$ 1	$	$	$ 1
Nuclear decommissioning trust fund investments				
Cash equivalents	558			558
Equity				
Individually held	1,600			1,600
Exchange traded funds	110			110
Commingled funds		2,114		2,114
Equity funds subtotal	1,710	2,114		3,824
Fixed income				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	938			938
Debt securities issued by states of the United States and political subdivisions of the states		295		295
Debt securities issued by foreign governments		84		84
Corporate debt securities		1,712		1,712
Federal agency mortgage-backed securities		16		16
Commercial mortgage-backed securities (non-agency)		41		41
Residential mortgage-backed securities (non-agency)		7		7
Mutual funds		29		29
Fixed income subtotal	938	2,184		3,122
Middle market lending			245	245
Other debt obligations		14		14
Nuclear decommissioning trust fund investments subtotal(b)	3,206	4,312	245	7,763
Pledged assets for Zion Station decommissioning				
Cash equivalents		25		25
Equity				
Individually held	4			4
Equity funds subtotal	4			4
Fixed income				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	89	7		96
Debt securities issued by states of the United States and political subdivisions of the states		24		24
Corporate debt securities		217		217

Federal agency mortgage-backed securities		7		7
Fixed income subtotal	89	255		344
Middle market lending			106	106
Pledged assets for Zion Station decommissioning subtotal(c)	93	280	106	479

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

As of September 30, 2013	**Level 1**	**Level 2**	**Level 3**	**Total**
Rabbi trust investments				
Cash equivalents	2			2
Mutual funds(d)(e)	49			49
Rabbi trust investments subtotal	51			51
Commodity derivative assets				
Economic hedges	540	2,541	703	3,784
Proprietary trading	666	1,184	174	2,024
Effect of netting and allocation of collateral(f)	(1,251)	(2,785)	(311)	(4,347)
Commodity derivative assets subtotal	(45)	940	566	1,461
Interest rate and foreign currency derivative assets	34	49		83
Effect of netting and allocation of collateral	(33)	(2)		(35)
Interest rate and foreign currency derivative assets subtotal	1	47		48
Other investments	1		11	12
Total assets	3,308	5,579	928	9,815
Liabilities				
Commodity derivative liabilities				
Economic hedges	(764)	(1,718)	(363)	(2,845)
Proprietary trading	(686)	(1,135)	(155)	(1,976)
Effect of netting and allocation of collateral(f)	1,359	2,843	291	4,493
Commodity derivative liabilities subtotal(h)	(91)	(10)	(227)	(328)
Interest rate and foreign currency derivative liabilities	(34)	(17)		(51)
Effect of netting and allocation of collateral	33	2		35
Interest rate and foreign currency derivative liabilities subtotal	(1)	(15)		(16)
Deferred compensation obligation		(108)		(108)
Total liabilities	(92)	(133)	(227)	(452)
Total net assets	$ 3,216	$ 5,446	$ 701	$ 9,363

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

As of December 31, 2012	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents(a)	$ 995	$	$	$ 995
Nuclear decommissioning trust fund investments				
Cash equivalents	245			245
Equity				
Individually held	1,480			1,480
Commingled funds		1,933		1,933
Equity funds subtotal	1,480	1,933		3,413
Fixed income				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	1,057			1,057
Debt securities issued by states of the United States and political subdivisions of the states		321		321
Debt securities issued by foreign governments		93		93
Corporate debt securities		1,788		1,788
Federal agency mortgage-backed securities		24		24
Commercial mortgage-backed securities (non-agency)		45		45
Residential mortgage-backed securities (non-agency)		11		11
Mutual funds		23		23
Fixed income subtotal	1,057	2,305		3,362
Middle market lending			183	183
Other debt obligations		15		15
Nuclear decommissioning trust fund investments subtotal(b)	2,782	4,253	183	7,218
Pledged assets for Zion decommissioning				
Cash equivalents		23		23
Equity				
Individually held	14			14
Commingled funds		9		9
Equity funds subtotal	14	9		23
Fixed income				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	118	12		130
Debt securities issued by states of the United States and political subdivisions of the states		37		37
Corporate debt securities		249		249
Federal agency mortgage-backed securities		49		49
Commercial mortgage-backed securities (non-agency)		6		6
Fixed income subtotal	118	353		471
Middle market lending			89	89
Other debt obligations		1		1

Pledged assets for Zion Station decommissioning subtotal(c)	132	386	89	607
Rabbi trust investments				
Cash equivalents	2			2
Mutual funds(d)(e)	69			69
Rabbi trust investments subtotal	71			71

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

As of December 31, 2012	**Level 1**	**Level 2**	**Level 3**	**Total**
Commodity derivative assets				
Economic hedges	861	3,173	641	4,675
Proprietary trading	1,042	2,078	73	3,193
Effect of netting and allocation of collateral(f)	(1,823)	(4,175)	(58)	(6,056)
Commodity derivative assets subtotal(g)	80	1,076	656	1,812
Interest rate and foreign currency derivative assets		114		114
Effect of netting and allocation of collateral		(51)		(51)
Interest rate and foreign currency derivative assets subtotal		63		63
Other Investments	2		17	19
Total assets	4,062	5,778	945	10,785
Liabilities				
Commodity derivative liabilities				
Economic hedges	(1,041)	(2,289)	(236)	(3,566)
Proprietary trading	(1,084)	(1,959)	(78)	(3,121)
Effect of netting and allocation of collateral(f)	2,042	4,020	25	6,087
Commodity derivative liabilities subtotal(g)(h)	(83)	(228)	(289)	(600)
Interest rate and foreign currency derivative liabilities		(84)		(84)
Effect of netting and allocation of collateral		51		51
Interest rate and foreign currency derivative liabilities subtotal		(33)		(33)
Deferred compensation obligation		(102)		(102)
Total liabilities	(83)	(363)	(289)	(735)
Total net assets	$ 3,979	$ 5,415	$ 656	$ 10,050

(a) Excludes certain cash equivalents considered to be held-to-maturity and not reported at fair value.

(b) Excludes net assets of $13 million and $30 million at September 30, 2013 and December 31, 2012, respectively. These items consist of receivables related to pending securities sales, interest and dividend receivables, and payables related to pending securities purchases.

(c) Excludes net assets of $7 million at both September 30, 2013 and December 31, 2012. These items consist of receivables related to pending securities sales, interest and dividend receivables, and payables related to pending securities purchases.

(d) The mutual funds held by the Rabbi trusts include $49 million related to deferred compensation at September 30, 2013, and $53 million related to deferred compensation and $16 million related to Supplemental Executive Retirement Plan at December 31, 2012. .

(e) Excludes $30 million and $28 million of the cash surrender value of life insurance investments at September 30, 2013 and December 31, 2012, respectively.

(f) Includes collateral postings (received) from counterparties. Collateral posted (received) from counterparties, net of collateral paid to counterparties, totaled $108 million, $58 million and $(20) million allocated to Level 1, Level 2 and Level 3 mark-to-market derivatives, respectively, as of September 30, 2013. Collateral posted (received) from counterparties, net of collateral paid to counterparties, totaled $219 million, $(155) million and $(33) million allocated to Level 1, Level 2 and Level 3 mark-to-market derivatives, respectively, as of December 31, 2012.

(g) The Level 3 balance does not include current assets for Generation and current liabilities for ComEd of $226 million at December 31, 2012, related to the fair value of Generation s financial swap contract with ComEd.

(h) The Level 3 balance includes the current and noncurrent liability of $16 million and $106 million at September 30, 2013, respectively, and $18 million and $49 million at December 31, 2012, respectively, related 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 presents the fair value reconciliation of Level 3 assets and liabilities measured at fair value on a recurring basis during the three and nine months ended September 30, 2013 and 2012:

Three Months Ended September 30, 2013	**Nuclear Decommissioning Trust Fund Investments**	**Pledged Assets for Zion Station Decommissioning**	**Mark-to-Market Derivatives**	**Other Investments**	**Total**
Balance as of June 30, 2013	$ 240	$ 111	$ 431	$ 11	$ 793
Total realized / unrealized losses					
Included in net income			(32)(a)		(32)
Included in other comprehensive income					
Included in regulatory assets	(1)		(37)		(38)
Included in payable for Zion Station decommissioning					
Change in collateral			(30)		(30)
Purchases, sales, issuances and settlements					
Purchases	23	10	8		41
Sales	(14)	(15)			(29)
Settlements	(3)				(3)
Transfers into Level 3			4		4
Transfers out of Level 3			(5)		(5)
Balance as of September 30, 2013	$ 245	$ 106	$ 339	$ 11	$ 701
The amount of total gains included in income attributed to the change in unrealized gains related to assets and liabilities held for the three months ended September 30, 2013	$	$	$ 51	$	$ 51

Nine Months Ended September 30, 2013	**Nuclear Decommissioning Trust Fund Investments**	**Pledged Assets for Zion Station Decommissioning**	**Mark-to-Market Derivatives**	**Other Investments**	**Total**
Balance as of December 31, 2012	$ 183	$ 89	$ 367	$ 17	$ 656
Total realized / unrealized gains (losses)					
Included in net income	2		(1)(a)		1
Included in other comprehensive income					
Included in regulatory assets	8		(55)(b)		(47)
Included in payable for Zion Station decommissioning		1			1
Change in collateral			13		13
Purchases, sales, issuances and settlements					
Purchases	90	43	16	2	151
Sales	(27)	(27)	(8)	(8)	(70)
Settlements	(11)				(11)
Transfers into Level 3			11		11
Transfers out of Level 3			(4)		(4)
Balance as of September 30, 2013	$ 245	$ 106	$ 339	$ 11	$ 701

The amount of total gains included in income attributed to the change in unrealized gains related to assets and liabilities held for the nine months ended September 30, 2013	$	1	$	$	159	$	$ 160

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

(a) Includes the reclassification of $83 million and $160 million of realized losses due to the settlement of derivative contracts recorded in results of operations for the three and nine months ended September 30, 2013.

(b) Excludes decreases in fair value of $11 million and realized losses reclassified due to settlements of $215 million associated with Generation s financial swap contract with ComEd for the nine months ended September 30, 2013. All items eliminate upon consolidation in Exelon's Consolidated Financial Statements.

Three Months Ended September 30, 2012	**Nuclear Decommissioning Trust Fund Investments**	**Pledged Assets for Zion Station Decommissioning**	**Mark-to-Market Derivatives**	**Other Investments**	**Total**
Balance as of June 30, 2012	$ 54	$ 59	$ 295	$ 17	$ 425
Total realized / unrealized gains (losses)					
Included in net income			(97)(a)		(97)
Included in other comprehensive income					
Included in regulatory assets	2		41(b)		43
Included in payable for Zion Station decommissioning		1			1
Change in collateral			(15)		(15)
Purchases, sales, issuances and settlements					
Purchases	14	4			18
Sales					
Transfers into Level 3					
Transfers out of Level 3					
Balance as of September 30, 2012	$ 70	$ 64	$ 224	$ 17	$ 375
The amount of total losses included in income attributed to the change in unrealized losses related to assets and liabilities held for the three months ended September 30, 2012	$	$	$ (42)	$	$ (42)

Nine Months Ended September 30, 2012	**Nuclear Decommissioning Trust Fund Investments**	**Pledged Assets for Zion Decommissioning**	**Mark-to-Market Derivatives**	**Other Investments**	**Total**
Balance as of December 31, 2011	$ 13	$ 37	$ 17	$	$ 67
Total realized / unrealized gains (losses)					
Included in net income			(78)(a)		(78)
Included in other comprehensive income					
Included in regulatory assets	2		36(b)		38
Included in payable for Zion Station decommissioning					
Change in collateral			(7)		(7)
Purchases, sales, issuances and settlements					
Purchases	55	36	329(c)	17	437
Sales		(9)			(9)
Transfers into Level 3			(34)		(34)
Transfers out of Level 3			(39)		(39)

Balance as of September 30, 2012	$ 70	$ 64	$ 224	$ 17	$ 375
The amount of total gains included in income attributed to the change in unrealized gains related to assets and liabilities held for the nine months ended September 30, 2012	$	$	$ 62	$	$ 62

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

(a) Includes the reclassification of $55 million and $140 million of realized losses due to the settlement of derivative contracts recorded in results of operations for the three and nine months ended September 30, 2012, respectively.
(b) Excludes $35 million of decreases in fair value and $86 million of increases in fair value and $119 million and $427 million of realized losses due to settlements for the three and nine months ended September 30, 2012 of Generation s financial swap contract with ComEd, which eliminates upon consolidation in Exelon s Consolidated Financial Statements.
(c) Includes $310 million of fair value from contracts and $14 million of other investments acquired as a result of the merger.

The following tables present the income statement classification of the total realized and unrealized gains (losses) included in income for Level 3 assets and liabilities measured at fair value on a recurring basis during the three and nine months ended September 30, 2013 and 2012:

	Operating Revenue	Purchased Power and Fuel	Other, net(a)
Total gains (losses) included in income for the three months ended September 30, 2013	$ (39)	$ 7	$
Total gains (losses) included in income for the nine months ended September 30, 2013	$ (61)	$ 60	$ 2
Change in the unrealized gains relating to assets and liabilities held for the three months ended September 30, 2013	$ 42	$ 9	$
Change in the unrealized gains relating to assets and liabilities held for the nine months ended September 30, 2013	$ 81	$ 78	$ 1

	Operating Revenue	Purchased Power and Fuel	Other, net
Total gains (losses) included in income for the three months ended September 30, 2012	$ (101)	$ 4	$
Total losses included in income for the nine months ended September 30, 2012	$ (78)	$	$
Change in the unrealized gains (losses) relating to assets and liabilities held for the three months ended September 30, 2012	$ (43)	$ 1	$
Change in the unrealized gains (losses) relating to assets and liabilities held for the nine months ended September 30, 2012	$ 82	$ (20)	$

(a) Other, net activity consists of realized and unrealized gains (losses) included in income for the NDT funds held by Generation.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Generation

The following tables present assets and liabilities measured and recorded at fair value on Generation s Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy as of September 30, 2013 and December 31, 2012:

As of September 30, 2013	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets				
Cash equivalents	$ 674	$	$	$ 674
Nuclear decommissioning trust fund investments				
Cash equivalents	558			558
Equity				
Individually held	1,600			1,600
Exchange traded funds	110			110
Commingled funds		2,114		2,114
Equity funds subtotal	1,710	2,114		3,824
Fixed income				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	938			938
Debt securities issued by states of the United States and political subdivisions of the states		295		295
Debt securities issued by foreign governments		84		84
Corporate debt securities		1,712		1,712
Federal agency mortgage-backed securities		16		16
Commercial mortgage-backed securities (non-agency)		41		41
Residential mortgage-backed securities (non-agency)		7		7
Mutual funds		29		29
Fixed income subtotal	938	2,184		3,122
Middle market lending			245	245
Other debt obligations		14		14
Nuclear decommissioning trust fund investments subtotal(b)	3,206	4,312	245	7,763
Pledged assets for Zion Station decommissioning				
Cash equivalents		25		25
Equity				
Individually held	4			4
Equity funds subtotal	4			4
Fixed income				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	89	7		96
Debt securities issued by states of the United States and political subdivisions of the states		24		24
Corporate debt securities		217		217

Federal agency mortgage-backed securities		7		7
Fixed income subtotal	89	255		344
Middle market lending			106	106
Pledged assets for Zion Station decommissioning subtotal(c)	93	280	106	479
Rabbi trust investments				
Mutual funds(d)	12			12
Rabbi trust investments subtotal	12			12

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

As of September 30, 2013	**Level 1**	**Level 2**	**Level 3**	**Total**
Commodity derivative assets				
Economic hedges	540	2,541	703	3,784
Proprietary trading	666	1,184	174	2,024
Effect of netting and allocation of collateral(e)	(1,251)	(2,785)	(311)	(4,347)
Commodity derivative assets subtotal	(45)	940	566	1,461
Interest rate and foreign currency derivative assets	34	36		70
Effect of netting and allocation of collateral	(33)	(2)		(35)
Interest rate and foreign currency derivative assets subtotal	1	34		35
Other investments	1		11	12
Total assets	3,942	5,566	928	10,436
Liabilities				
Commodity derivative liabilities				
Economic hedges	(764)	(1,718)	(241)	(2,723)
Proprietary trading	(686)	(1,135)	(155)	(1,976)
Effect of netting and allocation of collateral(e)	1,359	2,843	291	4,493
Commodity derivative liabilities subtotal	(91)	(10)	(105)	(206)
Interest rate and foreign currency derivative liabilities	(34)	(17)		(51)
Effect of netting and allocation of collateral	33	2		35
Interest rate and foreign currency derivative liabilities subtotal	(1)	(15)		(16)
Deferred compensation obligation		(27)		(27)
Total liabilities	(92)	(52)	(105)	(249)
Total net assets	$ 3,850	$ 5,514	$ 823	$ 10,187

As of December 31, 2012	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets				
Cash equivalents(a)	$ 487	$	$	$ 487
Nuclear decommissioning trust fund investments				
Cash equivalents	245			245
Equity				
Individually held	1,480			1,480
Commingled funds		1,933		1,933
Equity funds subtotal	1,480	1,933		3,413

Fixed income				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	1,057			1,057
Debt securities issued by states of the United States and political subdivisions of the states		321		321
Debt securities issued by foreign governments		93		93
Corporate debt securities		1,788		1,788
Federal agency mortgage-backed securities		24		24
Commercial mortgage-backed securities (non-agency)		45		45
Residential mortgage-backed securities (non-agency)		11		11
Mutual funds		23		23
Fixed income subtotal	1,057	2,305		3,362
Middle market lending			183	183
Other debt obligations		15		15
Nuclear decommissioning trust fund investments subtotal(b)	2,782	4,253	183	7,218

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

As of December 31, 2012	**Level 1**	**Level 2**	**Level 3**	**Total**
Pledged assets for Zion Station decommissioning				
Cash equivalents		23		23
Equity				
Individually held	14			14
Commingled funds		9		9
Equity funds subtotal	14	9		23
Fixed income				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	118	12		130
Debt securities issued by states of the United States and political subdivisions of the states		37		37
Corporate debt securities		249		249
Federal agency mortgage-backed securities		49		49
Commercial mortgage-backed securities (non-agency)		6		6
Fixed income subtotal	118	353		471
Middle market lending			89	89
Other debt obligations		1		1
Pledged assets for Zion Station decommissioning subtotal(c)	132	386	89	607
Rabbi trust investments				
Cash equivalents	1			1
Mutual funds(d)	13			13
Rabbi trust investments subtotal	14			14
Commodity derivative assets				
Economic hedges	861	3,173	867	4,901
Proprietary trading	1,042	2,078	73	3,193
Effect of netting and allocation of collateral(e)	(1,823)	(4,175)	(58)	(6,056)
Commodity and foreign currency assets subtotal(f)	80	1,076	882	2,038
Interest rate and foreign currency derivative assets		101		101
Effect of netting and allocation of collateral		(51)		(51)
Interest rate and foreign currency derivative assets subtotal		50		50
Other investments	2		17	19
Total assets	3,497	5,765	1,171	10,433
Liabilities				
Commodity derivative liabilities				
Economic hedges	(1,041)	(2,289)	(169)	(3,499)
Proprietary trading	(1,084)	(1,959)	(78)	(3,121)

Effect of netting and allocation of collateral(e)	2,042	4,020	25	6,087
Commodity derivative liabilities subtotal	(83)	(228)	(222)	(533)
Interest rate derivative liabilities		(84)		(84)
Effect of netting and allocation of collateral		51		51
Interest rate and foreign currency derivative liabilities		(33)		(33)
Deferred compensation obligation		(28)		(28)
Total liabilities	(83)	(289)	(222)	(594)
Total net assets	$ 3,414	$ 5,476	$ 949	$ 9,839

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

(a) Excludes certain cash equivalents considered to be held-to-maturity and not reported at fair value.
(b) Excludes net assets of $13 million and $30 million at September 30, 2013 and December 31, 2012, respectively. These items consist of receivables related to pending securities sales, interest and dividend receivables, and payables related to pending securities purchases.
(c) Excludes net assets of $7 at both September 30, 2013 December 31, 2012. These items consist of receivables related to pending securities sales, interest and dividend receivables, and payables related to pending securities purchases.
(d) Excludes $9 million and $8 million of the cash surrender value of life insurance investments at September 30, 2013 and December 31, 2012, respectively.
(e) Includes collateral postings (received) from counterparties. Collateral posted (received) from counterparties, net of collateral paid to counterparties, totaled $108 million, $58 million and $(20) million allocated to Level 1, Level 2 and Level 3 mark-to-market derivatives, respectively, as of September 30, 2013. Collateral posted (received) from counterparties, net of collateral paid to counterparties, totaled $219 million, $(155) million and $(33) million allocated to Level 1, Level 2 and Level 3 mark-to-market derivatives, respectively, as of December 31, 2012.
(f) The level 3 balance includes current assets for Generation of $226 million at December 31, 2012, related to the fair value of Generation s financial swap contract with ComEd, which eliminates upon consolidation in Exelon s Consolidated Financial Statements.

The following tables present the fair value reconciliation of Level 3 assets and liabilities measured at fair value on a recurring basis during the three and nine months ended September 30, 2013 and 2012:

Three Months Ended September 30, 2013	**Nuclear Decommissioning Trust Fund Investments**	**Pledged Assets for Zion Station Decommissioning**	**Mark-to-Market Derivatives**	**Other Investments**	**Total**
Balance as of June 30, 2013	$ 240	$ 111	$ 516	$ 11	$ 878
Total realized / unrealized gains (losses)					
Included in net income			(32)(a)		(32)
Included in noncurrent payables to affiliates	(1)				(1)
Change in collateral			(30)		(30)
Purchases, sales, issuances and settlements					
Purchases	23	10	8		41
Sales	(14)	(15)			(29)
Settlements	(3)				(3)
Transfers into Level 3			4		4
Transfers out of Level 3			(5)		(5)
Balance as of September 30, 2013	$ 245	$ 106	$ 461	$ 11	$ 823
The amount of total gains included in income attributed to the change in unrealized gains related to assets and liabilities held for the three months ended September 30, 2013	$	$	$ 51	$	$ 51

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Nine Months Ended September 30, 2013	Nuclear Decommissioning Trust Fund Investments	Pledged Assets for Zion Station Decommissioning	Mark-to-Market Derivatives	Other Investments	Total
Balance as of December 31, 2012	$ 183	$ 89	$ 660	$ 17	$ 949
Total realized / unrealized gains (losses)					
Included in net income	2		(8)(a)(b)		(6)
Included in other comprehensive income			(219)(b)		(219)
Included in noncurrent payables to affiliates	8				8
Included in payable for Zion Station decommissioning		1			1
Change in collateral			13		13
Purchases, sales, issuances and settlements					
Purchases	90	43	16	2	151
Sales	(27)	(27)	(8)	(8)	(70)
Settlements	(11)				(11)
Transfers into Level 3			11		11
Transfers out of Level 3			(4)		(4)
Balance as of September 30, 2013	$ 245	$ 106	$ 461	$ 11	$ 823
The amount of total gains included in income attributed to the change in unrealized gains related to assets and liabilities held for the nine months ended September 30, 2013	$ 1	$	$ 148	$	$ 149

(a) Includes the reclassification of $83 million and $156 million of realized losses due to the settlement of derivative contracts recorded in results of operations for the three and nine months ended September 30, 2013, respectively.

(b) Includes $11 million of increases in fair value and realized losses due to settlements of $215 million associated with Generation's financial swap contract with ComEd for the nine months ended September 30, 2013. This position eliminates upon consolidation in Exelon's Consolidated Financial Statements.

Three Months Ended September 30, 2012	Nuclear Decommissioning Trust Fund Investments	Pledged Assets for Zion Station Decommissioning	Mark-to-Market Derivatives	Other Investments	Total
Balance as of June 30, 2012	$ 54	$ 59	$ 912	$ 17	$ 1,042
Total realized / unrealized gains (losses)					
Included in net income			(112)(a)		(112)
Included in other comprehensive income			(139)(b)		(139)
Included in noncurrent payables to affiliates	2				2
Included in payable for Zion Station decommissioning		1			1
Changes in collateral			(15)		(15)
Purchases, sales, issuances and settlements					
Purchases	14	4			18
Sales					
Balance as of September 30, 2012	$ 70	$ 64	$ 646	$ 17	$ 797
	$	$	$ (77)	$	$ (77)

The amount of total losses included in income attributed to the change in unrealized losses related to assets and liabilities held for the three months ended September 30, 2012

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Nine Months Ended September 30, 2012	Nuclear Decommissioning Trust Fund Investments	Pledged Assets for Zion Station Decommissioning	Mark-to-Market Derivatives	Other Investments	Total
Balance as of December 31, 2011	$ 13	$ 37	$ 817	$	$ 867
Total realized / unrealized gains (losses)					
Included in net income			(109)(a)		(109)
Included in other comprehensive income			(311)(b)		(311)
Included in noncurrent payables to affiliates	2				2
Changes in collateral			(7)		(7)
Purchases, sales, issuances and settlements					
Purchases	55	36	329(c)	17	437
Sales		(9)			(9)
Transfers into Level 3			(34)		(34)
Transfers out of Level 3			(39)		(39)
Balance as of September 30, 2012	$ 70	$ 64	$ 646	$ 17	$ 797
The amount of total gains included in income attributed to the change in unrealized gains related to assets and liabilities held for the nine months ended September 30, 2012	$	$	$ 1	$	$ 1

(a) Includes the reclassification of $35 million and $110 million of realized losses due to the settlement of derivative contracts recorded in results of operations for the three and nine months ended September 30, 2012, respectively.

(b) Includes $35 million of decreases in fair value and $86 million of increases in fair value and realized losses due to settlements of $119 million and $427 million associated with Generation's financial swap contract with ComEd for the three and nine months ended September 30, 2012, respectively. This position was re-designated as a cash flow hedge prior to the merger date. All prospective changes in fair value and reclassifications of realized amounts are being recorded to income offset by the amortization of the frozen mark in OCI. All items eliminate upon consolidation in Exelon s Consolidated Financial Statements.

(c) Includes $310 million of fair value from contracts and $14 million of other investments acquired as a result of the merger.

The following tables present the income statement classification of the total realized and unrealized gains (losses) included in income for Level 3 assets and liabilities measured at fair value on a recurring basis during the three and nine months ended September 30, 2013 and 2012:

	Operating Revenue	Purchased Power and Fuel	Other, net(a)
Total gains (losses) included in net income for the three months ended September 30, 2013	$ (39)	$ 7	$
Total gains (losses) included in net income for the nine months ended September 30, 2013	$ (67)	$ 59	$ 2
Change in the unrealized gains relating to assets and liabilities held for the three months ended September 30, 2013	$ 42	$ 9	$
Change in the unrealized gains relating to assets and liabilities held for the nine months ended September 30, 2013	$ 71	$ 77	$ 1

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	Operating Revenue	Purchased Power and Fuel	Other, net
Total gains (losses) included in net income for the three months ended September 30, 2012	$ (116)	$ 4	$
Total losses included in net income for the nine months ended September 30, 2012	$ (109)	$	$
Change in the unrealized gains (losses) relating to assets and liabilities held for the three months ended September 30, 2012	$ (78)	$ 1	$
Change in the unrealized gains (losses) relating to assets and liabilities held for the nine months ended September 30, 2012	$ 21	$ (20)	$

(a) Other, net activity consists of realized and unrealized gains (losses) included in income for the NDT funds held by Generation.

ComEd

The following tables present assets and liabilities measured and recorded at fair value on ComEd s Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy as of September 30, 2013 and December 31, 2012:

As of September 30, 2013	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets				
Cash equivalents	$	$	$	$
Rabbi trust investments				
Mutual funds	5			5
Rabbi trust investments subtotal	5			5
Total assets	5			5
Liabilities				
Deferred compensation obligation		(8)		(8)
Mark-to-market derivative liabilities(a)			(122)	(122)
Total liabilities		(8)	(122)	(130)
Total net assets (liabilities)	$ 5	$ (8)	$ (122)	$ (125)

As of December 31, 2012	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets				
Cash equivalents	$ 111	$	$	$ 111
Rabbi trust investments				
Mutual funds	8			8
Rabbi trust investments subtotal	8			8
Total assets	119			119

Liabilities				
Deferred compensation obligation		(8)		(8)
Mark-to-market derivative liabilities(a)(b)			(293)	(293)
Total liabilities		(8)	(293)	(301)
Total net assets (liabilities)	$ 119	$ (8)	$ (293)	$ (182)

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

(a) The Level 3 balance includes the current and noncurrent liability of $16 million and $106 million at September 30, 2013, respectively, and $18 million and $49 million at December 31, 2012, respectively, related to floating-to-fixed energy swap contracts with unaffiliated suppliers.
(b) The Level 3 balance includes the current liability of $226 million at December 31, 2012, related to the fair value of ComEd's financial swap contract with Generation which eliminated upon consolidation in Exelon's Consolidated Financial Statements.

The following tables present the fair value reconciliation of Level 3 assets and liabilities measured at fair value on a recurring basis during the three and nine months ended September 30, 2013 and 2012:

Three Months Ended September 30, 2013	**Mark-to-Market Derivatives**
Balance as of June 30, 2013	$ (85)
Total realized / unrealized gains included in regulatory assets(b)	(37)
Balance as of September 30, 2013	$ (122)

Nine Months Ended September 30, 2013	**Mark-to-Market Derivatives**
Balance as of December 31, 2012	$ (293)
Total realized / unrealized gains included in regulatory assets(a)(b)	171
Balance as of September 30, 2013	$ (122)

(a) Includes $11 million of decreases in fair value and realized gains due to settlements of $215 million associated with ComEd's financial swap contract with Generation for the nine months ended September 30, 2013. All items eliminate upon consolidation in Exelon's Consolidated Financial Statements.
(b) Includes $37 million and $57 million of increases in the fair value and realized losses due to settlements of $1 million and $5 million recorded in purchased power expense associated with floating-to-fixed energy swap contracts with unaffiliated suppliers for the three and nine months ended September 30, 2013, respectively.

Three Months Ended September 30, 2012	**Mark-to-Market Derivatives**
Balance as of June 30, 2012	$ (617)
Total realized / unrealized gains included in regulatory assets(a)(b)	195
Balance as of September 30, 2012	$ (422)

Nine Months Ended September 30, 2012	**Mark-to-Market Derivatives**
Balance as of December 31, 2011	$ (800)

Total realized / unrealized gains included in regulatory assets(a)(b)		378
Balance as of September 30, 2012	$	(422)

(a) Includes $35 million of increases in fair value and $86 million of decreases in fair value and realized gains due to settlements of $119 million and $427 million of associated with ComEd's financial swap contract with Generation for the three and nine months ended September 30, 2012, respectively. All items eliminate upon consolidation in Exelon's Consolidated Financial Statements.

(b) Includes $40 million and $33 million of increases in the fair value and realized losses due to settlements of $1 million and $2 million recorded in purchased power expense associated with floating-to-fixed energy swap contracts with unaffiliated suppliers for the three and nine months ended September 30, 2012, respectively.

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

PECO

The following tables present assets and liabilities measured and recorded at fair value on PECO's Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy as of September 30, 2013 and December 31, 2012:

As of September 30, 2013	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents	$ 583	$	$	$ 583
Rabbi trust investments				
Mutual funds(a)	9			9
Rabbi trust investments subtotal	9			9
Total assets	592			592
Liabilities				
Deferred compensation obligation		(16)		(16)
Total liabilities		(16)		(16)
Total net assets (liabilities)	$ 592	$ (16)	$	$ 576

As of December 31, 2012	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents	$ 346	$	$	$ 346
Rabbi trust investments				
Mutual funds(a)	9			9
Rabbi trust investments subtotal	9			9
Total assets	355			355
Liabilities				
Deferred compensation obligation		(18)		(18)
Total liabilities		(18)		(18)
Total net assets (liabilities)	$ 355	$ (18)	$	$ 337

(a) Excludes $14 million and $13 million of the cash surrender value of life insurance investments at September 30, 2013 and December 31, 2012, respectively.

PECO had no Level 3 assets or liabilities measured at fair value on a recurring basis during the three and nine months ended September 30, 2013 and 2012.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

BGE

The following tables present assets and liabilities measured and recorded at fair value on BGE s Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy as of September 30, 2013 and December 31, 2012:

As of September 30, 2013	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets				
Cash equivalents	$ 53	$	$	$ 53
Rabbi trust investments				
Mutual funds(a)	5			5
Rabbi trust investments subtotal	5			5
Total assets	58			58
Liabilities				
Deferred compensation obligation		(5)		(5)
Total liabilities		(5)		(5)
Total net assets (liabilities)	$ 58	$ (5)	$	$ 53

As of December 31, 2012	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets				
Cash equivalents	$ 33	$	$	$ 33
Rabbi trust investments				
Mutual funds	5			5
Rabbi trust investments subtotal	5			5
Total assets	38			38
Liabilities				
Deferred compensation obligation		(5)		(5)
Total liabilities		(5)		(5)
Total net assets (liabilities)	$ 38	$ (5)	$	$ 33

BGE had no Level 3 assets or liabilities measured at fair value on a recurring basis during the three and nine months ended September 30, 2013 and 2012.

Valuation Techniques Used to Determine Fair Value

The following describes the valuation techniques used to measure the fair value of the assets and liabilities shown in the tables above.

Cash Equivalents (Exelon, Generation, ComEd, PECO and BGE). The Registrants cash equivalents include investments with maturities of three months or less when purchased. The cash equivalents shown in the fair value tables are comprised of investments in mutual and money market funds. The fair values of the shares of these funds are based on observable market prices and, therefore, have been categorized in Level 1 in the fair value hierarchy.

Nuclear Decommissioning Trust Fund Investments and Pledged Assets for Zion Station Decommissioning (Exelon and Generation). The trust fund investments have been established to fund Generation s nuclear decommissioning obligations as required by the NRC. The NDT funds hold debt and equity securities directly

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

and indirectly through commingled funds. Generation s investment policies place limitations on the types and investment grade ratings of the securities that may be held by the trusts. These policies limit the trust funds exposures to investments in highly illiquid markets and other alternative investments. Investments with maturities of three months or less when purchased, including certain short-term fixed income securities are considered cash equivalents and included in the recurring fair value measurements hierarchy as Level 1.

With respect to individually held equity securities and exchange traded funds, 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 and exchange traded funds, held directly by the trust funds are based on quoted prices in active markets and are categorized in Level 1. Equity securities held individually and exchange traded funds 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.

Equity and fixed income commingled funds and fixed income mutual funds are maintained by investment companies and hold certain investments in accordance with a stated set of fund objectives. The fair values of fixed income commingled and mutual funds held within the trust funds, which generally hold short-term fixed income securities and are not subject to restrictions regarding the purchase or sale of shares, are derived from observable prices. The objectives of the remaining equity commingled funds in which Exelon and Generation invest primarily seek to track the performance of certain equity indices by purchasing equity securities to replicate the capitalization and characteristics of the indices. In general, equity commingled funds are redeemable daily. Equity and fixed income 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. See Note 13 Nuclear Decommissioning for further discussion on the NDT fund investments.

Middle market lending funds are investments in loans or managed funds which invest in private companies. Generation elected the fair value option for its investments held by certain limited partnerships that invest in middle market lending managed funds. The fair value of these loans is determined using a combination of valuation models including cost models, market models, and income models. Investments in middle market lending are categorized as Level 3 because the fair value of these securities is based largely on inputs that are unobservable and utilize complex valuation models. Investments in middle market lending typically cannot be redeemed until maturity of the term loan.

Rabbi Trust Investments (Exelon, Generation, ComEd, PECO and BGE). The Rabbi trusts were established to hold assets related to deferred compensation plans existing for certain active and retired members of Exelon s executive management and directors. The investments in the Rabbi trusts are included in investments

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in the Registrants Consolidated Balance Sheets. The investments are in fixed-income commingled funds and mutual funds, including short-term investment 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. Fixed-income commingled funds and mutual funds, such as money market funds, are publicly quoted and have been categorized as Level 1 given the clear observability of the prices.

Mark-to-Market Derivatives (Exelon, Generation, and ComEd). Derivative contracts are traded in both exchange-based and non-exchange-based markets. Exchange-based derivatives that are valued using unadjusted quoted prices in active markets are categorized in Level 1 in the fair value hierarchy. Certain derivatives pricing is verified using indicative price quotations available through brokers or over-the-counter, on-line exchanges and are categorized in Level 2. These price quotations reflect the average of the bid-ask, mid-point prices and are obtained from sources that the Registrants believe provide the most liquid market for the commodity. The price quotations are reviewed and corroborated to ensure the prices are observable and representative of an orderly transaction between market participants. This includes consideration of actual transaction volumes, market delivery points, bid-ask spreads and contract duration. The remainder of derivative contracts are valued using the Black model, an industry standard option valuation model. The Black model takes into account inputs such as contract terms, including maturity, and market parameters, including assumptions of the future prices of energy, interest rates, volatility, credit worthiness and credit spread. For derivatives that trade in liquid markets, such as generic forwards, swaps and options, model inputs are generally observable. Such instruments are categorized in Level 2. The Registrants derivatives are predominately at liquid trading points. For derivatives that trade in less liquid markets with limited pricing information model inputs generally would include both observable and unobservable inputs. These valuations may include an estimated basis adjustment from an illiquid trading point to a liquid trading point for which active price quotations are available. Such instruments are categorized in Level 3.

Transfers in and out of levels are recognized as of the end of the reporting period the transfer occurred. Given derivatives categorized within Level 1 are valued using exchange-based quoted prices within observable periods, transfers between Level 2 and Level 1 were not material. Transfers into Level 2 from Level 3 generally occur when the contract tenure becomes more observable. Transfers into Level 3 from Level 2 generally occur due to changes in market liquidity or assumptions for certain commodity contracts.

Exelon may utilize fixed-to-floating interest rate swaps, which are typically designated as fair value hedges, as a means to achieve its targeted level of variable-rate debt as a percent of total debt. In addition, the Registrants may utilize interest rate derivatives to lock in interest rate levels in anticipation of future financings. These interest rate derivatives are typically designated as cash flow hedges. Exelon determines the current fair value by calculating the net present value of expected payments and receipts under the swap agreement, based on and discounted by the market's expectation of future interest rates. Additional inputs to the net present value calculation may include the contract terms, counterparty credit risk and other market parameters. As these inputs are based on observable data and valuations of similar instruments, the interest rate swaps are categorized in Level 2 in the fair value hierarchy. See Note 10 Derivative Financial Instruments for further discussion on mark-to-market derivatives.

Deferred Compensation Obligations (Exelon, Generation, ComEd, PECO and BGE). The Registrants deferred compensation plans allow participants to defer certain cash compensation into a notional investment account. The Registrants include such plans in other current and noncurrent liabilities in their Consolidated Balance Sheets. The value of the Registrants deferred compensation obligations is based on the market value of the participants notional investment accounts. The notional investments are comprised primarily of mutual funds, which are based on observable market prices. However, since the deferred compensation obligations themselves are not exchanged in an active market, they are categorized in Level 2 in the fair value hierarchy.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Additional Information Regarding Level 3 Fair Value Measurements (Exelon, Generation, ComEd)

Mark-to-Market Derivatives (Exelon, Generation, ComEd). For valuations that include both observable and unobservable inputs, if the unobservable input is determined to be significant to the overall inputs, the entire valuation is categorized in Level 3. This includes derivatives valued using indicative price quotations whose contract tenure extends into unobservable periods. In instances where observable data is unavailable, consideration is given to the assumptions that market participants would use in valuing the asset or liability. This includes assumptions about market risks such as liquidity, volatility and contract duration. Such instruments are categorized in Level 3 as the model inputs generally are not observable. Exelon s RMC approves risk management policies and objectives for risk assessment, control and valuation, counterparty credit approval, and the monitoring and reporting of risk exposures. The RMC is chaired by the chief risk officer and includes the chief financial officer, corporate controller, general counsel, treasurer, vice president of strategy, vice president of audit services and officers representing Exelon s business units. The RMC reports to the Exelon Board of Directors on the scope of the risk management activities and is responsible for approving all valuation procedures at Exelon. Forward price curves for the power market utilized by the front office to manage the portfolio, are reviewed and verified by the middle office, and used for financial reporting by the back office. The Registrants consider credit and nonperformance risk in the valuation of derivative contracts categorized in Level 2 and 3, including both historical and current market data in its assessment of credit and nonperformance risk by counterparty. Due to master netting agreements and collateral posting requirements, the impacts of credit and nonperformance risk were not material to the financial statements.

Disclosed below is detail surrounding the Registrants significant Level 3 valuations. The calculated fair value includes marketability discounts for margining provisions and notional size. Generation s Level 3 balance generally consists of forward sales and purchases of power and natural gas, coal purchases, certain transmission congestion contracts, and project financing debt. Generation utilizes various inputs and factors including market data and assumptions that market participants would use in pricing assets or liabilities as well as assumptions about the risks inherent in the inputs to the valuation technique. The inputs and factors include forward commodity prices, commodity price volatility, contractual volumes, delivery location, interest rates, credit quality of counterparties and credit enhancements.

For commodity derivatives, the primary input to the valuation models is the forward commodity price curve for each instrument. Forward commodity price curves are derived by risk management for liquid locations and by the traders and portfolio managers for illiquid locations. All locations are reviewed and verified by risk management considering published exchange transaction prices, executed bilateral transactions, broker quotes, and other observable or public data sources. The relevant forward commodity curve used to value each of the derivatives depends on a number of factors, including commodity type, delivery location, and delivery period. Price volatility varies by commodity and location. When appropriate, Generation discounts future cash flows using risk free interest rates with adjustments to reflect the credit quality of each counterparty for assets and Generation s own credit quality for liabilities. The level of observability of a forward commodity price is generally due to the delivery location and delivery period. Certain delivery locations including PJM West Hub (for power) and Henry Hub (for natural gas) are highly liquid and prices are observable for up to three years in the future. The observability period of volatility is generally shorter than the underlying power curve used in option valuations. The forward curve for a less liquid location is estimated by using the forward curve from the liquid location and applying a spread to represent the cost to transport the commodity to the delivery location. This spread does not typically represent a majority of the instrument s market price. As a result, the change in fair value is closely tied to liquid market movements and not a change in the applied spread. The change in fair value associated with a change in the spread is generally immaterial. An average spread calculated across all Level 3 power and gas delivery locations is generally less than $1.96 and $0.18 for power and natural gas, respectively. Many of the commodity derivatives are short term in nature and thus a majority of the fair value

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

may be based on observable inputs even though the contract as a whole must be classified as Level 3. See ITEM 3. 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 10 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 September 30, 2013(c)	Valuation Technique	Unobservable Input	Range
Mark-to-market derivatives	Economic Hedges (Generation)(a)	$ 462	Discounted Cash Flow	Forward power price	$15 - $103
				Forward gas price	$3.51 - $5.97
			Option Model	Volatility percentage	27% - 107%
Mark-to-market derivatives	Proprietary trading (Generation)(a)	$ 19	Discounted Cash Flow	Forward power price	$14 - $103
			Option Model	Volatility percentage	14% - 28%
Mark-to-market derivatives (ComEd)		$ (122)	Discounted Cash Flow	Forward heat rate(b)	8 - 9
				Marketability reserve	3.5% - 8%
				Renewable factor	84% - 130%

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 $20 million as of September 30, 2013.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Type of trade		Fair Value at December 31, 2012(d)	Valuation Technique	Unobservable Input	Range
Mark-to-market derivatives	Economic Hedges (Generation)(a)	$ 473	Discounted Cash Flow	Forward power price	$14 - $79
				Forward gas price	$3.26 - $6.27
			Option Model	Volatility percentage	28% - 132%
Mark-to-market derivatives	Proprietary trading (Generation)(a)	$ (6)	Discounted Cash Flow	Forward power price	$15 - $106
			Option Model	Volatility percentage	16% - 48%
Mark-to-market derivatives	Transactions with Affiliates (Generation and ComEd)(b)	$ 226	Discounted Cash Flow	Marketability reserve	8% - 9%
Mark-to-market derivatives (ComEd)		$ (67)	Discounted Cash Flow	Forward heat rate(c)	8 - 9.5
				Marketability reserve	3.5% - 8.3%
				Renewable factor	81% - 123%

a) The valuation techniques, unobservable inputs and ranges are the same for the asset and liability positions.
b) Includes current assets for Generation and current liabilities for ComEd of $226 million, related to the fair value of the five-year financial swap contract between Generation and ComEd, which eliminates in consolidation.
c) Quoted forward natural gas rates are utilized to project the forward power curve for the delivery of energy at specified future dates. The natural gas curve is extrapolated beyond its observable period to the end of the contract s delivery.
d) The fair values do not include cash collateral held on level three positions of $33 million as of December 31, 2012.

The inputs listed above would have a direct impact on the fair values of the above instruments if they were adjusted. The significant unobservable inputs used in the fair value measurement of Generation s commodity derivatives are forward commodity prices and for options is 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, the fair value of these loans is determined using a combination of valuations 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

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well as other factors that may impact value. Significant judgment is required in the applications of discounts or premiums applied to the prices of comparable companies for factors such as size, marketability and relative performance.

Because Generation relies on third-party fund managers to develop the quantitative unobservable inputs without adjustment for the valuations of its middle market lending, 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 middle market lending, Generation reviewed independent valuations and reviewed the assumptions in the detailed pricing models used by the fund managers.

As of September 30, 2013, Generation has outstanding commitments to invest in middle market lending of approximately $192 million. These commitments will be funded by Generation s existing nuclear decommissioning trust funds.

10. Derivative Financial Instruments (Exelon, Generation, ComEd, PECO and BGE)

The Registrants are exposed to certain risks related to ongoing business operations. The primary risks managed by using derivative instruments are commodity price risk and interest rate risk.

Commodity Price Risk (Exelon, Generation, ComEd, PECO and BGE)

To the extent the amount of energy Exelon generates differs from the amount of energy it has contracted to sell, the Registrants are exposed to market fluctuations in the prices of electricity, fossil fuels and other commodities. The Registrants employ established policies and procedures to manage their risks associated with market fluctuations by entering into physical and financial derivative contracts, including swaps, futures, forwards, options and short-term and long-term commitments to purchase and sell energy and energy-related products. The Registrants believe these instruments, which are classified as either economic hedges or non-derivatives, mitigate exposure to fluctuations in commodity prices.

Derivative accounting guidance requires that derivative instruments be recognized as either assets or liabilities at fair value, with changes in fair value of the derivative recognized in earnings each period. Other accounting treatments are available through special election and designation, provided they meet specific, restrictive criteria both at the time of designation and on an ongoing basis. These alternative permissible accounting treatments include normal purchase normal sale (NPNS), cash flow hedge, and fair value hedge. For commodity transactions, effective with the date of merger with Constellation, Generation no longer utilizes the special election provided for by the cash flow hedge designation and de-designated all of its existing cash flow hedges prior to the merger. Because the underlying forecasted transactions remain at least reasonably possible, the fair value of the effective portion of these cash flow hedges was frozen in accumulated OCI and reclassified to results of operations when the forecasted purchase or sale of the energy commodity occurs, or becomes probable of not occurring. None of Constellation s designated cash flow hedges for commodity transactions prior to the merger were re-designated as cash flow hedges. The effect of this decision is that all derivative economic hedges for commodities are recorded at fair value through earnings for the combined company, referred to as economic hedges in the following tables. The Registrants have applied the NPNS scope exception to certain derivative contracts for the forward sale of generation, power procurement agreements, and natural gas supply agreements. Non-derivative contracts for access to additional generation and certain sales to load-serving entities are accounted for primarily under the accrual method of accounting, which is further discussed in Note 19 Commitments and Contingencies of the Exelon 2012 Form 10-K. Additionally, Generation is exposed to certain market risks through its proprietary trading activities. The proprietary trading activities are a complement to Generation s energy marketing portfolio but represent a small portion of Generation s overall energy marketing activities.

Economic Hedging. The Registrants are exposed to commodity price risk primarily relating to changes in the market price of electricity, fossil fuels, and other commodities associated with price movements resulting from changes in supply and demand, fuel costs, market liquidity, weather conditions, governmental regulatory and environmental policies, and other factors. Within Exelon, Generation has the most exposure to commodity price risk. Generation uses a variety of derivative and non-derivative instruments to manage the commodity price risk of its electric generation facilities, including power sales, fuel and energy purchases, natural gas transportation and pipeline capacity agreements and other energy-related products marketed and purchased. In order to manage these risks, Generation may enter into fixed-price derivative or non-derivative contracts to hedge the variability in future cash flows from forecasted sales of energy and purchases of fuel and energy. The objectives for entering into such hedges include fixing the price for a portion of anticipated future electricity sales at a level that provides an acceptable return on electric generation operations, fixing the price of a portion of anticipated fuel purchases for the operation of power plants, and fixing the price for a portion of anticipated energy purchases to supply load-serving customers. The portion of forecasted transactions hedged may vary based upon management s policies and hedging objectives, the market, weather conditions, operational and other factors. Generation is also exposed to differences between the locational settlement prices of certain economic hedges and the hedged generating units. This price difference is actively managed through other instruments which include derivative congestion products, whose changes in fair value are recognized in earnings each period, and auction revenue rights, which are accounted for on an accrual basis.

In general, increases and decreases in forward market prices have a positive and negative impact, respectively, on Generation s owned and contracted generation positions that have not been hedged. Generation hedges commodity price risk on a ratable basis over three-year periods. As of September 30, 2013, the percentage of expected generation hedged for the major reportable segments was 97%-100%, 84%-87%, and 48%-51% for 2013, 2014, and 2015, respectively. The percentage of expected generation hedged is the amount of equivalent sales divided by the expected generation. Expected generation represents the amount of energy estimated to be generated or purchased through owned or contracted capacity. Equivalent sales represent all hedging products, which include economic hedges and certain non-derivative contracts including, Generation s sales to ComEd, PECO and BGE to serve their retail load.

In order to fulfill a requirement of the Illinois Settlement Legislation, Generation and ComEd entered into a five-year financial swap contract that expired May 31, 2013. The financial swap was designed to hedge spot market purchases, which, along with ComEd s remaining energy procurement contracts, met its load service requirements. The terms of the financial swap contract required Generation to pay the around-the-clock market price for a portion of ComEd s electricity supply requirement, while ComEd paid a fixed price.

As the contract expired May 31, 2013, all realized impacts have been included in Generation s and ComEd s results of operations. In Exelon s consolidated financial statements, all financial statement effects of the financial swap recorded by Generation and ComEd are eliminated.

In addition, the physical contracts that Generation has entered into with ComEd and that ComEd has entered into with Generation and other suppliers as part of the ComEd power procurement process, which are further discussed in Note 3 Regulatory Matters of the Exelon 2012 Form 10-K qualify and are accounted for under the NPNS exception. Based on the Illinois Settlement Legislation and ICC-approved procurement methodologies permitting ComEd to recover its electricity procurement costs from retail customers with no mark-up, ComEd s price risk related to power procurement is limited.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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 associate RECs were reduced in the first quarter of 2013. These contracts are designed to lock in a portion of the long-term commodity price risk resulting from the renewable energy resource procurement requirements in the Illinois Settlement Legislation. ComEd has not elected hedge accounting for these derivative financial instruments. ComEd records the fair value of the swap contracts on its balance sheet. Because ComEd receives full cost recovery for energy procurement and related costs from retail customers, the change in fair value each period is recorded by ComEd as a regulatory asset or liability. See Note 5 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 5 Regulatory Matters. Based on Pennsylvania legislation and the DSP Programs permitting PECO to recover its electric supply procurement costs from retail customers with no mark-up, PECO s price risk related to electric supply procurement is limited. PECO locked in fixed prices for a significant portion of its commodity price risk through full requirements contracts and block contracts. PECO has certain full requirements contracts and block contracts that are considered derivatives and qualify for the NPNS scope exception under current derivative authoritative guidance.

PECO s natural gas procurement policy is designed to achieve a reasonable balance of long-term and short-term gas purchases under different pricing approaches in order to achieve system supply reliability at the least cost. PECO s reliability strategy is two-fold. First, PECO must assure that there is sufficient transportation capacity to satisfy delivery requirements. Second, PECO must ensure that a firm source of supply exists to utilize the capacity resources. All of PECO s natural gas supply and asset management agreements that are derivatives either qualify for the NPNS scope exception and have been designated as such, or have no mark-to-market balances because the derivatives are index priced. Additionally, in accordance with the 2013 PAPUC PGC settlement and to reduce the exposure of PECO and its customers to natural gas price volatility, PECO has continued its program to purchase natural gas for both winter and summer supplies using a layered approach of locking-in prices ahead of each season with long-term gas purchase agreements (those with primary terms of at least twelve months). Under the terms of the 2013 PGC settlement, PECO is required to lock in (i.e., economically hedge) the price of a minimum volume of its long-term gas commodity purchases. PECO s gas-hedging program is designed to cover about 30% of planned natural gas purchases in support of projected firm sales. The hedging program for natural gas procurement has no direct impact on PECO s financial position or results of operations as natural gas costs are fully recovered from customers under the PGC.

BGE has contracts to procure SOS electric supply that are executed through a competitive procurement process approved by the MDPSC. The SOS rates charged recover BGE's wholesale power supply costs and include an administrative fee. The administrative fee includes an incremental cost component and a shareholder return component for commercial and industrial rate classes. BGE s price risk related to electric supply procurement is limited. BGE locks in fixed prices for all of its SOS requirements through full requirements contracts. Certain of BGE s full requirements contracts, which are considered derivatives, qualify for the NPNS scope exception under current derivative authoritative guidance. Other BGE full requirements contracts are not derivatives.

BGE provides natural gas to its customers under a MBR mechanism approved by the MDPSC. Under this mechanism, BGE s actual cost of gas is compared to a market index (a measure of the market price of gas in a given period). The difference between BGE s actual cost and the market index is shared equally between shareholders and customers. BGE must also secure fixed price contracts for at least 10%, but not more than 20%, of forecasted system supply requirements for flowing (i.e., non-storage) gas for the November through March period. These fixed-price contracts are not subject to sharing under the MBR mechanism. BGE also ensures it has sufficient pipeline transportation capacity to meet customer requirements. All of BGE s natural gas supply and asset management agreements qualify for the NPNS exception and result in physical delivery.

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

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 2,499 GWhs and 6,066 GWhs for the three and nine months ended September 30, 2013, respectively, and 4,352 GWhs and 9,981 GWhs for the three and nine months ended September 30, 2012, respectively, 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 (Exelon, Generation, ComEd, PECO and BGE)

The Registrants use a combination of fixed-rate and variable-rate debt to manage interest rate exposure. The Registrants may also utilize fixed-to-floating interest rate swaps, which are typically designated as fair value hedges, as a means to manage their interest rate exposure. In addition, the Registrants may utilize interest rate derivatives to lock in rate levels in anticipation of future financings, which are typically designated as cash flow hedges. These strategies are employed to manage interest rate risks. At September 30, 2013, Exelon had $1,250 million of notional amounts of fixed-to-floating hedges outstanding and $213 million of notional amounts of floating-to-fixed hedges outstanding. Assuming the fair value and cash flow interest rate hedges are 100% effective, a hypothetical 50 bps increase in the interest rates associated with unhedged variable-rate debt (excluding Commercial Paper) and fixed-to-floating swaps would result in approximately a $1 million decrease in Exelon Consolidated pre-tax income for the nine months ended September 30, 2013. To manage foreign exchange rate exposure associated with international energy purchases in currencies other than U.S. dollars, Generation utilizes foreign currency derivatives, which are typically designated as economic hedges. Below is a summary of the interest rate and foreign currency hedges as of September 30, 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	$ 18	$ (19)	$ 2	$	$ 2
Mark-to-market derivative assets (Noncurrent Assets)	27	5	17	(16)	33	13	46
Total mark-to-market derivative assets	$ 27	$ 8	$ 35	$ (35)	$ 35	$ 13	$ 48
Mark-to-market derivative liabilities (Current Liabilities)	$ (1)	$ (1)	$ (19)	$ 19	$ (2)	$	$ (2)
Mark-to-market derivative liabilities (Noncurrent liabilities)	(14)		(16)	16	(14)		(14)
Total mark-to-market derivative liabilities	$ (15)	$ (1)	$ (35)	$ 35	$ (16)	$	$ (16)
Total mark-to-market derivative net assets (liabilities)	$ 12	$ 7	$	$	$ 19	$ 13	$ 32

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

(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 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.

The following table provides a summary of the interest rate hedge balances recorded by the Registrants as of December 31, 2012:

	Generation					Other	Exelon
Description	**Derivatives Designated as Hedging Instruments**	**Economic Hedges**	**Proprietary Trading (a)**	**Collateral and Netting (b)**	**Subtotal**	**Derivatives Designated as Hedging Instruments**	**Total**
Mark-to-market derivative assets (Current Assets)	$	$ 3	$ 20	$ (19)	$ 4	$	$ 4
Mark-to-market derivative assets (Noncurrent Assets)	38	8	32	(32)	46	13	59
Total mark-to-market derivative assets	$ 38	$ 11	$ 52	$ (51)	$ 50	$ 13	$ 63
Mark-to-market derivative liabilities (Current Liabilities)	$ (1)	$ (1)	$ (19)	$ 19	$ (2)	$	$ (2)
Mark-to-market derivative liabilities (Noncurrent liabilities)	(31)		(32)	32	(31)		(31)
Total mark-to-market derivative liabilities	(32)	(1)	(51)	51	(33)		(33)
Total mark-to-market derivative net assets (liabilities)	$ 6	$ 10	$ 1	$	$ 17	$ 13	$ 30

(a) Generation enters into interest rate derivative contracts to economically hedge risk associated with the interest rate component of commodity positions. The characterization of the interest rate derivative contracts between the proprietary trading activity in the above table is driven by the corresponding characterization of the underlying commodity position that gives rise to the interest rate exposure. Generation does not utilize 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:

Three Months Ended September 30, 2013				**Nine Months Ended September 30, 2013**			
Gain (Loss) on Swaps		**Gain (Loss) on Borrowings**		**Gain (Loss) on Swaps**		**Gain (Loss) on Borrowings**	
Generation(a)	**Exelon**	**Generation**	**Exelon**	**Generation(a)**	**Exelon**	**Generation**	**Exelon**
$(4)	$ 4	$ (1)	$ (5)	$ (13)	$ 1	$	$ (2)

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Three Months Ended September 30, 2012				Nine Months Ended September 30, 2012			
Gain (Loss) on Swaps		Gain (Loss) on Borrowings		Gain (Loss) on Swaps		Gain (Loss) on Borrowings	
Generation	Exelon	Generation	Exelon	Generation	Exelon	Generation	Exelon
$(1)	$	$ (3)	$	$ (3)	$ (2)	$ (6)	$ 2

(a) For the three and nine months ended September 30, 2013, the loss on Generation swaps included $4 million and $12 million, respectively, realized in earnings, with an immaterial amount excluded from hedge effectiveness testing.

During the third quarter of 2013, Exelon entered into $450 million of notional amounts of fixed-to-floating fair value hedges related to interest rate swaps, which expire in 2020. At September 30, 2013, Exelon and Generation had total outstanding fixed-to-floating fair value hedges related to interest rate swaps of $1,100 million and $550 million, with unrealized gains of $40 million and $27 million, respectively. At December 31, 2012, Exelon and Generation had outstanding fixed-to-floating fair value hedges related to interest rate swaps of $650 million and $550 million that expire in 2015, with unrealized gains of $49 million and $38 million, respectively. During the nine months ended September 30, 2013 and 2012, the impact on the results of operations as a result of ineffectiveness from fair value hedges was a $1 million gain and immaterial, respectively.

Cash Flow Hedges. In anticipation of the Continental Wind, LLC non-recourse project financing that was completed on September 30, 2013, Exelon entered into forward starting interest rate swaps that were designated as cash flow hedges to hedge the change in benchmark interest rates. Upon settlement of the swaps, a $26 million effective gain in OCI was deferred and will be amortized into interest expense over the life of the debt. See Note 11 Debt and Credit Agreements for additional information on the project financing.

In connection with the DOE guaranteed loan for the Antelope Valley acquisition, as discussed in Note 11 Debt and Credit Agreements, Generation entered into a floating-to-fixed forward starting interest rate swap with a notional amount of $485 million and a mandatory early termination date of April 5, 2014. The swap hedges approximately 75% of Generation s future interest rate exposure associated with the financing and was designated as a cash flow hedge. As such, the effective portion of the hedge is recorded in other comprehensive income within Generation s Consolidated Balance Sheets, with any ineffectiveness recorded in Generation s Consolidated Statements of Operations and Comprehensive Income. Net gains (or losses) from settlement of the hedges, to the extent effective, are amortized as an adjustment to the interest expense over the term of the DOE guaranteed loan.

Every time Generation draws down on the loan, an offsetting hedge (fixed-to-floating) is executed and a portion of the cash flow hedge, with a notional amount equal to the offsetting hedge, is de-designated and the related gains or losses going forward are reflected in earnings, which are largely offset by the losses or gains in the offsetting hedge.

Antelope Valley received its first loan advance on April 5, 2012, and a series of additional advances subsequently. Generation has entered into a series of fixed-to-floating interest rate swaps with an aggregated notional amount of $328 million, approximately 75% of the loan advance amount to offset portions of the original interest rate hedge, which are not designated as cash flow hedges. The remaining cash flow hedge has a notional amount of $156 million. At September 30, 2013, Generation s mark-to-market non-current derivative liability relating to the interest rate swaps in connection with the loan agreement to fund Antelope Valley was $13 million.

During the third quarter of 2011, a subsidiary of Constellation entered into floating-to-fixed interest rate swaps to manage a portion of the interest rate exposure for anticipated long-term borrowings to finance Sacramento PV Energy. The swaps have a total notional amount of $29 million as of September 30, 2013 and expire in 2027. After the closing of the merger with Constellation, the swaps were re-designated as cash flow hedges. At September 30, 2013, the subsidiary had a $2 million non-current derivative liability related to these swaps.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

During the third quarter of 2012, a subsidiary of Exelon Generation entered into a floating-to-fixed interest rate swap to manage a portion of the interest rate exposure of anticipated long-term borrowings to finance Constellation Solar Horizons. The swap has a notional amount of $28 million as of September 30, 2013 and expires in 2030. This swap is designated as a cash flow hedge. At September 30, 2013, the subsidiary had a $2 million non-current derivative asset related to the swap.

During the nine months ended September 30, 2013 and 2012, the impact on the results of operations as a result of ineffectiveness from cash flow hedges was immaterial.

Economic Hedges. At September 30, 2013, Generation had $134 million in notional amounts of interest rate derivative contracts to economically hedge risk associated with the interest rate component of commodity positions and $38 million in notional amounts of foreign currency exchange rate swaps that are marked-to-market to manage the exposure associated with international purchases of commodities in currencies other than U.S. dollars.

At September 30, 2013, Exelon and Generation had $150 million in notional amounts of fixed-to-floating interest rate swaps that are marked-to-market, with unrealized gains of $3 million. These swaps, which were acquired as part of the merger with Constellation, expire in 2014. During the nine months ended September 30, 2013 and the period from March 12 to September 30, 2012, the impact on the results of operations was immaterial.

Fair Value Measurement and Accounting for the Offsetting of Amounts Related to Certain Contracts (Exelon, Generation, ComEd, PECO and BGE)

Fair value accounting guidance and disclosures about offsetting assets and liabilities requires the fair value of derivative instruments to be shown in the Notes to the Consolidated Financial Statements on a gross basis, even when the derivative instruments are subject to legally enforceable master netting agreements and qualify for net presentation in the Consolidated Balance Sheet. A master netting agreement is an agreement between two counterparties that may have derivative and non-derivative contracts with each other providing for the net settlement of all referencing contracts via one payment stream, which takes place either as the contracts deliver, when collateral is requested or in the event of default. Generation s use of cash collateral is generally unrestricted unless Generation is downgraded below investment grade (i.e. to BB+ or Ba1). In the table below, Generation s energy related economic hedges and proprietary trading derivatives are shown gross and the impact of the netting of fair value balances with the same counterparty that are subject to legally enforceable master netting agreements, as well as netting of cash collateral, is aggregated in the collateral and netting column. As of September 30, 2013 and December 31, 2012, $5 million of cash collateral posted and $3 million of cash collateral received, respectively, was not offset against derivative positions because such collateral was not associated with any energy-related derivatives or as of the balance sheet date there were no positions to offset. Excluded from the tables below are economic hedges that qualify for the NPNS scope exception and other non-derivative contracts that are accounted for under the accrual method of accounting.

ComEd s use of cash collateral is generally unrestricted unless ComEd is downgraded below investment grade (i.e. to BB+ or Ba1).

Cash collateral held by PECO and BGE must be deposited in a non affiliate major U.S. commercial bank or foreign bank with a U.S. branch office that meet certain qualifications.

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 September 30, 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)	$ 2,244	$ 1,577	$ (3,093)	$ 728	$	$ 728
Mark-to-market derivative assets (noncurrent assets)	1,540	447	(1,254)	733		733
Total mark-to-market derivative assets	$ 3,784	$ 2,024	$ (4,347)	$ 1,461	$	$ 1,461
Mark-to-market derivative liabilities (current liabilities)	$ (1,812)	$ (1,538)	$ 3,242	$ (108)	$ (16)	$ (124)
Mark-to-market derivative liabilities (noncurrent liabilities)	(911)	(438)	1,251	(98)	(106)	(204)
Total mark-to-market derivative liabilities	$ (2,723)	$ (1,976)	$ 4,493	$ (206)	$ (122)	$ (328)
Total mark-to-market derivative net assets (liabilities)	$ 1,061	$ 48	$ 146	$ 1,255	$ (122)	$ 1,133

(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 $86 million and $8 million, respectively, and current and noncurrent liabilities are shown net of collateral of $(235) million and $(5) million, respectively. The total cash collateral posted, net of cash collateral received and offset against mark-to-market assets and liabilities was $146 million at September 30, 2013.

(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, 2012:

	Generation				ComEd		Exelon
Derivatives	**Economic Hedges(a)**	**Proprietary Trading**	**Collateral and Netting(b)**	**Subtotal (c)**	**Economic Hedges (a)(d)**	**Intercompany Eliminations (a)**	**Total Derivatives**
Mark-to-market derivative assets (current assets)	$ 2,883	$ 2,469	$ (4,418)	$ 934	$	$	$ 934
Mark-to-market derivative assets with affiliate (current assets)	226			226		(226)	
Mark-to-market derivative assets (noncurrent assets)	1,792	724	(1,638)	878			878
Mark-to-market							
Total mark-to-market derivative assets	$ 4,901	$ 3,193	$ (6,056)	$ 2,038	$	$ (226)	$ 1,812
Mark-to-market derivative liabilities (current liabilities)	$ (2,419)	$ (2,432)	$ 4,519	$ (332)	$ (18)	$	$ (350)
Mark-to-market derivative liability with affiliate (current liabilities)					(226)	226	
Mark-to-market derivative liabilities (noncurrent liabilities)	(1,080)	(689)	1,568	(201)	(49)		(250)
Mark-to-market							
Total mark-to-market derivative liabilities	$ (3,499)	$ (3,121)	$ 6,087	$ (533)	$ (293)	$ 226	$ (600)
Total mark-to-market derivative net assets (liabilities)	$ 1,402	$ 72	$ 31	$ 1,505	$ (293)	$	$ 1,212

(a) Includes current and noncurrent assets for Generation and current and noncurrent liabilities for ComEd of $226 million related to the fair value of the five-year financial swap contract between Generation and ComEd, as described above. For Generation excludes $28 million of noncurrent liability relating to an interest rate swap in connection with a loan agreement to fund Antelope Valley as discussed above.

(b) Exelon and Generation net all available amounts allowed under the derivative accounting guidance on the balance sheet. These amounts include unrealized derivative transactions with the same counterparty under legally enforceable master netting agreements and cash collateral. In some cases Exelon and Generation may have other offsetting exposures, subject to a master netting or similar agreement, such as trade receivables and payables, transactions that do not qualify as derivatives, and letters of credit. These are not reflected in the table above.

(c) Current and noncurrent assets are shown net of collateral of $113 million and $201 million, respectively, and current and noncurrent liabilities are shown net of collateral of $ (214) million and $ (131) million, respectively. The total cash collateral received, net of cash collateral posted and offset against mark-to-market assets and liabilities was $31 million at December 31, 2012.

(d) Includes current and noncurrent liabilities relating to floating-to-fixed energy swap contracts with unaffiliated suppliers.

Cash Flow Hedges (Exelon, Generation and ComEd). As discussed previously, effective prior to the merger with Constellation, Generation de-designated all of its cash flow hedges relating to commodity price risk. Because the underlying forecasted transactions remain at least reasonably possible, the fair value of the effective portion of these cash flow hedges was frozen in accumulated OCI and is reclassified to results of operations when the forecasted purchase or sale of the energy commodity occurs, or becomes probable of not occurring. Generation began recording prospective changes in the fair value of these instruments through current earnings

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

from the date of de-designation. Approximately $271 million of these net pre-tax unrealized gains within accumulated OCI are expected to be reclassified from accumulated OCI during the next twelve months by Generation. Generation expects the settlement of the majority of its cash flow hedges will occur during 2013 through 2014.

Exelon discontinues hedge accounting prospectively when it determines that the derivative is no longer effective in offsetting changes in the cash flows of a hedged item or when it is no longer probable that the forecasted transaction will occur. For the three months ended September 30, 2013 and 2012, amounts reclassified into earnings as a result of the discontinuance of cash flow hedges were immaterial.

The tables below provide the activity of accumulated OCI related to cash flow hedges for the three and nine months ended September 30, 2013 and 2012, containing information about the changes in the fair value of cash flow hedges and the reclassification from accumulated OCI into results of operations. The amounts reclassified from accumulated OCI, when combined with the impacts of the actual physical power sales, result in the ultimate recognition of net revenues at the contracted price.

		Total Cash Flow Hedge OCI Activity, Net of Income Tax	
		Generation	Exelon
Three Months Ended September 30, 2013	**Income Statement Location**	**Energy-Related Hedges**	**Total Cash Flow Hedges**
Accumulated OCI derivative gain at June 30, 2013		$ 255(a)	$ 245
Effective portion of changes in fair value			2(b)
Reclassifications from accumulated OCI to net income	Operating Revenues	(51)	(48)
Accumulated OCI derivative gain at September 30, 2013		$ 204(a)	$ 199

(a) Excludes $11 million of losses, net of taxes, related to interest rate swaps and treasury rate locks as of September 30, 2013 and June 30, 2013.
(b) Includes $2 million of gains, net of taxes, related to the effective portion of changes in fair value of interest rate swaps and treasury rate locks.

		Total Cash Flow Hedge OCI Activity, Net of Income Tax	
		Generation	Exelon
Nine Months Ended September 30, 2013	**Income Statement Location**	**Energy-Related Hedges**	**Total Cash Flow Hedges**
Accumulated OCI derivative gain at December 31, 2012		$ 532(a)(c)	$ 368
Effective portion of changes in fair value			25(d)
Reclassifications from accumulated OCI to net income	Operating Revenues	(328)(b)	(194)
Accumulated OCI derivative gain at September 30, 2013		$ 204(c)	$ 199

(a)

Includes $133 million of gains, net of taxes, related to the fair value of the five-year financial swap contract with ComEd, as of December 31, 2012.

(b) Includes $133 million of losses, net of taxes, reclassified from accumulated OCI to recognize gains in net income related to the settlements of the five-year financial swap contract with ComEd.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

(c) Excludes $11 million of losses and $20 million of losses, net of taxes, related to interest rate swaps and treasury locks as of September 30, 2013 and December 31, 2012, respectively.
(d) Includes $25 million of losses, net of taxes, related to the effective portion of changes in fair value of interest rate swaps and treasury rate locks.

		Total Cash Flow Hedge OCI Activity, Net of Income Tax	
		Generation	**Exelon**
Three Months Ended September 30, 2012	**Income Statement Location**	**Energy-Related Hedges**	**Total Cash Flow Hedges**
Accumulated OCI derivative gain at June 30, 2012		$ 923(a)(c)	$ 547
Effective portion of changes in fair value		(e)	(d)
Reclassifications from accumulated OCI to net income	Operating Revenues	(171)(b)	(88)
Accumulated OCI derivative gain at September 30, 2012		$ 752(a)(c)	$ 459

(a) Includes $232 million and $315 million of gains, net of taxes, related to the fair value of the five-year financial swap contract with ComEd as of September 30, 2012 and June 30, 2012, respectively.
(b) Includes a $83 million of losses, net of taxes, reclassified from accumulated OCI to recognize gains in net income related to the settlements of the five-year financial swap contract with ComEd.
(c) Excludes $22 million of losses and $22 million of gains, net of taxes, related to interest rate swaps and treasury rate locks for the three months ended September 30, 2012 and June 30, 2012 respectively.
(d) Includes $0 million of losses, net of taxes, at Generation related to the effective portion of changes in fair value of interest rate swaps and treasury rate locks.
(e) Due to de-designation of all commodity cash flow positions prior to the merger date, there are no changes in fair value.

		Total Cash Flow Hedge OCI Activity, Net of Income Tax	
		Generation	**Exelon**
Nine Months Ended September 30, 2012	**Income Statement Location**	**Energy-Related Hedges**	**Total Cash Flow Hedges**
Accumulated OCI derivative gain at December 31, 2011		$ 925(a)(c)	$ 488
Effective portion of changes in fair value		432(e)	301(d)
Reclassifications from accumulated OCI to net income	Operating Revenues	(608)(b)	(333)
Ineffective portion recognized in income	Operating Revenues	3	3
Accumulated OCI derivative gain at September 30, 2012		$ 752(a)(c)	$ 459

(a) Includes $232 million and $420 million of gains, net of taxes, related to the fair value of the five-year financial swap contract with ComEd, as of September 30, 2012 and December 31, 2011.
(b) Includes $276 million of losses, net of taxes, reclassified from accumulated OCI to recognize gains in net income related to the settlements of the five-year financial swap contract with ComEd.
(c)

Excludes $22 million of losses and $10 million of losses, net of taxes, related to interest rate swaps and treasury rate locks for the nine months ended September 30, 2012 and year ended December 31, 2011, respectively.

(d) Includes $12 million of losses, net of taxes, related to the effective portion of changes in fair value of interest rate swaps and treasury rate locks.

(e) Includes $88 million of gains, net of taxes, related to the effective portion of changes in fair value of the five-year financial swap contract with ComEd through the date of de-designation prior to the merger.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

During the three and nine months ended September 30, 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 $84 million and a $543 million pre-tax gain and $283 million and $1,005 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 nine months ended September 30, 2012.

Exelon s former energy-related cash flow hedge activity impact to pre-tax earnings based on the reclassification adjustment from accumulated OCI to earnings was a $84 million and $324 million pre-tax gain for the three and nine months ended September 30, 2013, respectively, and a $145 million and $548 million pre-tax gain for the three and nine months ended September 30, 2012, respectively. Changes in cash flow hedge ineffectiveness was losses of $5 million for the nine months ended September 30, 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 merger date.

Economic Hedges (Exelon and Generation). These instruments represent hedges that economically mitigate exposure to fluctuations in commodity prices and include financial options, futures, swaps, and physical forward sales and purchases but for which the fair value or cash flow hedge elections were not made. For the three and nine months ended September 30, 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 at Exelon and Generation in the Consolidated Statements of Operations and Comprehensive Income and are included in Net fair value changes related to derivatives in Exelon s and Generation s Consolidated Statements of Cash Flows. In the tables below, Change in fair value represents the change in fair value of the derivative contracts held at the reporting date. The Reclassification to realized at settlement represents the recognized change in fair value that was reclassified to realized due to settlement of the derivative during the period.

Three Months Ended September 30, 2013	Generation Operating Revenues	Generation Purchased Power and Fuel	Generation Total	Intercompany Eliminations Operating Revenues(a)	Exelon Total
Change in fair value	$ 175	$ 5	$ 180	$	$ 180
Reclassification to realized at settlement	41	25	66		66
Net mark-to-market gains	$ 216	$ 30	$ 246	$	$ 246

Nine Months Ended September 30, 2013	Generation Operating Revenues	Generation Purchased Power and Fuel	Generation Total	Intercompany Eliminations Operating Revenues(a)	Exelon Total
Change in fair value	$ 149	$ 74	$ 223	$ (6)	$ 217
Reclassification to realized at settlement	(15)	63	48	13	61
Net mark-to-market gains	$ 134	$ 137	$ 271	$ 7	$ 278

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

		Generation		Intercompany Eliminations	Exelon
Three Months Ended September 30, 2012	**Operating Revenues**	**Purchased Power and Fuel**	**Total**	**Operating Revenues(a)**	**Total**
Change in fair value	$ (255)	$ 129	$ (126)	$ 35	$ (91)
Reclassification to realized at settlement	20	122	142	(19)	123
Net mark-to-market gains (losses)	$ (235)	$ 251	$ 16	$ 16	$ 32

		Generation		Intercompany Eliminations	Exelon
Nine Months Ended September 30, 2012	**Operating Revenues**	**Purchased Power and Fuel**	**Total**	**Operating Revenues(a)**	**Total**
Change in fair value	$ (85)	$ 121	$ 36	$ 62	$ 98
Reclassification to realized at settlement	(81)	326	245	(29)	216
Net mark-to-market gains (losses)	$ (166)	$ 447	$ 281	$ 33	$ 314

(a) Prior to the merger, the five-year financial swap contract between Generation and ComEd was de-designated. As a result, all prospective changes in fair value are recorded to operating revenues and eliminated in consolidation.

Proprietary Trading Activities (Exelon and Generation). For the three and nine months ended September 30, 2013 and 2012, Exelon and Generation recognized the following net unrealized mark-to-market gains (losses), net realized mark-to-market gains (losses) and total net mark-to-market gains (losses) (before income taxes) relating to mark-to-market activity on derivative instruments entered into for proprietary trading purposes. Gains and losses associated with proprietary trading are reported as operating revenue in Exelon s and Generation s Consolidated Statements of Operations and Comprehensive Income and are included in Net fair value changes related to derivatives in Exelon s and Generation s Consolidated Statements of Cash Flows. In the tables below, Change in fair value represents the change in fair value of the derivative contracts held at the reporting date. The Reclassification to realized at settlement represents the recognized change in fair value that was reclassified to realized due to settlement of the derivative during the period.

	Location on Income Statement	Three Months Ended September 30, 2013	Three Months Ended September 30, 2012	Nine Months Ended September 30, 2013	Nine Months Ended September 30, 2012
Change in fair value	Operating Revenue	$	$ (2)	$ 1	$ 12
Reclassification to realized at settlement	Operating Revenue	(40)	25	(36)	57
Net mark-to-market gains (losses)	Operating Revenue	$ (40)	$ 23	$ (35)	$ 69

Credit Risk (Exelon, Generation, ComEd, PECO and BGE)

The Registrants would be exposed to credit-related losses in the event of non-performance by counterparties that enter into derivative instruments. The credit exposure of derivative contracts, before collateral, is represented by the fair value of contracts at the reporting date. For energy-related derivative instruments, Generation enters into enabling agreements that allow for payment netting with its counterparties, which reduces Generation s exposure to counterparty risk by providing for the offset of amounts payable to the counterparty against amounts receivable from the counterparty. Typically, each enabling agreement is for a specific commodity and so, with respect to each individual counterparty, netting is limited to transactions involving that specific commodity product, except where master netting agreements exist with a counterparty that allow for cross product netting. In addition to payment netting language in the enabling agreement, Generation s credit department establishes

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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 September 30, 2013. The tables further delineate that exposure by credit rating of the counterparties and provide guidance on the concentration of credit risk to individual counterparties. The figures in the tables below do not include credit risk exposure from uranium procurement contracts or exposure through RTOs, ISOs, NYMEX, ICE and Nodal commodity exchanges, further discussed in ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK. Additionally, the figures in the tables below do not include exposures with affiliates, including net receivables with ComEd, PECO and BGE of $33 million, $30 million and $39 million, respectively.

Rating as of September 30, 2013	Total Exposure Before Credit Collateral	Credit Collateral	Net Exposure	Number of Counterparties Greater than 10% of Net Exposure	Net Exposure of Counterparties Greater than 10% of Net Exposure
Investment grade	$ 1,767	$ 191	$ 1,576	1	$ 478
Non-investment grade	16	9	7		
No external ratings					
Internally rated investment grade	472	6	466	1	238
Internally rated non-investment grade	18	1	17		
Total	$ 2,273	$ 207	$ 2,066	2	$ 716

Net Credit Exposure by Type of Counterparty	As of September 30, 2013
Investor-owned utilities, marketers and power producers	$ 743
Energy cooperatives and municipalities	916
Financial institutions	355
Other	52
Total	$ 2,066

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 September 30, 2013, ComEd s credit exposure to suppliers was immaterial.

ComEd is permitted to recover its costs of procuring energy through the Illinois Settlement Legislation. ComEd s counterparty credit risk is mitigated by its ability to recover realized energy costs through customer rates. See Note 5 Regulatory Matters for additional information.

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 electric supply procurement contracts, which define a supplier s performance assurance requirements, allow a supplier to meet its credit requirements with a certain amount of unsecured credit. The amount of unsecured credit is determined based on the supplier s lowest credit rating from the major credit rating agencies and the supplier s tangible net worth. The credit position is based on the initial market price, which is the forward price of energy on the day a transaction is executed, compared to the current forward price curve for energy. To the extent that the forward price curve for energy exceeds the initial market price, the supplier is required to post collateral to the extent the credit exposure is greater than the supplier s unsecured credit limit. As of September 30, 2013, PECO had no net credit exposure with suppliers.

PECO is permitted to recover its costs of procuring electric supply through its PAPUC-approved DSP Program. PECO s counterparty credit risk is mitigated by its ability to recover realized energy costs through customer rates. See Note 5 Regulatory Matters for further 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 September 30, 2013, PECO had credit exposure of $9 million under its natural gas supply and asset management agreements with investment grade suppliers.

BGE is permitted to recover its costs of procuring energy through the MDPSC-approved procurement tariffs. BGE s counterparty credit risk is mitigated by its ability to recover realized energy costs through customer rates. See Note 5 Regulatory Matters for further 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 seller s credit exposure is calculated each business day. As of September 30, 2013, 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 September 30, 2013, BGE had credit exposure of $1 million related to off-system sales which is mitigated by parental guarantees, letters of credit, or right to offset clauses within other contracts with those third party suppliers.

Collateral and Contingent-Related Features (Exelon, Generation, ComEd, PECO and BGE)

As part of the normal course of business, Generation routinely enters into physical or financially settled contracts for the purchase and sale of electric capacity, energy, fuels, emissions allowances and other energy-related products. Certain of Generation s derivative instruments contain provisions that require Generation to post collateral. Generation also enters into commodity transactions on exchanges (i.e., NYMEX, ICE). The exchanges act as the counterparty to each trade. Transactions on the exchanges must adhere to comprehensive

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

collateral and margining requirements. This collateral may be posted in the form of cash or credit support with thresholds contingent upon Generation s credit rating from each of the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty. These credit-risk-related contingent features stipulate that if Generation were to be downgraded or lose its investment grade credit rating (based on its senior unsecured debt rating), it would be required to provide additional collateral. This incremental collateral requirement allows for the offsetting of derivative instruments that are assets with the same counterparty, where the contractual right of offset exists under applicable master netting agreements. In the absence of expressly agreed-to provisions that specify the collateral that must be provided, collateral requested will be a function of the facts and circumstances of the situation at the time of the demand. In this case, Generation believes an amount of several months of future payments (i.e., capacity payments) rather than a calculation of fair value is the best estimate for the contingent collateral obligation, which has been factored into the disclosure below.

The aggregate fair value of all derivative instruments with credit-risk related contingent features in a liability position that are not fully collateralized (excluding transactions on the exchanges that are fully collateralized) is detailed in the table below:

Credit-Risk Related Contingent Feature		**September 30, 2013**
Gross Fair Value of Derivative Contracts Containing this Feature(a)	**Offsetting Fair Value of In-the-Money Contracts Under Master Netting Arrangements(b)**	**Net Fair Value of Derivative Contracts Containing This Feature(c)**
$ (961)	$790	$ (171)

Credit-Risk Related Contingent Feature		**December 31, 2012**
Gross Fair Value of Derivative Contracts Containing this Feature(a)	**Offsetting Fair Value of In-the-Money Contracts Under Master Netting Arrangements(b)**	**Net Fair Value of Derivative Contracts Containing This Feature(c)**
$ (1,849)	$1,426	$ (423)

(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 $353 million and letters of credit posted of $326 million and cash collateral held of $202 million and letters of credit held of $32 million as of September 30, 2013 and cash collateral posted of $527 million and letters of credit posted of $563 million and cash collateral held of $499 million and letters of credit held of $45 million at December 31, 2012 for counterparties with derivative positions. In the event of a credit downgrade below investment grade (i.e., to BB+ or Ba1), Generation could be required to post additional collateral of $1.8 billion as of September 30, 2013 and $2.0 billion as of December 31, 2012. These amounts represent the potential additional collateral required after giving consideration to offsetting derivative and non-derivative positions under master netting agreements.

Generation s and Exelon s interest rate swaps contain provisions that, in the event of a merger, if Generation s debt ratings were to materially weaken, it would be in violation of these provisions, resulting in the ability of the counterparty to terminate the agreement prior to maturity. Collateralization would not be required under any circumstance. Termination of the agreement could result in a settlement payment by Exelon or the counterparty on any interest rate swap in a net liability position. The settlement amount would be equal to the fair value of the swap on the termination date. As of September 30, 2013, Generation s and Exelon s swaps were in an asset position, with a fair value of $19 million and $32 million, respectively.

See Note 21 Segment Information of the Exelon 2012 Form 10-K for further information regarding the letters of credit supporting the cash collateral.

Generation entered into SFCs 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 September 30, 2013, ComEd held immaterial amounts of collateral from suppliers in association with energy procurement contracts. Under the terms of ComEd s annual renewable energy contracts, collateral postings are required to cover a fixed value for RECs only. In addition, under the terms of ComEd s long-term renewable energy contracts, collateral postings are required from suppliers for both RECs and energy. The REC portion is a fixed value and the energy portion is one-sided from suppliers should the forward market prices exceed contract prices. As of September 30, 2013, ComEd held approximately $19 million in the form of cash and letters of credit as margin for both the annual and long-term REC obligations. See Note 3 Regulatory Matters of the Exelon 2012 Form 10-K for further 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 September 30, 2013, PECO was not required to post collateral for any of these agreements. If PECO lost its investment grade credit rating as of September 30, 2013, PECO could have been required to post approximately $30 million of collateral to its counterparties.

PECO s supplier master agreements that govern the terms of its DSP Program contracts do not contain provisions that would require PECO to post collateral.

BGE s full requirements wholesale power agreements that govern the terms of its electric supply procurement contracts do not contain provisions that would require BGE to post collateral.

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 September 30, 2013, BGE was not required to post collateral for any of these agreements. If BGE lost its investment grade credit rating as of September 30, 2013, BGE could have been required to post approximately $41 million of collateral to its counterparties.

11. Debt and Credit Agreements (Exelon, Generation, ComEd, PECO and BGE)

Short-Term Borrowings

Exelon, ComEd and BGE meet their short-term liquidity requirements primarily through the issuance of commercial paper. Generation and PECO meet their short-term liquidity requirements primarily through the issuance of commercial paper and borrowings from the intercompany money pool.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

The Registrants had the following amounts of commercial paper borrowings outstanding as of September 30, 2013 and December 31, 2012:

Commercial Paper Borrowings	September 30, 2013	December 31, 2012
Exelon Corporate	$	$
Generation		
ComEd	153	
PECO		
BGE	40	

Credit Facilities

Exelon had bank lines of credit under committed credit facilities at September 30, 2013 for short-term financial needs, as follows:

Type of Credit Facility	Amount(a) (In billions)	Expiration Dates	Capacity Type
Exelon Corporate			
Syndicated Revolver	$ 0.5	August 2018	Letters of credit and cash
Generation			
Syndicated Revolver	5.3	August 2018	Letters of credit and cash
Bilateral	0.3	December 2015 and March 2016	Letters of credit and cash
Bilateral	0.1	January 2015	Letters of credit
ComEd			
Syndicated Revolver	1.0	March 2018	Letters of credit and cash
PECO			
Syndicated Revolver	0.6	August 2018	Letters of credit and cash
BGE			
Syndicated Revolver	0.6	August 2018	Letters of credit and cash
Total	$ 8.4		

(a) Excludes additional credit facility agreements for Generation, ComEd, PECO and BGE with aggregate commitments of $50 million, $34 million, $34 million and $5 million, respectively, arranged with minority and community banks located primarily within ComEd s, PECO s and BGE s service territories. These facilities expire on October 18, 2014 and are solely utilized to issue letters of credit. As of September 30, 2013, letters of credit issued under these agreements for Generation, ComEd, PECO and BGE totaled $24 million, $26 million, $21 million and $1 million, respectively.

As of September 30, 2013, there were no borrowings under the Registrants credit facilities.

On January 23, 2013, Generation entered into a two year $75 million bilateral letter of credit facility with a bank. The credit agreement expires in January 2015. This facility will solely be utilized by Generation to issue letters of credit.

On March 14, 2013, ComEd extended its unsecured revolving credit facility with aggregate bank commitments of $1.0 billion. Under this facility, ComEd may issue letters of credit in the aggregate amount of up to $500 million. The credit agreement expires on March 28, 2018, and ComEd may request another one-year extension of that term. The credit facility also allows ComEd to request increases in the aggregate commitments of up to an additional $500 million. Any such extension or increases are subject to the approval of the lenders party to the credit agreement in their sole discretion. Costs incurred to extend the facility for ComEd were not material.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

On August 10, 2013, Exelon Corporate, Generation, PECO and BGE amended and extended their respective unsecured syndicated revolving credit facilities, with aggregate bank commitments of $500 million, $5.3 billion, $600 million and $600 million, respectively. The new covenants are substantially consistent with existing covenants. Costs incurred to amend and extend the facilities for Exelon Corporate, Generation, PECO and BGE were not material.

Effective August 10, 2013, Exelon and ComEd entered into amendments to each of their respective revolving credit facilities (the Amendments). The Amendments relate to the IRS s challenge to the position taken by Exelon on its 1999 federal income tax return with respect to the sale of ComEd s fossil generating assets in a like-kind exchange tax position. The Amendments are intended to exclude the non-cash impact of the like-kind exchange tax position from the calculation of the interest coverage ratio under each of Exelon and ComEd s respective credit facilities. See Note 12 Income Taxes for additional information.

Borrowings under Exelon Corporate s, Generation s, ComEd s, PECO s and BGE s credit agreements bear interest at a rate based upon either the prime rate or a LIBOR-based rate, plus an adder based upon the particular registrant s credit rating. Exelon Corporate, Generation, ComEd, PECO and BGE have adders of 27.5, 27.5, 27.5, 0.0 and 7.5 basis points for prime based borrowings and 127.5, 127.5, 127.5, 100.0 and 107.5 basis points for LIBOR-based borrowings. The maximum adders for prime rate borrowings and LIBOR-based rate borrowings are 65 basis points and 165 basis points, respectively. The credit agreements also require the borrower to pay a facility fee based upon the aggregate commitments under the agreement. The fee varies depending upon the respective credit ratings of the borrower.

On October 18, 2013, Generation, ComEd, PECO and BGE replaced their respective minority and community bank credit facility agreements in the amounts of $50 million, $34 million, $34 million and $5 million, respectively. These facilities, which expire in October 2014, are solely utilized to issue letters of credit.

Long-Term Debt

Issuance of Long-Term Debt

During the nine months ended September 30, 2013, the following long-term debt was issued:

Company	Type	Interest Rate	Maturity	Amount	Use of Proceeds
Generation	Upstream Gas Lending Agreement	2.210 - 2.440%	July 22, 2016	$ 5	Used to fund Upstream gas activities
Generation	DOE Project Financing	2.535 - 3.353%	January 5, 2037	$ 204	Funding for Antelope Valley Solar Development
Generation	Energy Efficiency Project Financing	4.400%	August 31, 2014	$ 9	Funding to install energy conservation measures in Beckley, West Virginia
Generation	Continental Wind Senior Secured Notes	6.000%	February 28, 2033	$ 613	Used for general corporate purposes
ComEd	First Mortgage Bonds	4.600%	August 15, 2043	$ 350	Used to repay outstanding commercial paper obligations and for general corporate purposes

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Company	Type	Interest Rate	Maturity	Amount	Use of Proceeds
PECO	First and Refunding Mortgage Bonds	1.200%	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	4.800%	October 15, 2043	$ 250	Used to pay at maturity first and refunding mortgage bonds due October 15, 2013 and other general corporate purposes
BGE	Senior Notes	3.350%	July 1, 2023	$ 300	Used to partially refinance Notes due July 1, 2013 and for general corporate purposes

During the nine months ended September 30, 2012, the following long-term debt was issued:

Company	Type	Interest Rate	Maturity	Amount	Use of Proceeds
Generation	Senior Notes	4.250%	June 15, 2022	$ 523	Used for general corporate purposes and issued in connection with the Exchange Offer
Generation	Senior Notes	5.600%	June 15, 2042	$ 788	Used for general corporate purposes and issued in connection with the Exchange Offer
Generation	CEU Credit Agreement	1.990%	June 16, 2016	$ 43	Used to fund upstream gas activities
Generation	DOE Project Financing	2.330 - 3.092%	January 5, 2037	$ 100	Funding for Antelope Valley Solar Development
Generation	Clean Horizons	2.500%	June 7, 2030	$ 38	Funding for Maryland solar development
PECO	First and Refunding Mortgage Bonds	2.375%	September 15, 2022	$ 350	Used to pay at maturity First Mortgage Bonds due October 1, 2012 and for general corporate purposes
BGE	Notes	2.800%	August 15, 2032	$ 250	Used to repay total outstanding commercial paper and for general corporate purposes

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Retirement of Current and Long-Term Debt

During the nine months ended September 30, 2013, the following long-term debt was retired:

Company	Type	Interest Rate	Maturity	Amount
Generation	Kennett Square Capital Lease	7.830%	September 20, 2020	$ 2
Generation	Solar Revolver	1.930 - 1.950%	July 7, 2014	$ 18
Generation	Clean Horizons	2.563%	September 7, 2030	$ 1
Generation(a)	Series A Junior Subordinated Debentures	8.625%	June 15, 2063	$ 450
ComEd	First Mortgage Bonds Series 92	7.625%	April 15, 2013	$ 125
ComEd	First Mortgage Bonds Series 94	7.500%	July 1, 2013	$ 127
BGE	Senior Notes	6.125%	July 1, 2013	$ 400
BGE	Rate Stabilization Bonds	5.720%	April 1, 2017	$ 33

(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.

On October 1, 2013, BGE retired $34 million aggregate principal of its 5.720% Rate Stabilization Bonds due April 1, 2017.

On October 15, 2013, PECO retired $300 million aggregate principal of its 5.600% First and Refunding Mortgage Bonds due October 15, 2013.

During the nine months ended September 30, 2012, the following long-term debt was retired:

Company	Type	Interest Rate	Maturity	Amount
ComEd	First Mortgage Bond Series 98	6.15%	March 15, 2012	$ 450
BGE	Rate Stabilization Bonds	5.68%	April 1, 2017	$ 31
BGE	Medium Term Notes	6.73 - 6.75%	June 15, 2012	$ 110
Generation	Kennett Square Capital Lease	7.83%	September 20, 2020	$ 2
Generation	Armstrong Co. tax-exempt	5.00%	December 1, 2042	$ 46
Generation	MEDCO Tax-Exempt Bonds	Various	April 1, 2024	$ 75
Generation	Solar Revolver	2.49%	July 7, 2014	$ 13
Generation	CEU Credit Agreement	2.27%	July 16, 2016	$ 3
Exelon	Senior Notes	7.60%	April 1, 2032	$ 442
Exelon	Medium Term Notes	7.30%	June 1, 2012	$ 2

Accounts Receivable Agreement

PECO was party to an agreement with a financial institution under which it transferred an undivided interest, adjusted daily, in its accounts receivable designated under the agreement in exchange for proceeds of $210 million, which was classified as a short-term note payable on Exelon s and PECO s Consolidated Balance Sheets as of December 31, 2012. The agreement terminated on August 30, 2013 and PECO paid down the outstanding principal of $210 million. The financial institution no longer has an undivided interest in the

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accounts receivable designated under the agreement. As of December 31, 2012, the financial institution s undivided interest in Exelon s and PECO s gross accounts receivable was equivalent to $289 million, which represented the financial institution s interest in PECO s eligible receivables as calculated under the terms of the agreement. The agreement required PECO to maintain eligible receivables at least equivalent to the financial institution s undivided interest.

Willis Tower Capital Lease

In the second quarter of 2013, ComEd entered into a 20-year capital lease for transmission distribution space at Willis Tower in Chicago, Illinois. ComEd recorded $8 million on its Consolidated Balance Sheets within property plant and equipment and long-term debt at the inception of the lease. ComEd will make lease payments of less than $1 million annually in 2013-2017 and approximately $7 million thereafter.

Non-Recourse Debt

The following are descriptions of activity that occurred for the nine months ended September 30, 2013 of certain indebtedness of Exelon s project subsidiaries. The indebtedness described below is specific to certain generating facilities pledged as collateral with a net book value of approximately $1.8 billion at September 30, 2013, and all associated project financing liabilities are non-recourse to Exelon and Generation.

Continental Wind

On September 30, 2013, Continental Wind, LLC (Continental Wind), an indirect subsidiary of Exelon and Generation, completed the issuance and sale of $613 million aggregate principal amount of Continental Wind s 6.00% senior secured notes due February 28, 2033. Continental Wind owns and operates a portfolio of wind farms in Idaho, Kansas, Michigan, Oregon, New Mexico and Texas with a total net capacity of 667 MW. The net proceeds were distributed to Generation for its general business purposes. In connection with this non-recourse project financing, Exelon terminated existing interest rate swaps with a total notional amount of $350 million during the third quarter of 2013, and realized a total gain of $26 million upon termination. The gain on the interest rate swaps was recorded within OCI and will reduce the effective interest rate over the life of the debt for Exelon. See Note 10 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 the credit support and security obligations of itself. As of September 30, 2013, the Continental Wind letter of credit facility had $90 million in letters of credit outstanding related to the project.

Antelope Valley Project Development Debt Agreement

The DOE Loan Programs Office issued a guarantee for up to $646 million for a non-recourse loan from the Federal Financing Bank to support the financing of the construction of the Antelope Valley facility. The project is expected to be completed the first half of 2014.

In addition, Generation has issued letters of credit to support its equity investment in the project. As of September 30, 2013, Generation has reduced the letters of credit outstanding related to the project to $327 million. The letters of credit balance is expected to decline over time as scheduled equity contributions for the project are made.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

12. Income Taxes (Exelon, Generation, ComEd, PECO and BGE)

The effective income tax rate from continuing operations varies from the U.S. Federal statutory rate principally due to the following:

For the Three Months Ended September 30, 2013	Exelon	Generation	ComEd	PECO	BGE
U.S. Federal statutory rate	35.0%	35.0%	35.0%	35.0%	35.0%
Increase (decrease) due to:					
State income taxes, net of Federal income tax benefit	3.0	2.6	5.4	(0.3)	5.6
Qualified nuclear decommissioning trust fund income	3.5	5.3			
Tax exempt income	(0.2)	(0.3)			
Health care reform legislation	0.1		0.4		0.2
Amortization of investment tax credit, net deferred taxes	(1.5)	(2.1)	(0.4)	(0.1)	(0.3)
Plant basis differences	(0.8)		(0.4)	(6.9)	0.1
Production tax credits and other credits	(2.2)	(3.3)			
Other	0.5	0.1	0.3	(0.1)	(0.2)
Effective income tax rate	37.4%	37.3%	40.3%	27.6%	40.4%

For the Nine Months Ended September 30, 2013	Exelon	Generation	ComEd	PECO	BGE
U.S. Federal statutory rate	35.0%	35.0%	35.0%	35.0%	35.0%
Increase (decrease) due to:					
State income taxes, net of Federal income tax benefit	5.3	1.8	5.2	1.9	5.6
Qualified nuclear decommissioning trust fund income	3.2	5.1			
Tax exempt income	(0.2)	(0.3)			
Health care reform legislation	0.1		0.9		0.2
Amortization of investment tax credit, net deferred taxes	(2.3)	(3.4)	(0.8)	(0.1)	(0.3)
Plant basis differences	(1.7)		(1.2)	(7.3)	(0.4)
Production tax credits and other credits	(2.4)	(3.9)			
Other	0.2	1.1	0.8		
Effective income tax rate	37.2%	35.4%	39.9%	29.5%	40.1%

For the Three Months Ended September 30, 2012	Exelon(a)	Generation(a)	ComEd	PECO	BGE(b)
U.S. Federal statutory rate	35.0%	35.0%	35.0%	35.0%	%
Increase (decrease) due to:					
State income taxes, net of Federal income tax benefit	5.6	5.9	5.0	3.0	
Qualified nuclear decommissioning trust fund income	7.8	21.5			
Domestic production activities deduction	0.3	0.8			
Tax exempt income	(0.2)	(0.5)			
Health care reform legislation			0.6		
Amortization of investment tax credit, net deferred taxes	(4.8)	(13.0)	(0.5)	(0.3)	
Plant basis differences	(4.7)		(0.5)	(21.0)	
Production tax credits and other credits	(2.5)	(7.4)			
Fines and Penalties	(0.1)				
Other(d)	(1.2)	7.1		0.2	

Effective income tax rate	35.2%	49.4%	39.6%	16.9%	%

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

For the Nine Months Ended September 30, 2012	**Exelon(a)**	**Generation(a)**	**ComEd**	**PECO**	**BGE(b)**
U.S. Federal statutory rate	35.0%	35.0%	35.0%	35.0%	35.0%
Increase (decrease) due to:					
State income taxes, net of Federal income tax benefit	(4.7)	2.5	5.4	3.2	2.3
Qualified nuclear decommissioning trust fund income	6.9	10.9			
Tax exempt income	(0.3)	(0.5)			
Health care reform legislation	0.2		0.6		(4.6)
Amortization of investment tax credit, net deferred taxes	(2.3)	(3.3)	(0.5)	(0.3)	2.9
Plant basis differences	(2.2)		(0.2)	(9.7)	7.2
Production tax credits and other credits	(2.6)	(4.3)			
Fines and Penalties	3.8	6.0			
Merger expenses (c)	3.6				(14.0)
Other	(1.3)	0.8	0.2		4.5
Effective income tax rate	36.1%	47.1%	40.5%	28.2%	33.3%

(a) Exelon activity for the three and nine months ended September 30, 2012 includes the results of Constellation and BGE for March 12, 2012 September 30, 2012. Generation activity for the three and nine months ended September 30, 2012 includes the results of Constellation for March 12, 2012 September 30, 2012.
(b) BGE activity represents the activity for the three and nine months ended September 30, 2012. BGE activity for the three months ended September 30, 2012 resulted in zero pre-tax income and zero income taxes. BGE recognized a loss before income taxes for the nine months ended September 30, 2012. As a result, positive percentages represent an income tax benefit for BGE for the nine months ended September 30, 2012.
(c) Prior to the close of the merger, the Registrants recorded the applicable taxes on merger transaction costs assuming the merger would not be completed. Upon closing of the merger, the Registrants reversed such taxes for those merger transaction costs that were determined to be non tax-deductible upon successful completion of a merger.
(d) For the three months ended September 30, 2012, Generation s effective tax rate was affected by the resolution of uncertain Federal tax positions (5.3%), the finalization of prior year tax return calculations 4.2%, changes in the forecasted activity attributable to noncontrolling interests 4.1%, and other 4.1%.

Accounting for Uncertainty in Income Taxes

Exelon, Generation, ComEd, PECO, and BGE have $2,164 million, $1,406 million, $327 million, $44 million, and $0 million, of unrecognized tax benefits as of September 30, 2013, respectively, and $1,024 million, $876 million, $67 million, $44 million, and $0 million, of unrecognized tax benefits as of December 31, 2012, respectively. The unrecognized tax benefits as of September 30, 2013 reflect an increase at Exelon and ComEd attributable to the like-kind exchange position discussed below. Furthermore, Exelon s and Generation s unrecognized tax benefits were increased by $446 million in the second quarter in anticipation of filing a refund claim with respect to legacy Constellation taxable years.

Reasonably possible the total amount of unrecognized tax benefits could significantly increase or decrease within 12 months after the reporting date

Settlement of Income Tax Audits

As of September 30, 2013, Exelon and Generation have approximately $160 million of federal and state unrecognized tax benefits that could significantly increase or decrease within the 12 months after the reporting date as a result of completing federal and state audits and expected statute of limitation expirations that if recognized would decrease the effective tax rate.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Nuclear Decommissioning Liabilities (Exelon and Generation)

AmerGen filed income tax refund claims taking the position that nuclear decommissioning liabilities assumed as part of its acquisition of nuclear power plants are taken into account in determining the tax basis in the assets it acquired. The additional basis results primarily in reduced capital gains or increased capital losses on the sale of assets in nonqualified decommissioning funds and increased tax depreciation and amortization deductions. The IRS disagrees with this position and has disallowed the claims. In November 2008, Generation received a final determination from the Appeals division of the IRS (IRS Appeals) disallowing AmerGen s refund claims. Generation filed a complaint in the United States Court of Federal Claims on February 20, 2009 to contest this determination. During the first and second quarters of 2013, AmerGen and the DOJ completed and filed cross motions for summary judgment. On September 17, 2013, the Court granted the government s motion denying AmerGen s claims for refund. Exelon is currently considering an appeal of the decision to the United States Court of Appeals for the Federal Circuit.

Due to the possibility of final resolution through an appellate decision, Generation continues to believe that it is reasonably possible that the total amount of unrecognized tax benefits may significantly decrease in the next twelve months.

Other Income Tax Matters

Involuntary Conversion, Like-Kind Exchange and Competitive Transition Charges

1999 Sale of Fossil Generating Assets (Exelon and ComEd). Exelon, through its ComEd subsidiary, took two positions on its 1999 income tax return to defer approximately $2.8 billion of tax gain on the sale of ComEd s fossil generating assets. Exelon deferred approximately $1.6 billion of the gain under the involuntary conversion provisions of the IRC. Exelon believed that it was economically compelled to dispose of ComEd s fossil generating plants as a result of the Illinois Act and that the proceeds from the sale of the fossil plants were properly reinvested in qualifying replacement property such that the gain could be deferred over the lives of the replacement property under the involuntary conversion provisions. The remaining approximately $1.2 billion of the gain was deferred by reinvesting the proceeds from the sale in qualifying replacement property under the like-kind exchange provisions of the IRC. The like-kind exchange replacement property purchased by Exelon included interests in three municipal-owned electric generation facilities which were properly leased back to the municipalities. The IRS disagreed with both positions and asserted that the entire gain of approximately $2.8 billion was taxable in 1999.

Competitive Transition Charges (Exelon, ComEd, and PECO). Exelon contended that the Illinois Act and the Competition Act resulted in the taking of certain of ComEd s and PECO s assets used in their respective businesses of providing electricity services in their defined service areas. Exelon filed refund claims with the IRS taking the position that CTCs collected during ComEd s and PECO s transition periods represent compensation for that taking and, accordingly, were excludible from taxable income as proceeds from an involuntary conversion. The tax basis of property acquired with the funds provided by the CTCs would be reduced such that the benefits of the position are temporary in nature. The IRS disallowed the refund claims for the 1999-2001 tax years.

Status of Involuntary Conversion and CTC Positions. In the second quarter of 2010, the IRS offered to settle the disagreement over the involuntary conversion and CTC positions. Exelon concluded, based on that offer, that it had sufficient new information that a remeasurement of the involuntary conversion and CTC positions was required in accordance with applicable accounting standards. As a result of the required remeasurement, Exelon recorded $65 million (after-tax) of interest expense, of which $36 million (after-tax) and $22 million (after-tax) were recorded at ComEd and PECO, respectively. ComEd also recorded a current tax

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

expense of $70 million offset with a tax benefit recorded at Generation of $70 million. In the third quarter of 2010, Exelon and the IRS reached a nonbinding, preliminary agreement to settle Exelon s involuntary conversion on terms consistent with the settlement offer received in the second quarter. As a result of the preliminary agreement, Exelon and ComEd eliminated any liability for unrecognized tax benefits and established a current tax payable to the IRS. Exelon paid $302 million in late 2010 in advance of the final settlement and the assessment. In November 2012, the IRS and Exelon finalized and executed definitive agreements to resolve Exelon s involuntary conversion and CTC positions.

Status of Like-Kind Exchange Position. Exelon has been unable to reach agreement with the IRS regarding the dispute over the like kind exchange position. The IRS has asserted that the Exelon purchase and leaseback transaction is substantially similar to a leasing transaction, known as a SILO, which the IRS does not respect as the acquisition of an ownership interest in property. A SILO is a listed transaction that the IRS has identified as a potentially abusive tax shelter under guidance issued in 2005. Accordingly, the IRS has asserted that the sale of the fossil plants followed by the purchase and leaseback of the municipal owned generation facilities does not qualify as a like-kind exchange and the gain on the sale is fully subject to tax. The IRS has also asserted a penalty of approximately $87 million for a substantial understatement of tax.

Exelon disagrees with the IRS and continues to believe that its like-kind exchange transaction is not the same as or substantially similar to a SILO. Although Exelon has been and remains willing to settle the disagreement on terms commensurate with the hazards of litigation, Exelon does not believe a settlement is possible. Because Exelon believed, as of December 31, 2012, that it was more-likely-than-not that Exelon would prevail in litigation, Exelon and ComEd had no liability for unrecognized tax benefits with respect to the like kind exchange position.

On January 9, 2013, the U.S. Court of Appeals for the Federal Circuit reversed the U.S. Court of Federal Claims and reached a decision for the government in Consolidated Edison v. United States. The Court disallowed Consolidated Edison s deductions stemming from its participation in a LILO transaction that the IRS also has characterized as a tax shelter.

In accordance with applicable accounting standards, Exelon is required to assess whether it is more-likely-than-not that it will prevail in litigation. Exelon continues to believe that its transaction is not a SILO and that it has a strong case on the merits. However, in light of the Consolidated Edison decision and Exelon s current determination that settlement is unlikely, Exelon has concluded that subsequent to December 31, 2012, it is no longer more-likely-than-not that its position will be sustained. As a result, in the first quarter of 2013 Exelon recorded a non-cash charge to earnings of approximately $265 million, which represents the amount of interest expense (after-tax) and incremental state income tax expense for periods through March 31, 2013 that would be payable in the event that Exelon is unsuccessful in litigation. Of this amount, approximately $170 million was recorded at ComEd. Exelon intends to hold ComEd harmless from any unfavorable impacts of the after-tax interest amounts on ComEd s equity. As such, ComEd recorded on its consolidated balance sheet as of March 31, 2013, a $172 million receivable and non-cash equity contributions from Exelon. Exelon and ComEd will continue to accrue interest on the uncertain tax position, and the charges arising from future interest accruals are not expected to be material to the annual operating earnings of Exelon or ComEd. In addition, ComEd will continue to record a receivable and non-cash equity contribution from Exelon in amounts equal to the additional interest recorded by ComEd on the uncertain tax position. Exelon continues to believe that it is unlikely that the $87 million penalty assertion will ultimately be sustained and therefore no liability for the penalty has been recorded.

On September 30, 2013, the Internal Revenue Service issued a notice of deficiency to Exelon for the like-kind exchange position. Exelon will initiate litigation by December 29, 2013 in the United States Tax Court and

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

is not required to remit any part of the asserted tax or penalty in order to litigate the issue. The litigation could take three to five years including appeals, if necessary. Decisions in the Tax Court are not controlled by the Federal Circuit s decision in Consolidated Edison.

As of September 30, 2013, in the event of a fully successful IRS challenge to Exelon s like-kind exchange position, the potential tax and after-tax interest, exclusive of penalties, that could become currently payable may be as much as $840 million, of which approximately $305 million would be attributable to ComEd after consideration of Exelon s agreement to hold ComEd harmless, and the balance at Exelon. Litigation could take several years such that the estimated cash and interest impacts would likely change by a material amount.

Accounting for Final Tangible Property Regulations (Exelon, Generation, ComEd, PECO, and BGE)

On September 19, 2013, the Treasury Department and the IRS published final regulations regarding the tax treatment of costs incurred to acquire, produce, or improve tangible property. The Registrants are currently assessing 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.

Accounting for Generation Repairs (Exelon and Generation)

On April 30, 2013, the IRS issued guidance that will facilitate the determination of the appropriate tax treatment of costs incurred to repair electric generation assets. Exelon and Generation are currently assessing its impact and expect to file a request for change in method of tax accounting for repair costs beginning with its 2014 taxable year.

13. Nuclear Decommissioning (Exelon and Generation)

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 and Generation s Consolidated Balance Sheets from December 31, 2012 to September 30, 2013:

Nuclear decommissioning ARO at December 31, 2012(a)	$ 4,741
Accretion expense	194
Net decrease due to changes in, and timing of, estimated cash flows	(141)
Costs incurred to decommission retired plants	(2)
Nuclear decommissioning ARO at September 30, 2013(a)	$ 4,792

(a) Includes $10 million as the current portion of the ARO at September 30, 2013 and December 31, 2012, respectively, which is included in Other current liabilities on Exelon's and Generation's Consolidated Balance Sheets.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

During the nine months ended September 30, 2013, Generation s ARO increased by approximately $51 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 CARFRs, which have increased from the prior year. The decrease in the ARO due to the changes in, and timing of, estimated cash flows were entirely offset by decreases in Property, plant and equipment within Exelon s and Generation s Consolidated Balance Sheets.

During the nine months ended September 30, 2012, Generation s ARO increased by $916 million. The increase in the ARO was largely driven by four factors: i) changes in the timing of the future nominal cash flows resulting from an assumed five year deferral to 2025 of the acceptance date of spent nuclear fuel by the DOE coupled with the fact that; ii) cash flows affected by this change in timing are re-measured and discounted at current CARFRs, which had dramatically decreased given the lower interest rate environment; iii) an increase in the estimated costs to decommission the Quad Cities and Dresden nuclear units resulting from the completion of updated decommissioning costs studies received during 2012; and iv) accretion of the obligation. The increase in the ARO due to the changes in, and timing of, estimated cash flows resulted in $10 million of expense, which is included in Exelon s and Generation s Consolidated Statements of Operations and Comprehensive Income.

Nuclear Decommissioning Trust Fund Investments

NDT funds have been established for each generating station unit to satisfy Generation s nuclear decommissioning obligations. Generally, NDT funds established for a particular unit may not be used to fund the decommissioning obligations of another unit.

The NDT funds associated with the former ComEd, former PECO and former AmerGen units have been funded with amounts collected from ComEd customers, PECO customers and the previous owners of the former AmerGen plants, respectively. Based on an ICC order, ComEd ceased collecting amounts from its customers to pay for decommissioning costs. PECO is authorized to collect funds, in revenues, for decommissioning the former PECO nuclear plants through regulated rates, and these collections are scheduled through the operating lives of the plants. The amounts collected from PECO customers are remitted to Generation and deposited into the NDT funds for the unit for which funds are collected. Every five years, PECO files a rate adjustment with the PAPUC that reflects PECO's calculations of the estimated amount needed to decommission each of the former PECO units based on updated fund balances and estimated decommissioning costs. The rate adjustment is used to determine the amount collectible from PECO customers. The most recent rate adjustment occurred on January 1, 2013, and the effective rates currently yield annual collections of approximately $24 million. The next five-year adjustment is expected to be reflected in rates charged to PECO customers effective January 1, 2018. With respect to the former AmerGen units, Generation does not collect any amounts, nor is there any mechanism by which Generation can seek to collect additional amounts, from customers. Apart from the contributions made to the NDT funds from amounts collected from ComEd and PECO customers, Generation has not made contributions to the NDT funds.

Any shortfall of funds necessary for decommissioning, determined for each generating station unit, is ultimately required to be funded by Generation, with the exception of a shortfall for the current decommissioning activities at Zion Station, where certain decommissioning activities have been transferred to a third party (see Zion Station Decommissioning below). Generation has recourse to collect additional amounts from PECO customers related to a shortfall of NDT funds for the former PECO units, subject to certain limitations and thresholds, as prescribed by an order from the PAPUC. Generally, PECO will not be allowed to collect amounts associated with the first $50 million of any shortfall of trust funds, on an aggregate basis for all former PECO units, compared to decommissioning obligations, as well as 5% of any additional shortfalls. The initial $50 million and up to 5% of any additional shortfalls would be borne by Generation. No recourse exists to collect additional amounts from ComEd customers for the former ComEd units or from the previous owners of the former AmerGen units. With respect to the former ComEd and PECO units, any funds remaining in the NDTs after all decommissioning has been completed are required to be refunded to ComEd s or PECO s customers, subject to certain limitations that allow sharing of excess funds with Generation related to the former PECO units. With respect to the former AmerGen units, Generation retains any funds remaining in the funds after decommissioning.

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

At September 30, 2013 and December 31, 2012, Exelon and Generation had NDT fund investments totaling $7,776 million and $7,248 million, respectively. The following table provides unrealized gains (losses) on NDT funds for the three and nine months ended September 30, 2013 and 2012:

		Exelon and Generation			
		Three Months Ended September 30,		Nine Months Ended September 30,	
		2013	2012	2013	2012
Net unrealized gains on decommissioning trust funds	Regulatory Agreement Units(a)	$ 103	$ 202	$ 196	$ 352
Net unrealized gains on decommissioning trust funds	Non-Regulatory Agreement Units(b)(c)	46	71	70	101

(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 and Noncurrent payables to affiliates on Generation's Consolidated Balance Sheets.
(b) Excludes $9 million of net unrealized losses and $22 million of net unrealized gains related to the Zion Station pledged assets for the three months ended September 30, 2013 and 2012, respectively, and $5 million of net unrealized losses and $60 million of net unrealized gains related to the Zion Station pledged assets for the nine months ended September 30, 2013 and 2012, respectively. Net unrealized gains (losses) related to Zion Station pledged assets are included in the Payable for Zion Station decommissioning on Exelon's and Generation's Consolidated Balance Sheets.
(c) Net unrealized gains related to Generation's NDT funds associated with Non-Regulatory Agreement Units are included within Other, net in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income.

Interest and dividends on NDT fund investments are recognized when earned and are included in Other, net in Exelon s and Generation s Consolidated Statements of Operations and Comprehensive Income. Interest and dividends earned on the NDT fund investments for the Regulatory Agreement Units are eliminated within Other, net in Exelon s and Generation s Consolidated Statement of Operations and Comprehensive Income.

See Note 3 Regulatory Matters and Note 22 Related Party Transactions of the Exelon 2012 Form 10-K for information regarding regulatory liabilities at ComEd and PECO and intercompany balances between Generation, ComEd and PECO reflecting the obligation to refund to customers any decommissioning-related assets in excess of the related decommissioning obligations.

Zion Station Decommissioning. On September 1, 2010, Generation completed an Asset Sale Agreement (ASA) with EnergySolutions Inc. and its wholly owned subsidiaries, EnergySolutions, LLC (EnergySolutions) and ZionSolutions under which ZionSolutions has assumed responsibility for decommissioning Zion Station, which is located in Zion, Illinois and ceased operation in 1998. On January 7, 2013, EnergySolutions announced that it had entered a definitive acquisition agreement to be 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. See Note 13 Asset Retirement Obligations of the Exelon 2012 Form 10-K for information regarding the specific treatment of assets, including NDT funds, and decommissioning liabilities transferred in the transaction.

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

On July 14, 2011, three people filed a purported class action lawsuit in the United States District Court for the Northern District of Illinois naming ZionSolutions and Bank of New York Mellon as defendants and seeking, among other things, an accounting for use of NDT funds, an injunction against the use of NDT funds, the appointment of a trustee for the NDT funds, and the return of NDT funds to customers of ComEd to the extent legally entitled thereto. If the plaintiffs prevail on the merits of their claims, some or all of the NDT funds may no longer be available to ZionSolutions for decommissioning Zion Station, in which case, the contractual arrangement would require ZionSolutions to utilize a line of credit to complete the decommissioning. In addition, the appointment of a NDT fund trustee in this matter could impact Generation s future decommissioning activities at other stations by setting a precedent for the appointment of trustees for NDT funds. On July 20, 2012, ZionSolutions and Bank of New York Mellon filed a motion to dismiss the amended complaint for failing to state a claim. On July 29, 2013, United States District Court for the Northern District of Illinois dismissed the amended complaint. On August 26, 2013, the plaintiffs filed a notice of appeal with the United States Court of Appeals for the Seventh Circuit. The parties will submit briefs in support of their positions, following which the Court of Appeals will typically schedule oral argument.

ZionSolutions is subject to certain restrictions on its ability to request reimbursements from the Zion Station NDT funds as defined within the ASA. Therefore, the transfer of the Zion Station assets did not qualify for asset sale accounting treatment and, as a result, the related NDT funds were reclassified to pledged assets for Zion Station decommissioning within Generation s and Exelon s Consolidated Balance Sheets and will continue to be measured in the same manner as prior to the completion of the transaction. Additionally, the transferred ARO for decommissioning was replaced with a payable to ZionSolutions in Generation s and Exelon s Consolidated Balance Sheets. Changes in the value of the Zion Station NDT assets, net of applicable taxes, will be recorded as a change in the payable to ZionSolutions. At no point will the payable to ZionSolutions exceed the project budget of the costs remaining to decommission Zion Station. Generation has retained its obligation to the SNF following ZionSolutions completion of its contractual obligations, to transfer the SNF at Zion Station to the DOE for ultimate disposal, and to complete all remaining decommissioning activities associated with the SNF storage facility. Generation has a liability of approximately $81 million, which is included within the nuclear decommissioning ARO at September 30, 2013. Generation also has retained NDT assets to fund its obligation to maintain and transfer the SNF at Zion Station and to complete all remaining decommissioning activities for the SNF storage facility. Any shortage of funds necessary to maintain the SNF and decommission the SNF storage facility is ultimately required to be funded by Generation. Any Zion Station NDT funds remaining after the completion of all decommissioning activities will be returned to ComEd customers in accordance with the applicable orders. The following table provides the pledged assets and payable to ZionSolutions, and withdrawals by ZionSolutions at September 30, 2013 and December 31, 2012:

	Exelon and Generation	
	September 30, 2013	**December 31, 2012**
Carrying value of Zion Station pledged assets	$ 486	$ 614
Payable to Zion Solutions(a)	443	564
Current portion of payable to Zion Solutions(b)	104	132
Withdrawals by Zion Solutions to pay decommissioning costs(c)	458	335

(a) Excludes a liability recorded within Exelon s and Generation s Consolidated Balance Sheets related to the tax obligation on the unrealized activity associated with the Zion Station NDT Funds. The NDT Funds will be utilized to satisfy the tax obligations as gains and losses are realized.
(b) Included in Other current liabilities within Exelon s and Generation s Consolidated Balance Sheets.
(c) Cumulative withdrawals since September 1, 2010.

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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. On April 1, 2013, Generation submitted its NRC-required biennial decommissioning funding status report as of December 31, 2012. As of December 31, 2012, Generation provided adequate funding assurance for all of its units, including Limerick Unit 1, where Generation has in place a $115 million parent guarantee to cover the NRC minimum funding assurance requirements. On October 2, 2013, the NRC issued summary findings from the NRC Staff s review of the 2013 decommissioning funding status reports for all 104 operating reactors, including the Generation operating units. Based on that review, the NRC Staff determined that Generation provided decommissioning funding assurance under the NRC regulations for all of its operating units, including Limerick Unit 1.

On January 31, 2013, Generation received a letter from the NRC indicating that the NRC has identified potential apparent violations of its regulations because of alleged inaccuracies in the Decommissioning Funding Status reports for 2005, 2006, 2007, and 2009. The NRC asserted that Generation s status reports deliberately reflected cost estimates for decommissioning its nuclear plants that were less than what the NRC says are the minimum amounts required by NRC regulations. Generation met with the NRC on April 30, 2013 for a pre-decisional enforcement conference to provide additional information to explain why Generation believes that it complied with the regulatory requirements and did not deliberately or otherwise provide incomplete or inaccurate information in its decommissioning funding status reports. While Generation does not believe that any sanction is appropriate, the ultimate outcome of this proceeding including the amount of a potential fine or sanction, if any, is uncertain. The January 31, 2013 letter from the NRC does not take issue with Generation s current funding status, and as reflected in Generation's April 1, 2013 decommissioning funding status report referenced above, Generation continues to provide adequate funding assurance for each of its units. In the normal course of NRC review, Generation has received a series of data requests that are unrelated to the potential apparent violations and the pre-decisional enforcement conference. Generation continues to cooperate with the NRC and provide the requested information. Generation does not have a definite date on which it will receive a response from the NRC. Although the government shutdown may delay receipt of a response from the NRC, Generation anticipates that the NRC will issue its findings this year.

In addition, on June 24, 2013, Exelon received a subpoena from the SEC requesting that Exelon provide the SEC with certain documents generally relating to Exelon and Generation s reporting and funding of the future decommissioning of Exelon s nuclear power plants. Exelon and Generation are cooperating with the SEC and providing the requested documents.

14. Retirement Benefits (Exelon, Generation, ComEd, PECO and BGE)

Exelon sponsors defined benefit pension plans and other postretirement benefit plans for essentially all Generation, ComEd, PECO, BGE and BSC employees.

Defined Benefit Pension and Other Postretirement Benefits

During the first quarter of 2013, Exelon received an updated valuation of its legacy pension and other postretirement benefit obligations to reflect actual census data as of January 1, 2013. This valuation resulted in an increase to the pension obligation of $8 million and a decrease to the other postretirement benefit obligation of $39 million. Additionally, accumulated other comprehensive loss decreased by approximately $75 million (after tax) and regulatory assets increased by approximately $93 million. During the second quarter of 2013, Exelon received the updated valuation for the legacy Constellation pension and other postretirement obligations to reflect actual census data as of January 1, 2013. This valuation resulted in an increase to the pension obligation of $23

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

million and a decrease to the other postretirement benefit obligation of $12 million. Additionally, accumulated other comprehensive loss increased by approximately $2 million (after tax) and regulatory assets increased by approximately $14 million.

The following tables present the components of Exelon s net periodic benefit costs for the three and nine months ended September 30, 2013 and 2012. The 2013 pension benefit cost for all plans is calculated using an expected long-term rate of return on plan assets of 7.50% and a discount rate of 3.92%. The 2013 other postretirement benefit cost is calculated using an expected long-term rate of return on plan assets of 6.45% for funded plans and a discount rate of 4.00% for all plans. Certain other postretirement benefit plans are not funded. A portion of the net periodic benefit cost is capitalized within the Consolidated Balance Sheets.

	Pension Benefits Three Months Ended September 30,		Other Postretirement Benefits Three Months Ended September 30,	
	2013	2012	2013	2012
Service cost	$ 79	$ 76	$ 41	$ 38
Interest cost	163	181	48	53
Expected return on assets	(253)	(258)	(33)	(28)
Amortization of:				
Transition obligation				2
Prior service cost (benefit)	3	5	(4)	(3)
Actuarial loss	140	117	20	19
Settlement charges	9	9		
Curtailment gain				(5)
Net periodic benefit cost	$ 141	$ 130	$ 72	$ 76

	Pension Benefits Nine Months Ended September 30,		Other Postretirement Benefits Nine Months Ended September 30,	
	2013	2012	2013	2012
Service cost	$ 238	$ 211	$ 122	$ 114
Interest cost	488	524	145	157
Expected return on assets	(761)	(742)	(99)	(86)
Amortization of:				
Transition obligation				8
Prior service cost (benefit)	10	12	(14)	(10)
Actuarial loss	421	338	62	58
Settlement charges	9	9		
Contractual termination benefit cost(a)		14		6
Curtailment gain				(7)
Net periodic benefit cost	$ 405	$ 366	$ 216	$ 240

(a) ComEd and BGE established regulatory assets of $1 million and $4 million, respectively, for their portion of the second quarter 2012 contractual termination benefit charge.

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The amounts below were included in Capital expenditures and Operating and maintenance expense during the three and nine months ended September 30, 2013 and 2012, for Generation s, ComEd s, PECO s, BGE s and BSC s allocated portion of the pension and postretirement benefit plan costs.

	Three Months Ended September 30,		Nine Months Ended September 30,	
Pension and Other Postretirement Benefit Costs	**2013**	**2012**	**2013**	**2012**
Generation	$ 87	$ 85	$ 259	$ 259
ComEd	77	75	231	212
PECO	11	12	32	38
BGE(a)(b)	14	14	41	46
BSC(c)	24	20	58	63

(a) BGE's pension and postretirement benefit costs for the nine months ended September 30, 2012 include $12 million of costs incurred prior to the closing of Exelon's merger with Constellation on March 12, 2012. These amounts are not included in Exelon's net periodic benefit costs for the nine months ended September 30, 2012 shown in the first table of the Defined Benefit Pension and Other Postretirement Benefits section above.

(b) BGE s pension and other postretirement benefit costs for the three and nine months ended September 30, 2012 includes a $3 million contractual termination benefit charge, which was recorded as a regulatory asset as of September 30, 2012.

(c) These amounts primarily represent amounts billed to Exelon's subsidiaries through intercompany allocations. These amounts are not included in the Generation, ComEd, PECO or BGE amounts above. As of September 30, 2012, ComEd and BGE each recorded a regulatory asset of $1 million related to their BSC-billed portion of the second quarter 2012 contractual termination benefit charge.

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. Exelon has contributed $255 million to its qualified pension plans in 2013, of which Generation, ComEd, PECO and BGE contributed $113 million, $115 million, $11 million and $0 million, respectively. 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 $82 million in 2013, of which Generation, ComEd, PECO, and BGE will make payments of $7 million, $1 million, $0 million, and $2 million, respectively.

Unlike 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 regulator expectations and best assure continued recovery). In 2013, Exelon anticipates funding its other postretirement benefit plans based on the funding considerations discussed above, with the exception of those plans previously sponsored by Constellation and AmerGen, which remain unfunded. Exelon expects to make other postretirement benefit plan contributions, including benefit payments related to unfunded plans, of approximately $276 million in 2013, of which Generation, ComEd, PECO, and BGE expect to contribute $108 million, $112 million, $21 million, and $17 million, respectively.

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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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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. This investment strategy would tend to result in a lower expected rate of return on plan assets in future years. 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.

Defined Contribution Savings Plans

The Registrants participate in various 401(k) defined contribution savings plans that are sponsored by Exelon. The plans are qualified under applicable sections of the IRC and allow employees to contribute a portion of their pre-tax income in accordance with specified guidelines. All Registrants match a percentage of the employee contributions up to certain limits. The following table presents the matching contributions to the savings plans during the three and nine months ended September 30, 2013 and 2012:

	Three Months Ended September 30,		Nine Months Ended September 30,	
Savings Plan Matching Contributions	**2013**	**2012**	**2013**	**2012**
Exelon	$ 18	$ 19	$ 61	$ 55
Generation	8	9	29	25
ComEd	6	5	16	14
PECO	2	2	6	5
BGE(a)	1	1	5	5
BSC(b)	1	2	5	6

(a) BGE's matching contributions for the nine months ended September 30, 2012 include $1 million of costs incurred prior to the closing of Exelon's merger with Constellation on March 12, 2012, which is not included in Exelon's matching contributions for the nine months ended September 30, 2012.
(b) These amounts primarily represent amounts billed to Exelon's subsidiaries through intercompany allocations. These costs are not included in the Generation, ComEd, PECO or BGE amounts above.

15. Stock-Based Compensation Plans (Exelon, Generation, ComEd, PECO and BGE)

Exelon grants stock-based awards through its LTIP, which primarily includes stock options, restricted stock units and performance share awards. At September 30, 2013, there were approximately 16 million shares authorized for issuance under the LTIP. For the three and nine months ended September 30, 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 performance shares and restricted stock. The performance share awards granted in 2013 will 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 performance period, the Compensation Committee also approved a one-time grant of performance share transition awards in 2013, which will vest one-third after one year, with the remaining balance vesting over a two-year performance period.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

The following table presents the stock-based compensation expense included in Exelon s Consolidated Statements of Operations and Comprehensive Income for the three and nine months ended September 30, 2013 and 2012:

Components of Stock-Based Compensation Expense	Three Months Ended September 30, 2013	2012	Nine Months Ended September 30, 2013	2012
Performance share awards	$ 12	$ 5	$ 41	$ 32
Stock options	1	2	3	13
Restricted stock units	13	12	49	41
Other stock-based awards	1	1	4	3
Total stock-based compensation expense included in operating and maintenance expense	27	20	97	89
Income tax benefit	(10)	(8)	(37)	(34)
Total after-tax stock-based compensation expense	$ 17	$ 12	$ 60	$ 55

The following table presents stock-based compensation expense (pre-tax) for the three and nine months ended September 30, 2013 and 2012:

Subsidiaries	Three Months Ended September 30, 2013	2012	Nine Months Ended September 30, 2013	2012
Generation	$ 10	$ 9	$ 38	$ 33
ComEd	3	2	7	9
PECO	1	1	4	4
BGE(a)	1	1	5	4
BSC(b)	12	7	43	39
Total(c)	$ 27	$ 20	$ 97	$ 89

(a) BGE's stock-based compensation expense (pre-tax) for the nine months ended September 30, 2012 excludes $2 million of cost incurred in 2012 prior to the closing of Exelon's merger with Constellation on March 12, 2012. This amount is not included in Exelon's stock-based compensation expense for the nine months ended September 30, 2012 shown in the tables titled Components of Stock-Based Compensation Expense and Subsidiaries above.

(b) These amounts primarily represent amounts billed to Exelon's subsidiaries through intercompany allocations. These amounts are not included in the Generation, ComEd, PECO and BGE amounts above.

(c) The stock-based compensation expense (pre-tax) for the three and nine months ended September 30, 2013 reflects the impact of changes to the retirement eligibility requirements for employees participating in the LTIP. In addition, the stock-based compensation expense at ComEd reflects the adoption of the ComEd Key Manager Long-Term Performance Program in 2013 for certain employees, which is not considered stock-based compensation expense under the applicable authoritative guidance. In 2012, these employees participated in the Exelon Restricted Stock Award Program.

There were no significant stock-based compensation costs capitalized during the three and nine months ended September 30, 2013 and 2012.

Stock Options

Non-qualified stock options are granted under the LTIP with exercise prices equal to the fair market value of the underlying stock at the date of grant. Generally, the stock options vest ratably over a four-year vesting period and expire ten years from the date of grant.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

There were no stock options granted in 2013. The Compensation Committee eliminated stock option grants by changing the mix of long-term incentives for senior vice presidents (SVPs) and higher officers from 75% performance shares and 25% stock options to 67% performance shares and 33% restricted stock units (RSUs).

At September 30, 2013, $3 million of total unrecognized compensation costs related to nonvested stock options are expected to be recognized over the remaining weighted-average period of 1.8 years.

Restricted Stock Units

Restricted stock units are granted under the LTIP with the majority being settled in a specific number of shares of common stock after the service condition has been met. The corresponding cost of services is measured based on the grant date fair value of the restricted stock unit issued. The 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.

At September 30, 2013 and December 31, 2012, Exelon had obligations related to outstanding restricted stock units not yet settled of $67 million and $58 million, respectively, which are included in common stock in Exelon s Consolidated Balance Sheets. As of September 30, 2013 and December 31, 2012, Exelon had no obligations related to outstanding restricted stock units that will be settled in cash. During the three months ended September 30, 2013 and 2012, Exelon settled restricted stock units with a fair value totaling $3 million and $4 million, respectively. During the nine months ended September 30, 2013 and 2012, Exelon settled restricted stock units with a fair value totaling $26 million and $23 million, respectively. At September 30, 2013, $69 million of total unrecognized compensation costs related to nonvested restricted stock units are expected to be recognized over the remaining weighted-average period of 2.2 years.

Performance Share and Performance Share Transition Awards

Performance share awards are granted under the LTIP with the 2013 performance share awards 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 2012 performance share awards are being settled 50% in common stock and 50% in cash over the three-year vesting term with executive vice presidents and higher officers receiving 100% cash if certain ownership requirements are satisfied. The performance shares granted prior to 2012 generally vest and settle over a three-year period with the holders receiving shares of common stock and/or cash annually during the vesting period.

The one-time 2013 performance share transition awards, which provide an opportunity to earn an award contingent on company performance, will be settled 50% in common stock and 50% in cash, except for awards granted to executive vice presidents and higher officers that may be settled 100% in cash if certain ownership requirements are satisfied. One-third of the award vests and is payable after a one-year performance period while the remaining two-thirds vests and is payable after a two-year performance period.

The payout of the 2013 performance share awards and one-time performance share transition awards are based on the Company s performance against specific operational and financial goals set annually during the respective performance periods. As a result, the 2013 performance share awards have been divided into equal tranches for the purpose of expense recognition as though the respective award were multiple awards; with each tranche representing a corresponding fiscal year. The one-time performance share transition awards have also been divided into multiple tranches for the purpose of expense recognition. One tranche reflects the one-third of the awards that vests and are payable after a one-year period. The two-thirds of the one-time performance share transition awards that are subject to a two-year performance period have also been divided into equal tranches; with each tranche representing a corresponding fiscal year. The grant date for each tranche of the 2013 performance share and one-time performance share transition awards is the date in which the performance goals for that fiscal year are approved and communicated, which typically occurs at the corresponding January Compensation Committee meeting.

The 2013 performance share awards and one-time performance share transition awards are recorded at fair value at the grant dates for each tranche, with the estimated grant date fair value based on the expected payout of the award, which may range from 50% to 150% of the payout target. The 2013 performance share awards also include a total shareholder return modifier (TSR) that may increase or decrease the award up to 25% and an individual performance modifier (IPM) that can decrease the award by up to 50% or increase the award by up to 10% for senior vice presidents and higher officers or up to 20% for vice presidents. The one-time performance share transition award is not affected by either TSR or the IPM.

The common stock portion of the performance share and one-time performance share transition awards is considered an equity award being valued based on Exelon s stock price on the grant date. The cash portion of the awards is considered a liability award which is remeasured each reporting period based on Exelon s current stock price. As the value of the common stock and cash portions of the awards are based on Exelon s stock price during the performance period, coupled with changes in the total shareholder return modifier and expected payout of the award, the compensation costs are subject to volatility until payout is established.

The 2012 performance share awards are recorded at fair value at the date of grant with the estimated grant date fair value based on the expected payout of the award, which may range from 75% to 125% of the payout target. The common stock portion is considered an equity award with the 75% payout floor being valued based on Exelon s stock price on the grant date. The cash portion of the award is considered a liability award with the 75% payout floor being remeasured each reporting period based on Exelon s current stock price. The expected payout in excess of the 75% floor for the equity and liability portions are remeasured each reporting period based on Exelon s current stock price and changes in the expected payout of the award; therefore these portions of the award are subject to volatility until the payout is established.

For nonretirement-eligible employees, stock-based compensation costs are recognized over the vesting period of three years using the graded-vesting method. For performance share and one-time performance share transition awards granted to retirement-eligible employees, the value of the performance shares in recognized ratably over the vesting period, which is the year of grant.

At September 30, 2013 and December 31, 2012, Exelon had obligations related to outstanding performance shares not yet settled of $63 million and $53 million, respectively. During the three months ended September 30, 2013 and 2012, Exelon settled performance shares with a fair value totaling $3 million and $3 million, respectively, of which $3 million and $0 million was paid in cash, respectively. During the nine months ended September 30, 2013 and 2012, Exelon settled performance shares with a fair value totaling $25 million and $22 million, respectively, of which $12 million and $3 million was paid in cash, respectively. As of September 30, 2013, $32 million of total unrecognized compensation costs related to nonvested performance shares are expected to be recognized over the remaining weighted-average period of 2.3 years. In addition, as of September 30, 2013, $19 million of total unrecognized compensation costs related to nonvested one-time performance share transition awards are expected to be recognized over the remaining weighted-average period of 1.3 years.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

16. Changes in Accumulated Other Comprehensive Income (Exelon, Generation, and PECO)

The following table presents changes in accumulated other comprehensive income (loss) (AOCI) by component for nine months ended September 30, 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	25	(1)	73	(5)	46	138
Amounts reclassified from AOCI(b)	(194)		157		5	(32)
Net current-period OCI	(169)	(1)	230	(5)	51	106
Ending balance	$ 199	$ (1)	$ (2,907)	$ (5)	$ 53	$ (2,661)
Generation(a)						
Beginning balance	$ 512	$	$	$	$ 1	$ 513
OCI before reclassifications	12	(1)		(5)	47	53
Amounts reclassified from AOCI(b)	(328)				5	(323)
Net current-period OCI	(316)	(1)		(5)	52	(270)
Ending balance	$ 196	$ (1)	$	$ (5)	$ 53	$ 243
PECO(a)						
Beginning balance	$	$ 1	$	$	$	$ 1
OCI before reclassifications						
Amounts reclassified from AOCI(b)						
Net current-period OCI						
Ending balance	$	$ 1	$	$	$	$ 1

(a) All amounts are net of tax. Amounts in parenthesis represent a decrease in accumulated other comprehensive income.

(b) See next table for details about these reclassifications.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

ComEd, PECO, and BGE did not have any reclassifications out of AOCI to Net Income during the three and nine months ended September 30, 2013. The following table presents amounts reclassified out of AOCI to Net Income for Exelon and Generation during the three and nine months ended September 30, 2013:

Three Months Ended September 30, 2013

Details about AOCI components	Items reclassified out of AOCI(a) Exelon	Generation	Affected line item in the statement where Net Income is presented
Gains and (losses) on cash flow hedges			
Energy related hedges	$ 84	$ 84	Operating revenues
Other cash flow hedges	(1)	(1)	Interest expense
	83	83	Total before tax
	(35)	(33)	Tax (expense)
	$ 48	$ 50	Net of tax
Amortization of pension and other postretirement benefit plan items			
Actuarial losses	(92)		(b)
Deferred compensation unit plan	(1)		(c)
	(93)		Total before tax
	37		Tax benefit
	$ (56)	$	Net of tax
Total Reclassifications for the period	$ (8)	$ 50	Net of Tax

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Nine Months Ended September 30, 2013

Details about AOCI components	**Items reclassified out of AOCI(a)**		**Affected line item in the statement where Net Income is presented**
	Exelon	**Generation**	
Gains and (losses) on cash flow hedges			
Energy related hedges	$ 324	$ 543	Operating revenues
Other cash flow hedges	(2)		Interest expense
	322	543	Total before tax
	(128)	(215)	Tax (expense)
	$ 194	$ 328	Net of tax
Amortization of pension and other postretirement benefit plan items			
Prior service costs	$ (1)	$	(b)
Actuarial losses	(257)		(b)
Deferred compensation unit plan	(1)		(c)
	(259)		Total before tax
	102		Tax benefit
	$ (157)	$	Net of tax
Equity investments			
Capital activity	$ (8)	$ (8)	Equity in losses of unconsolidated affiliates
	(8)	(8)	Total before tax
	3	3	Tax benefit
	$ (5)	$ (5)	Net of tax
Total Reclassifications for the period	$ 32	$ 323	Net of Tax

(a) All amounts are net of tax. 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 14 for additional details).
(c) Amortization of deferred compensation unit 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 three and nine months ended September 30, 2013 and 2012:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
Exelon				
Pension and non-pension postretirement benefit plans:				
Prior service benefit reclassified to periodic benefit cost	$	$ 1	$	$ 2
Actuarial loss reclassified to periodic cost	33	28	97	82
Transition obligation reclassified to periodic cost		1		2
Pension and non-pension postretirement benefit plans valuation adjustment	(6)	(43)	44	(51)

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	Three Months Ended September 30, 2013	Three Months Ended September 30, 2012	Nine Months Ended September 30, 2013	Nine Months Ended September 30, 2012
Deferred compensation unit valuation adjustment			6	
Change in unrealized loss on cash flow hedges	(35)	(57)	(109)	36
Change in unrealized income on equity investments	9	11	32	15
Change in unrealized loss on marketable securities				1
Total	$ 1	$ (59)	$ 70	$ 87
Generation				
Change in unrealized loss on cash flow hedges	$ (36)	$ (113)	$ (209)	$ (122)
Change in unrealized income on equity investments	9	11	32	15
Total	$ (27)	$ (102)	$ (177)	$ (107)

17. Earnings Per Share and Equity (Exelon and PECO)

Earnings per Share (Exelon)

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 these stock options, performance share awards and restricted stock on the weighted average number of shares outstanding (in millions) used in calculating diluted earnings per share:

	Three Months Ended September 30, 2013	Three Months Ended September 30, 2012	Nine Months Ended September 30, 2013	Nine Months Ended September 30, 2012
Net income attributable to common shareholders	$ 738	$ 296	$ 1,224	$ 782
Average common shares outstanding basic	857	854	856	804
Assumed exercise of stock options, performance share awards and restricted stock	3	3	4	2
Average common shares outstanding diluted	860	857	860	806

The number of stock options not included in the calculation of diluted common shares outstanding due to their antidilutive effect was approximately 20 million for the three and nine months ended September 30, 2013 and 18 million and 13 million for the three and nine months ended September 30, 2012, respectively.

Under share repurchase programs, 35 million shares of common stock are held as treasury stock with a cost of $2.3 billion as of September 30, 2013. In 2008, Exelon management decided to defer indefinitely any share repurchases.

Preferred Securities Redemption (Exelon and PECO)

On March 25, 2013, PECO announced that it issued a notice of redemption for all of its outstanding preferred securities with a redemption date of May 1, 2013. PECO had $87 million of cumulative preferred securities that were redeemable at its option at any time for the redemption price established when each series of securities were issued. The redemption premium of $6 million is treated as a reduction to Net income to arrive at Net income attributable to common shareholders utilized in the calculation of the earnings per share for Exelon. As a result of the redemption, PECO is now indirectly, wholly-owned by Exelon.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

18. Commitments and Contingencies (Exelon, Generation, ComEd, PECO and BGE)

The following is an update to the current status of commitments and contingencies set forth in Note 19 of the Exelon 2012 Form 10-K.

Commitments

Energy Commitments

As of September 30, 2013, Generation s commitments relating to purchases from unaffiliated utilities and others of energy, capacity and transmission rights, are as indicated in the following table:

	Net Capacity Purchases(a)	REC Purchases(b)	Transmission Rights Purchases(c)	Purchased Energy from CENG	Total
2013	$ 86	$ 17	$ 7	$ 186	$ 296
2014	396	124	26	745	1,291
2015	368	97	13		478
2016	285	57	2		344
2017	223	16	2		241
Thereafter	526	5	34		565
Total	$ 1,884	$ 316	$ 84	$ 931	$ 3,215

(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 September 30, 2013, net of fixed capacity payments expected to be received by Generation under contracts to resell such acquired capacity to third parties under long-term capacity sale contracts. These capacity payments represent the fixed, or pre-determined, payment for output from contracted generation facilities. Output in this context generally includes products such as energy, capacity, and various ancillary services associated with generating facilities. Expected payments include certain capacity charges which are contingent on plant availability.

(b) Power-related purchases include firm REC purchase agreements. 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.

In connection with Constellation s comprehensive agreement with EDF in October 2010, Constellation s and EDF s existing power purchase agreements with CENG were modified to be unit-contingent through the end of their original term in 2014. Under these agreements, CENG has the ability to fix the energy price on a forward basis by entering into monthly energy hedge transactions for a portion of the future sale, while any unhedged portions will be provided at market prices by default. Additionally, beginning in 2015 and continuing to the end of the life of the respective plants, Generation agreed to purchase 50.01% of the available output of CENG s nuclear plants at market prices. Generation discloses in the table above commitments to purchase from CENG at fixed prices. All commitments to purchase at market prices, which include all purchases subsequent to December 31, 2014, are excluded from the table. Generation continues to own a 50.01% membership interest in CENG that is accounted for as an equity method investment. See Note 6 Investment in Constellation Energy Nuclear Group, LLC for more details on this arrangement.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

ComEd s, PECO s and BGE s electric supply procurement, curtailment services, REC and AEC purchase commitments as of September 30, 2013 are as follows:

	Expiration within						
	Total	**2013**	**2014**	**2015**	**2016**	**2017**	**2018 and beyond**
ComEd							
Electric supply procurement(a)	$ 878	$ 142	$ 323	$ 136	$ 137	$ 140	$
Renewable energy and RECs(b)	1,604	20	67	74	76	77	1,290
PECO							
Electric supply procurement(c)	886	211	584	91			
AECs	15	1	2	2	2	2	6
BGE							
Electric supply procurement(d)	1,122	227	669	226			
Curtailment services(e)	147	13	46	41	34	13	

(a) ComEd entered into various contracts for the procurement of electricity that started to expire in 2012, and will continue to expire through 2017. ComEd is permitted to recover its electric supply procurement costs from retail customers with no mark-up. See Note 5 Regulatory Matters for additional information.
(b) ComEd entered into 20-year contracts for renewable energy and RECs beginning June 2012. ComEd is permitted to recover its renewable energy and REC costs from retail customers with no mark-up. Pursuant to the ICC s Order on December 19, 2012, ComEd s commitments under the existing long-term contracts for energy and associated RECs were reduced in the first quarter of 2013. See Note 5 Regulatory Matters for additional information.
(c) PECO entered into various contracts for the procurement of electric supply to serve its default service customers that expire between 2013 and 2015. PECO is permitted to recover its electric supply procurement costs from default service customers with no mark-up in accordance with its PAPUC-approved DSP Programs. See Note 5 Regulatory Matters for additional information.
(d) BGE entered into various contracts for the procurement of electricity that expire between 2013 and 2015. The cost of power under these contracts is recoverable under MDPSC approved fuel clauses. See Note 5 Regulatory Matters for additional information.
(e) BGE has entered into various contracts with curtailment services providers related to transactions in PJM's capacity market. See Note 5 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 (and with respect to coal, commitments to sell coal). 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 September 30, 2013, these net commitments were as follows:

	Expiration within						
	Total	**2013**	**2014**	**2015**	**2016**	**2017**	**2018 and beyond**
Generation	$ 7,901	$ 339	$ 1,199	$ 1,233	$ 1,021	$ 1,050	$ 3,059
PECO	477	54	128	100	78	36	81
BGE	603	46	123	52	51	50	281

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Other Purchase Obligations

The Registrants other purchase obligations as of September 30, 2013, which primarily represent commitments for services, materials and information technology, are as follows:

		Expiration within					
	Total	**2013**	**2014**	**2015**	**2016**	**2017**	**2018 and beyond**
Exelon	$ 269	$ 33	$ 38	$ 32	$ 31	$ 31	$ 104
Generation	628	133	178	127	40	38	112
ComEd(a)	82	7	41	5	5	5	19
PECO(a)	54	19	25	1	1	1	7
BGE(a)	25	2	21	2			

(a) Purchase obligations include commitments related to smart meter installation. See Note 5 Regulatory Matters for additional information.

Construction Commitments

Generation has committed to the construction of a solar PV facility in Los Angeles County, California. The first portion of the project began operations in December 2012, with six additional blocks coming online in 2013 and an expectation of full commercial operation in the first half of 2014. Generation's estimated remaining commitment for the project is $180 million.

On July 3, 2013, Generation executed a Turbine Supply Agreement to expand its Beebe wind project in Michigan. The estimated remaining commitment under the contract is $52 million and achievement of commercial operations is expected in 2014.

On July 26, 2013, Generation executed an engineering procurement and construction contract to expand its Perryman, Maryland generation site with 120MW of new natural gas-fired generation to satisfy certain merger commitments. The estimated remaining commitment under the contract is $80 million and achievement of commercial operation is expected in 2015. See Note 4 Mergers and Acquisitions for additional information on commitments to develop or assist in development of new generation in Maryland resulting from the merger.

Refer to Note 3 Regulatory Matters of the Exelon 2012 Form 10-K for information on investment programs associated with regulatory mandates, such as ComEd s Infrastructure Investment Plan under EIMA, PECO s Smart Meter Procurement and Installation Plan and BGE s comprehensive smart grid initiative.

Constellation Merger Commitments

In December 2011, Exelon and Constellation reached a settlement with the State of Maryland and the City of Baltimore and other interested parties in connection with the regulatory proceedings related to the merger that was pending before the MDPSC. As part of this settlement and the application for approval of the merger by MDPSC, 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 more than $1 billion.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

On February 17, 2012, the MDPSC approved the merger with conditions. Many of the conditions were reflective of the settlement agreements described above. 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. See Note 4 Merger and Acquisitions of the Exelon 2012 Form 10-K for additional information on the merger.

Description	Payment Period	BGE	Generation	Exelon	Statement of Operations Location
BGE rate credit of $100 per residential customer(a)	Q2 2012	$ 113	$	$ 113	Revenues
Customer investment fund to invest in energy efficiency and low-income energy assistance to BGE customers	2012 to 2014			113.5	O&M Expense
Contribution for renewable energy, energy efficiency or related projects in Baltimore	2012 to 2014			2	O&M Expense
Charitable contributions at $7 million per year for 10 years	2012 to 2021	28	35	70	O&M Expense
State funding for offshore wind development projects	Q2 2012			32	O&M Expense
Miscellaneous tax benefits	Q2 2012	(2)		(2)	Taxes Other Than Income
Total		$ 139	$ 35	$ 328.5	

(a) Exelon made a $66 million equity contribution to BGE in the second quarter of 2012 to fund the after-tax amount of the rate credit as directed in the MDPSC order approving the merger transaction.

Contingencies

Commercial Commitments

The Registrants commercial commitments as of September 30, 2013, representing commitments potentially triggered by future events were as follows:

	Exelon	Generation	ComEd	PECO	BGE
Letters of credit (non-debt)(a)	$ 1,514	$ 1,463	$ 26	$ 22	$ 1
Guarantees	4,908(b)	1,271(c)	209(d)	181(e)	252(f)
Nuclear insurance premiums(g)	3,096	3,096			
Total commercial commitments	$ 9,518	$ 5,830	$ 235	$ 203	$ 253

(a) Non-debt letters of credit maintained to provide credit support for certain transactions as requested by third parties.

(b) Primarily reflects parental guarantees issued on behalf of Generation to allow the flexibility needed to conduct business with counterparties without having to post other forms of collateral. Also reflects guarantees issued to ensure performance under specific contracts, preferred securities of financing trusts, property leases, indemnifications, NRC minimum funding assurance requirements and $211 million on behalf of CENG nuclear generating facilities for credit support and miscellaneous guarantees. The estimated net exposure for obligations under commercial transactions covered by these guarantees was $0.6 billion at September 30, 2013, which represents the total amount Exelon could be required to fund based on September 30, 2013 market prices.

(c) Primarily reflects guarantees issued to ensure performance under energy marketing and other specific contracts and $211 million on behalf of CENG nuclear generating facilities for credit support. The estimated net exposure for obligations under commercial transactions covered by these guarantees was $0.2 billion at September 30, 2013, which represents the total amount Generation could be required to fund based on September 30, 2013 market prices.

(d) Primarily reflects full and unconditional guarantees of $200 million Trust Preferred Securities of ComEd Financing III, which is a 100% owned finance subsidiary of ComEd.

(e) Primarily reflects full and unconditional guarantees of $178 million Trust Preferred Securities of PECO Trust III and IV, which are 100% owned finance subsidiaries of PECO.

(f) Primarily reflects full and unconditional guarantees of $250 million Trust Preferred Securities of BGE Capital Trust II, which is a 100% owned finance subsidiary of BGE.

(g) 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.

Nuclear Insurance (Exelon and Generation)

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 September 30, 2013, the current liability limit per incident was $13.6 billion and is subject to change to account for the effects of inflation and changes in the number of licensed reactors. An inflation adjustment must be made at least once every 5 years and the last inflation adjustment was made effective September 10, 2013. In accordance with the Price-Anderson Act, Generation maintains financial protection at levels equal to the amount of liability insurance available from private sources through the purchase of private nuclear energy liability insurance for public liability claims that could arise in the event of an incident. As of September 30, 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 $2.8 billion. In addition, the U.S. Congress could impose revenue-raising measures on the nuclear industry to pay public liability claims exceeding the $13.6 billion limit for a single incident.

Additionally, Generation is also 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. Premiums paid to NEIL by its members are subject to assessment for adverse loss experience (the retrospective premium obligation). The maximum combined retrospective premium amount that Generation could be required to pay due to participation in the Price-Anderson Act retrospective rating plan for power reactors and the NEIL retrospective premium obligation is $3.1 billion, which is included above in the Commercial Commitments table. See the Nuclear Insurance section within Note 19 Commitments and Contingencies of the Exelon 2012 Form 10-K for additional details on Generation s nuclear insurance premiums.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Indemnifications Related to Sale of Sithe (Exelon and Generation)

On January 31, 2005, subsidiaries of Generation completed a series of transactions that resulted in Generation s sale of its investment in Sithe. Specifically, subsidiaries of Generation consummated the acquisition of Reservoir Capital Group s 50% interest in Sithe and subsequently sold 100% of Sithe to Dynegy, Inc. (Dynegy).

The estimated maximum possible exposure to Exelon related to the guarantees provided as part of the sales transaction to Dynegy was approximately $200 million at September 30, 2013. Generation believes that it is remote that it will be required to make any additional payments under the guarantee, and currently has no recorded liabilities associated with this guarantee. Generation expects that the exposure covered by this guarantee will expire in 2014. The guarantee is included above in the Commercial Commitments table under guarantees.

Indemnifications Related to Sale of TEG and TEP (Exelon and Generation)

On February 9, 2007, Tamuin International Inc. (TII), a wholly owned subsidiary of Generation, sold its 49.5% ownership interests in TEG and TEP to a subsidiary of AES Corporation for $95 million in cash plus certain purchase price adjustments. In connection with the transaction, Generation entered into a guarantee agreement under which Generation guaranteed the timely payment of TII s obligations to the subsidiary of AES Corporation pursuant to the terms of the purchase and sale agreement relating to the sale of TII s ownership interests. Generation was required to perform in the event that TII did not pay any obligation covered by the guarantee that was not otherwise subject to a dispute resolution process. Portions of the exposures covered by this guarantee expired in 2008, and the remaining guarantee expired in the third quarter of 2013. Generation was not required to make payments under the guarantee, and therefore, has no further obligation related to this guarantee as of September 30, 2013.

Environmental Issues

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, ComEd, PECO or BGE is one of several PRPs that may be responsible for ultimate remediation of each location.

ComEd has identified 42 sites, 16 of which have been approved for cleanup by the Illinois EPA or the U.S. EPA and 26 that are currently under some degree of active study and/or remediation. ComEd expects the majority of the remediation at these sites to continue through at least 2016.

PECO has identified 26 sites, 16 of which have been approved for cleanup by the PA DEP and 10 that are currently under some degree of active study and/or remediation. PECO expects the majority of the remediation at these sites to continue through at least 2020.

BGE has identified 13 former gas manufacturing or purification sites that it currently owns or owned at one time through a predecessor s acquisition. Two gas manufacturing sites require some level of

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

remediation and ongoing monitoring under the direction of the MDE. The required costs at these two sites are not considered material. One gas purification site is in the initial stages of investigation at the direction of the MDE.

ComEd, pursuant to an ICC order, and PECO, pursuant to settlements of natural gas distribution rate cases with the PAPUC, are currently recovering environmental remediation costs of former MGP facility sites through customer rates. BGE is authorized to and is currently recovering environmental costs for the remediation of former MGP facility sites from customers; however, while BGE does not have a rider for MGP clean-up costs, BGE has historically received recovery of actual clean-up costs in distribution rates. ComEd, PECO and BGE have recorded regulatory assets for the recovery of these costs. During the third quarter of 2013, ComEd and PECO completed an annual study of their future estimated MGP remediation requirements. The results of these studies indicated that additional remediation would be required at certain sites; accordingly, ComEd and PECO increased their reserves and regulatory assets by less than $1 million and $6 million, respectively. See Note 5 Regulatory Matters for additional information regarding the associated regulatory assets.

As of September 30, 2013 and December 31, 2012, the Registrants had accrued the following undiscounted amounts for environmental liabilities in other current liabilities and other deferred credits and other liabilities within their respective Consolidated Balance Sheets:

September 30, 2013	Total Environmental Investigation and Remediation Reserve	Portion of Total Related to MGP Investigation and Remediation
Exelon	$ 345	$ 280
Generation	56	
ComEd	237	232
PECO	51	48
BGE	1	

December 31, 2012	Total Environmental Investigation and Remediation Reserve	Portion of Total Related to MGP Investigation and Remediation
Exelon	$ 351	$ 298
Generation	42	
ComEd	261	254
PECO	47	44
BGE	1	

The Registrants cannot reasonably estimate whether they will incur other significant liabilities for additional investigation and remediation costs at these or additional sites identified by the Registrants, environmental agencies or others, or whether such costs will be recoverable from third parties, including customers.

Water Quality

Section 316(b) of the Clean Water Act. Section 316(b) requires that the cooling water intake structures at electric power plants reflect the best technology available to minimize adverse environmental impacts, and is implemented through state-level NPDES permit programs. All of Generation s and CENG's power generation facilities with cooling water systems are subject to the regulations. Facilities without closed-cycle recirculating systems (e.g., cooling towers) are potentially most affected. 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.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

On March 28, 2011, the U.S. EPA issued the proposed regulation under Section 316(b). The proposal does not require closed-cycle cooling (e.g., cooling towers) as the best technology available to address impingement and entrainment. The proposal provides the state permitting agency with discretion to determine the best technology available to limit entrainment (drawing aquatic life into the plants cooling system) mortality, including application of a cost-benefit test and the consideration of a number of site-specific factors. After consideration of these factors, the state permitting agency may require closed cycle cooling, an alternate technology, or determine that the current technology is the best available. The proposed rule also imposes limits on impingement (trapping aquatic life on screens) mortality, which likely will be accomplished by the installation of screens or another technology at the intake. Exelon filed comments on the proposed regulation on August 18, 2011, stating its support for a number of its provisions (e.g., cooling towers not required as best technology available, and the use of site-specific and cost benefit analysis) while also noting a number of technical provisions that require revision to take into account existing unit operations and practices within the industry.

In June 2012, the U.S. EPA published two Notices of Data Availability (NODA) seeking public comment on alternate compliance technologies for impingement and the use of a public opinion survey to calculate the so-called non-use benefits of the rule. Exelon filed comments for each NODA, supporting the additional flexibility afforded by the impingement NODA, and opposing the NODA relating to calculation of non-use benefits due to its inaccurate and unreliable methodologies that would artificially inflate the benefits of proposed technologies that would otherwise not be cost-effective. On June 27, 2013, the U.S. EPA agreed to amend the court approved Settlement Agreement to extend the deadline to issue a final rule until November 4, 2013; on October 30, 2013 the Agency invoked the *force majeure* provision of the Settlement Agreement to extend the final rule deadline until November 20, 2013 due to the early October 2013 federal government shutdown. Until the rule is finalized, the state permitting agencies will continue to apply their best professional judgment to address impingement and entrainment.

Salem and Other Power Generation Facilities. In June 2001, the NJDEP issued a renewed NPDES permit for Salem, allowing for the continued operation of Salem with its existing cooling water system. NJDEP advised PSEG, in July 2004 that it strongly recommended reducing cooling water intake flow commensurate with closed-cycle cooling as a compliance option for Salem. PSEG submitted an application for a renewal of the permit on February 1, 2006. In the permit renewal application, PSEG analyzed closed-cycle cooling and other options and demonstrated that the continuation of the Estuary Enhancement Program, an extensive environmental restoration program at Salem, is the best technology to meet the Section 316(b) requirements. PSEG continues to operate Salem under the approved June 2001 NPDES permit while the NPDES permit renewal application is being reviewed. If the final permit or Section 316(b) regulations ultimately requires the retrofitting of Salem s cooling water intake structure to reduce cooling water intake flow commensurate with closed-cycle cooling, Exelon s and Generation s share of the total cost of the retrofit and any resulting interim replacement power would likely be in excess of $430 million, based on a 2006 estimate, and would result in increased depreciation expense related to the retrofit investment.

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

Given the uncertainties associated with the requirements that will be contained in the final rule, Generation cannot predict the eventual outcome or estimate the effect that compliance with any resulting Section 316(b) or interim state requirements will have on the operation of its and CENG's generating facilities and its future results of operations, cash flows and financial position.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Groundwater Contamination. In October 2007, a subsidiary of Constellation entered into a consent decree with the MDE relating to groundwater contamination at a third-party facility that was licensed to accept fly ash, a byproduct generated by coal-fired plants. The consent decree required the payment of a $1 million penalty, remediation of groundwater contamination resulting from the ash placement operations at the site, replacement of drinking water supplies in the vicinity of the site, and monitoring of groundwater conditions. Prior to the Merger, Constellation recorded in its Consolidated Balance Sheets total liabilities of approximately $30 million to comply with the consent decree with an additional $3 million recognized through purchase accounting. During the three months ended September 30, 2013, Generation increased its reserve by $2 million based on an update of future estimated remediation costs. The remaining liability as of September 30, 2013, is approximately $15 million. In addition, a private party has asserted claims relating to groundwater contamination. Generation believes that these claims are without merit and is vigorously contesting them. As of September 30, 2013, Generation believes that it is remote that it will be required to make payments under these private party claims.

Air Quality

Cross State Air Pollution Rule (CSAPR). On July 11, 2008, the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit Court) vacated the CAIR, which had been promulgated by the U.S. EPA to reduce power plant emissions of SO_2 and NO_x. The D.C. Circuit Court later remanded the CAIR to the U.S. EPA, without invalidating the entire rulemaking, so that the U.S. EPA could correct CAIR in accordance with the D.C. Circuit Court s July 11, 2008 opinion. On July 7, 2011, the U.S. EPA published the final rule, known as the CSAPR. The CSAPR requires 28 states in the eastern half of the United States to significantly improve air quality by reducing power plant emissions that cross state lines and contribute to ground-level ozone and fine particle pollution in other states.

Numerous entities challenged the CSAPR in the D.C. Circuit Court, and some requested a stay of the rule pending the Court s consideration of the matter on the merits. On December 30, 2011, the Court granted a stay of the CSAPR, and directed the U.S. EPA to continue the administration of CAIR in the interim. On August 21, 2012, a three-judge panel of the D.C. Circuit Court held that the U.S. EPA has exceeded its authority in certain material aspects of the CSAPR and vacated the rule and remanded it to the U.S. EPA for further rulemaking consistent with its decision. The Court also ordered that CAIR remain in effect pending finalization of CSAPR on remand. On January 24, 2013, the Court denied petitions for reconsideration of the ruling by the three-judge panel. In June 2013, the U.S. Supreme Court granted the U.S. EPA s petition to review the D.C. Circuit Court s CSAPR decision. Oral argument has been scheduled for December 10, 2013.

Under the CSAPR, generation units were to receive allowances based on historic heat input and intrastate, and limited interstate, trading of allowances was permitted. The CSAPR restricted entirely the use of pre-2012 allowances. Existing SO_2 allowances under the ARP would remain available for use under ARP. As of September 30, 2013, Generation had $64 million of emission allowances carried at the lower of weighted average cost or market.

EPA Mercury and Air Toxics Standards (MATS). The MATS rule became final on April 16, 2012. The MATS rule reduces emissions of toxic air pollutants, and finalized the new source performance standards for fossil fuel-fired electric utility steam generating units (EGUs). The MATS rule requires coal-fired EGUs to achieve high removal rates of mercury, acid gases and other metals from air emissions. To achieve these standards, coal units with no pollution control equipment installed (uncontrolled coal units) will have to make capital investments and incur higher operating expenses. It is expected that smaller, older, uncontrolled coal units will retire rather than make these investments. Coal units with existing controls that do not meet the required standards may need to upgrade existing controls or add new controls to comply. In addition, the new standards will require oil units to achieve high removal rates of metals. Owners of oil units not currently meeting the proposed emission standards

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

may choose to convert the units to light oils or natural gas, install control technologies or retire the units. The MATS rule requires generating stations to meet the new standards three years after the rule takes effect, April 16, 2015, with specific guidelines for an additional one or two years in limited cases. Numerous entities have challenged MATS in the D.C. Circuit Court, and Exelon was granted permission by the Court to intervene in support of the rule. A decision by the Court will not occur until 2014. The outcome of the appeal, and its impact on power plant operators investment and retirement decisions, is uncertain.

Exelon, along with the other co-owners of Conemaugh Generating Station are moving forward with plans to improve the existing scrubbers and install Selective Catalytic Reduction (SCR) controls to meet the mercury removal requirements of MATS.

In addition, as of September 30, 2013, Exelon had a $691 million net investment in coal-fired plants in Georgia and Texas subject to long-term leases extending through 2028-2032. While Exelon currently estimates the value of these plants at the end of the lease term will be in excess of the recorded residual lease values, after the impairment recorded in the second quarter of 2013, final applications of the CSAPR and MATS regulations could negatively impact the end-of-lease term values of these assets, which could result in a future impairment loss that could be material. See Note 7 Impairment of Long-Lived Assets for additional information.

National Ambient Air Quality Standards (NAAQS). The U.S. EPA previously announced that it would complete a review of all NAAQS by 2014. Oral argument in the litigation (*State of Miss. v. EPA*) of the final 2008 ozone standard occurred in the D.C. Circuit Court in November 2012 and a final Court decision was issued on July 23, 2013 with the 2008 primary ozone standard upheld, but the secondary standard remanded to EPA for reconsideration. Concurrent with litigation of the 2008 ozone standard, the U.S. EPA continues its regular, periodic review of the ozone NAAQS and is expected to propose revisions in the fall of 2014, with preliminary indications that the U.S. EPA will likely propose a tightened standard. It is unclear at this point in time whether the U.S. EPA will be able to respond to the Court remand of the secondary 2008 ozone standard on a timeframe that would be any quicker than that of the U.S. EPA s current, periodic review schedule. In December 2012, the U.S. EPA issued its final revisions to the Agency s particulate matter (PM) NAAQS. In its final rule, the U.S. EPA lowered the annual PM2.5 standard, but declined to issue a new secondary NAAQS to improve urban visibility. The U.S. EPA indicated in its final rule that by 2020 it expects most areas of the country will be in attainment of the new PM2.5 NAAQS based on currently expected regulations, such as the MATS regulation. It is unclear if the vacatur of the CSAPR, one of the regulations that the U.S. EPA is relying on to assist with future PM reduction, would alter the U.S. EPA s view since either CAIR or a finalized CSAPR regulation would be in effect leading up to 2020. In March 2013, a number of industry coalitions filed a joint lawsuit challenging the new PM2.5 standard. Also during early 2013, the D.C. Circuit remanded several rules for implementation of earlier PM2.5 NAAQS to the U.S. EPA for revision of certain aspects of the rules, with a requirement that the U.S. EPA re-promulgate regulations in conformance with the correct subparts of the Clean Air Act.

In addition to these NAAQS, the U.S. EPA also finalized nonattainment designations for certain areas in the United States for the 2010 one-hour SO_2 standard on August 5, 2013, and indicated that additional nonattainment areas will be designated in a future rulemaking. EPA will require states to submit state implementation plans (SIPs) for nonattainment areas by April 2015. With regard to Texas and Maryland, no nonattainment areas were identified in EPA s final designation rule. With regard to Illinois and Pennsylvania, several counties, or portions of counties, in each state were identified as nonattainment. The U.S. EPA will follow the approach outlined in a February 2013 EPA strategy document that establishes a process and timeline for the Agency to address additional designations in states counties under a future rulemaking. Nonattainment county compliance with the one-hour SO_2 standard is required by October 2018. While significant 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 SO_2 emissions in support of attainment of the one hour SO_2 standard.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Notices and Finding of Violations and Midwest Generation Bankruptcy. In December 1999, ComEd sold several generating stations to Midwest Generation, LLC (Midwest Generation), a subsidiary of Edison Mission Energy (EME). Under the terms of the sale agreement, Midwest Generation and EME assumed responsibility for environmental liabilities associated with the ownership, occupancy, use and operation of the stations, including responsibility for compliance by the stations with environmental laws before their purchase by Midwest Generation. Midwest Generation and EME additionally agreed to indemnify and hold ComEd and its affiliates harmless from claims, fines, penalties, liabilities and expenses arising from third party claims against ComEd resulting from or arising out of the environmental liabilities assumed by Midwest Generation and EME under the terms of the agreement governing the sale. In connection with Exelon s 2001 corporate restructuring, Generation assumed ComEd s rights and obligations with respect to its former generation business, including its rights and obligations under the sale agreement with Midwest Generation and EME.

On August 6, 2007, ComEd received a NOV addressed to it and Midwest Generation from the U.S. EPA, alleging, in relevant part, that ComEd and Midwest Generation violated and are continuing to violate provisions of the Clean Air Act as a result of the modification and/or operation of six electric generation stations located in northern Illinois that have been owned and operated by Midwest Generation since their purchase from ComEd in 1999. In August 2009, the United States and the State of Illinois filed a complaint against Midwest Generation with the U.S. District Court for the Northern District of Illinois initiating enforcement proceedings with respect to most of the alleged Clean Air Act violations set forth in the NOV. Neither ComEd nor Exelon was named as a defendant in this original complaint. In March 2010, the District Court granted Midwest Generation s partial motion to dismiss all but one of the claims against Midwest Generation. The District Court held that Midwest Generation cannot be liable for any alleged violations relating to construction that occurred prior to Midwest Generation s ownership of the stations. In May 2010, the government plaintiffs filed an amended complaint against Midwest Generation asserting claims substantially similar to those in the original complaint, and added ComEd and EME as defendants. The amended complaint seeks injunctive relief and civil penalties against all defendants, although not all of the claims specifically pertain to ComEd. On March 16, 2011, the District Court granted ComEd s motion to dismiss the May 2010 complaint in its entirety as it relates to ComEd. On January 3, 2012, upon leave of the District Court, the government parties appealed the dismissal of ComEd to the U.S. Circuit Court of Appeals for the Seventh Circuit. On July 8, 2013, the Circuit Court affirmed the District Court s dismissal of the complaint against ComEd. On September 19, 2013, the Circuit Court denied the petition for a rehearing filed by the governmental parties. Exelon, Generation and ComEd have concluded that, in light of the Circuit Court decision, the likelihood of loss is remote. Therefore, no reserve has been established.

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.

The Bankruptcy Court approved the rejection of a coal rail car lease under which Midwest Generation had agreed to reimburse ComEd for all obligations. The rejection left Generation as the party responsible to make remaining payments under the lease. In January 2013, Generation made the final $10 million payment due under the lease agreement which had been reserved for at December 31, 2012. As a result of the bankruptcy filing, Exelon and Generation have recorded liabilities as of September 30, 2013 of $3 million for estimated payments for asbestos personal injury claims filed pre-Petition Date. Exelon and Generation currently expect Midwest Generation or its successor will remain responsible for asbestos personal injury claims filed post-Petition Date, and as such have recorded no liability for such amounts. Requirements for Generation to ultimately satisfy such claims could have a material adverse impact on Exelon s and Generation s future results of operations. During the second quarter of 2013, ComEd filed proofs of claim of $21 million with the Bankruptcy Court for amounts owed by EME and Midwest Generation for the coal rail car lease, ComEd utility payments and certain legal costs. As of September 30, 2013, Exelon and ComEd have not recorded a receivable for the filed proofs of claim because recovery of such amount cannot be assured at this point in the bankruptcy. Exelon and ComEd will not record financial benefits associated with claim recoveries until realized.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

As of the Petition Date, Generation had wholesale power transactions with Edison Mission Marketing and Trading, an affiliate of Midwest Generation not included in the bankruptcy proceeding. Generation expects these transactions to be fully settled in the normal course.

Certain environmental laws and regulations subject current and prior owners of properties or generators of hazardous substances at such properties to liability for remediation costs of environmental contamination. As a prior owner of the generating stations, ComEd (and Generation, through its agreement in the 2001 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 requiring remediation, with the determination of the allocation among the parties subject to many uncertain factors, including the impact of Midwest Generation s bankruptcy. Additionally, the obligations of EME and Midwest Generation to ComEd under the sale agreement, including the environmental indemnity, may be discharged in the bankruptcy proceeding. In such circumstances, ComEd (and Generation, through ComEd) may only have an unsecured claim against EME and Midwest Generation for the environmental remediation costs that would have otherwise been obligations of EME and Midwest Generation under the sale agreement. This unsecured claim may yield a fractional, or possibly no, recovery for ComEd and Generation.

On October 18, 2013, NRG Energy entered into an agreement to buy EME's portfolio of generation. EME may continue to solicit alternative transaction proposals from third parties through December 6, 2013. Any such transaction would require the approval of the U.S. Bankruptcy Court. ComEd and Generation are currently evaluating the terms of the agreements to determine the impact they could have on the bankruptcy proceedings and ComEd s and Generation s claims.

ComEd and Generation continue to monitor the bankruptcy proceedings and available public information as to potential environmental exposures regarding the Midwest Generation plant sites. Midwest Generation publicly disclosed in its quarter ending June 30, 2013 Form 10-Q that (i) it has accrued a probable amount of approximately $8 million for estimated environmental investigation and remediation costs under CERCLA, or similar laws, for the investigation and remediation of contaminated property at four Midwest Generation plant sites, (ii) it has identified stations for which a reasonable estimate for investigation and/ or remediation cannot be made and (iii) it and the Illinois EPA entered into Compliance Commitment Agreements outlining specified environmental remediation measures and groundwater monitoring activities to be undertaken at its Crawford, Powerton, Joliet, Will County and Waukegan generating stations. At this time, however, ComEd and Generation do not have sufficient information to reasonably assess the potential likelihood or magnitude of any such exposures. Further, Midwest Generation s bankruptcy process will likely extend into mid-2014, and unless there is a successful transaction involving NRG Energy, the outcome is uncertain, including whether the facilities will continue to operate and the identity or financial wherewithal of potential future plant owners. 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 no liability has been recorded as of September 30, 2013. Any liability imposed on ComEd or Generation for environmental matters relating to the generating stations could have a material adverse impact on their future results of operations and cash flows.

Solid and Hazardous Waste

Cotter Corporation. The U.S. EPA has advised Cotter Corporation (Cotter), a former ComEd subsidiary, that it is potentially liable in connection with radiological contamination at a site known as the West Lake Landfill in Missouri. On February 18, 2000, ComEd sold Cotter to an unaffiliated third party. As part of the sale, ComEd agreed to indemnify Cotter for any liability arising in connection with the West Lake Landfill. In connection with Exelon s 2001 corporate restructuring, this responsibility to indemnify Cotter was transferred to Generation. On May 29, 2008, the U.S. EPA issued a Record of Decision approving the remediation option submitted by Cotter and the two other PRPs that required additional landfill cover. The current estimated cost of

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

the anticipated landfill cover remediation for the site is approximately $42 million, which will be allocated among all PRPs. Generation has accrued what it believes to be an adequate amount to cover its anticipated share of such liability. By letter dated January 11, 2010, the U.S. EPA requested that the PRPs perform a supplemental feasibility study for a remediation alternative that would involve complete excavation of the radiological contamination. On September 30, 2011, the PRPs submitted the final supplemental feasibility study to the U.S. EPA for review. In June 2012, the U.S. EPA requested that the PRPs perform additional analysis and groundwater sampling as part of the supplemental feasibility study that could take up to one year to complete, and subsequently requested additional analysis sampling and modeling to be conducted in 2013 and 2014. In light of these additional requests, it is unknown when the U.S EPA will propose a remedy for public comment. Thereafter the U.S. EPA will select a final remedy and enter into a Consent Decree with the PRPs to effectuate the remedy. A complete excavation remedy would be significantly more expensive than the previously selected additional cover remedy; however, Generation believes the likelihood that the U.S. EPA would require a complete excavation remedy is remote.

On August 8, 2011, Cotter was notified by the DOJ that Cotter is considered a PRP with respect to the government s clean-up costs for contamination attributable to low level radioactive residues at a former storage and reprocessing facility named Latty Avenue near St. Louis, Missouri. The Latty Avenue site is included in ComEd s indemnification responsibilities discussed above as part of the sale of Cotter. The radioactive residues had been generated initially in connection with the processing of uranium ores as part of the U.S. government s Manhattan Project. Cotter purchased the residues in 1969 for initial processing at the Latty Avenue facility for the subsequent extraction of uranium and metals. In 1976, the NRC found that the Latty Avenue site had radiation levels exceeding NRC criteria for decontamination of land areas. Latty Avenue was investigated and remediated by the United States Army Corps of Engineers pursuant to funding under the Formerly Utilized Sites Remedial Action Program. The DOJ has not yet formally advised the PRPs of the amount that it is seeking, but it is believed to be approximately $90 million. The DOJ and the PRPs agreed to toll the statute of limitations until August 2014 so that settlement discussions could proceed. Based on Exelon s preliminary review, it appears probable that Exelon has liability to Cotter under the indemnification agreement and has established an appropriate accrual for this liability.

On February 28, 2012, and April 12, 2012, two lawsuits were filed in the U.S. District Court for the Eastern District of Missouri against 15 and 14 defendants, respectively, including Exelon, Generation and ComEd (the Exelon defendants) and Cotter. The suits allege that individuals living in the North St. Louis area developed some form of cancer due to the defendants negligent or reckless conduct in processing, transporting, storing, handling and/or disposing of radioactive materials. Plaintiffs have asserted claims for negligence, strict liability, emotional distress, medical monitoring, and violations of the Price Anderson Act. The complaints do not contain specific damage claims. On May 30, 2012, the plaintiffs filed voluntary motions to dismiss the Exelon defendants from both lawsuits which were subsequently granted. On October 23, 2012, a third lawsuit was filed in the same court on behalf of three additional plaintiffs against Cotter and seven other defendants, but not Exelon. On April 19, 2013, a fourth lawsuit was filed in the same court on behalf of two additional plaintiffs against Cotter and seven other defendants, but not Exelon. On June 18, 2013, a fifth lawsuit was filed in the same court on behalf of one plaintiff against eight defendants, including Cotter but not Exelon. On July 31, 2013, a sixth lawsuit was filed in the same court on behalf of two plaintiffs against Cotter and four other defendants, but not Exelon. The allegations in these latter four complaints mirror the initially filed lawsuits. In the event of a finding of liability, it is reasonably possible that Exelon would be considered liable due to its indemnification responsibilities of Cotter described above. On March 27, 2013, the U.S. District Court dismissed all state common law actions brought under the initial two lawsuits; and also found that the plaintiffs had not properly brought the actions under the Price Anderson Act. On July 8, 2013, the plaintiffs filed amended complaints under the Price Anderson Act. Cotter moved to dismiss the amended complaints and has motions currently pending before the court. At this stage of the litigation, Exelon cannot estimate a range of loss, if any.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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 potentially responsible parties 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, EPA issued its Record of Decision specifying the remedies to be implemented at the site based on the information and recommendations of the PRP investigation. The costs to implement these remedies are still expected to be in the range of \$50 million to \$64 million. The U.S. EPA is expected to make a final selection of one of the alternatives in 2013. Based on Exelon s preliminary review, it appears probable that Exelon has liability and has established an appropriate accrual for its share of the estimated clean-up costs. BGE is indemnified by a wholly owned subsidiary of Generation for most of the costs related to this settlement and clean-up of the site.

Rossville Ash Site. The Rossville Ash Site is a 32-acre property located in Rosedale, Baltimore County, MD. which was used for the placement of fly ash from 1983-2007. The property is owned by Constellation Power Source Generation, Inc.(CPSG). In 2008, CPSG investigated and remediated the property by entering it into the MD 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. We currently estimate the cost to close the site to be approximately \$6 million.

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, MD. The U.S. EPA offered BGE and three other PRPs the opportunity to conduct an environmental investigation and present cleanup recommendations at the site. In addition, the U.S. EPA is seeking recovery from the PRPs of \$1.7 million for past cleanup and investigation costs at the site. On March 11, 2013, BGE and three other PRP s signed an Administrative Settlement Agreement and Order on Consent with the U.S. EPA which requires the PRP s to conduct a Remedial Investigation and Feasibility Study at the site to determine what, if any, are the appropriate and recommended cleanup activities for the site. The ultimate outcome of this proceeding is uncertain. Since the U.S. EPA has not selected a cleanup remedy and the allocation of the cleanup costs among the PRPs has not been determined, an estimate of the range of BGE s reasonably possible loss, if any, cannot be determined.

Climate Change Regulation. Exelon is subject to climate change regulation or legislation at the Federal, regional and state levels. In 2007, the U.S. Supreme Court ruled that GHG emissions are pollutants subject to regulation under the new motor vehicle provisions of the Clean Air Act. Consequently, on December 7, 2009, the U.S. EPA issued an endangerment finding under Section 202 of the Clean Air Act regarding GHGs from new motor vehicles and on April 1, 2010 issued final regulations limiting GHG emissions from cars and light trucks effective on January 2, 2011. While such regulations do not specifically address stationary sources, such as a generating plant, it is the U.S. EPA s position that the regulation of GHGs under the mobile source provisions of the Clean Air Act has triggered the permitting requirements under the Prevention of Significant Deterioration (PSD) and Title V operating permit sections of the Clean Air Act for new and modified stationary sources effective January 2, 2011. Therefore, on May 13, 2010, the U.S. EPA issued final regulations (the Tailoring Rule) relating to these provisions of the Clean Air Act for major stationary sources of GHG emissions that apply to new sources that emit greater than 100,000 tons per year, on a CO_2 equivalent basis, and to modifications to

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existing sources that result in emissions increases greater than 75,000 tons per year on a CO_2 equivalent basis. These thresholds became effective January 2, 2011, apply for six years and will be reviewed by the U.S. EPA for future applicability thereafter. On July 2, 2012 the U.S. EPA declined to lower GHG permit thresholds in its final Step 3 Tailoring Rule update. The U.S. EPA will review permit thresholds again in a 2015 rulemaking process. On June 26, 2012, the United States Court of Appeals for the District of Columbia, in a *per curium* decision, dismissed industry and state petitions challenging the U.S. EPA s Tailpipe Rule for cars and light duty trucks, the endangerment finding for GHG s from stationary sources, and the Tailoring Rule. On October 15, 2013 the U.S. Supreme Court granted industry petitions to review one aspect of the PSD permitting regulations. Under the PSD regulations, new and modified major stationary sources could be required to install best available control technology, to be determined on a case by case basis. Generation could be significantly affected by the regulations if it were to build new plants or modify existing plants.

On June 25, 2013, President Obama announced The President s Climate Action Plan, a summary of executive branch actions intended to: reduce carbon emissions; prepare the United States for the impacts of climate change; and lead international efforts to combat global climate change and prepare for its impacts. Concurrent with the announcement of the Administration s plan, the President also issued a Memorandum for the Administrator of the Environmental Protection Agency that focused on power generation sector carbon reductions under the Section 111 New Source Performance Standards (NSPS) section of the federal Clean Air Act. The memorandum directs the EPA Administrator to issue two sets of proposed rulemakings with regard to power plant carbon emissions under Section 111 of the Clean Air Act.

The first rulemaking, under Section 111(b) of the Clean Air Act is to focus on establishing carbon regulations for new fossil-fuel power plants. This rulemaking was proposed on September 20, 2013 and is to be finalized in a timely fashion. In the proposed rule EPA sets separate standards for fossil-fuel fired utility boilers and natural gas fired stationary combustion turbines.

The second rulemaking, under Section 111(d) of the Clean Air Act is to focus on modified, reconstructed and existing fossil power plants. The rulemaking is to be proposed no later than June 1, 2014, be finalized no later than June 1, 2015, and require that states submit to EPA their implementation plans no later than June 30, 2016. In developing this rulemaking, EPA is directed to consider a number of factors, including options to reduce costs, options to ensure the continued use of a range of energy sources and technologies, options that are consistent with reliable and affordable power, and options that allow for the use of market-based instruments, performance standards and other regulatory flexibilities.

To the extent that the final Section 111(d) rule results in emission reductions from fossil fuel fired plants, and thereby imposes some form of direct or indirect price of carbon in competitive electricity markets, Exelon s overall low carbon generation portfolio results could benefit.

Litigation and Regulatory Matters

Except to the extent noted below, the circumstances set forth in Note 19 of the Exelon 2012 Form 10-K describe, in all material respects, the current status of litigation matters. The following is an update to that discussion.

Asbestos Personal Injury Claims (Exelon, Generation and BGE)

Exelon and Generation. Generation maintains a reserve for claims associated with asbestos-related personal injury actions in certain facilities that are currently owned by Generation or were previously owned by ComEd and PECO. The reserve is recorded on an undiscounted basis and excludes the estimated legal costs associated with handling these matters, which could be material.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

At September 30, 2013 and December 31, 2012, Generation had reserved approximately $65 million and $63 million, respectively, in total for asbestos-related bodily injury claims. As of September 30, 2013, approximately $17 million of this amount related to 211 open claims presented to Generation, while the remaining $48 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.

BGE. Since 1993, BGE and certain Constellation subsidiaries (now Generation) have been involved in several actions concerning asbestos. The actions are based upon the theory of "premises liability," alleging that BGE and certain Constellation subsidiaries knew of and exposed individuals to an asbestos hazard. In addition to BGE and certain Constellation subsidiaries, numerous other parties are defendants in these cases.

Approximately 480 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.

Continuous Power Interruption (ComEd)

Section 16-125 of the Illinois Public Utilities Act provides that in the event an electric utility, such as ComEd, experiences a continuous power interruption of four hours or more that affects (in ComEd s case) more than 30,000 customers, the utility may be liable for actual damages suffered by customers as a result of the interruption and may be responsible for reimbursement of local governmental emergency and contingency expenses incurred in connection with the interruption. Recovery of consequential damages is barred. The affected utility may seek from the ICC a waiver of these liabilities when the utility can show that the cause of the interruption was unpreventable damage due to weather events or conditions, customer tampering, or certain other causes enumerated in the law.

On August 18, 2011, ComEd sought from the ICC a determination that ComEd is not liable for damage compensation to customers in connection with the July 11, 2011 storm system that produced multiple power interruptions that in the aggregate affected more than 900,000 customers in ComEd s service territory, as well as for five other storm systems that affected ComEd s customers during June and July 2011 (Summer 2011 Storm Docket). In addition, on September 29, 2011, ComEd sought from the ICC a determination that it was not liable for damage compensation related to the February 1, 2011 blizzard (February 2011 Blizzard Docket).

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

On June 5, 2013, the ICC approved a complete waiver of liability for five of the six summer storms and the February 2011 blizzard. However, the ICC held that for the July 11, 2011 storm, 34,559 interruptions were preventable and therefore no waiver should apply. As required by the ICC s Order, ComEd will notify relevant customers that they may be entitled to seek reimbursement of incurred costs in accordance with a claims procedure established under ICC rules and regulations. In addition, the ICC found that ComEd did not systematically fail in its duty to provide adequate, reliable and safe service. As a result, the ICC rejected the Illinois Attorney General s request for the ICC to open an investigation into ComEd s infrastructure and storm hardening investments.

Following the ICC s June 26, 2013 denial of ComEd s request for rehearing, on June 27, 2013 ComEd filed an appeal of both the summer and winter storm dockets with the Illinois Appellate Court regarding the ICC s interpretation of Section 16-125 of the Illinois Public Utilities Act. ComEd cannot predict the outcome of appeals.

As a result of the ICC s June 5, 2013 ruling, ComEd established a liability which was not material, for potential reimbursements for actual damages incurred by the 34,559 customers covered by the ICC s June 5, 2013 Order. The liability recorded represents the low end of a range of potential losses given that no amount within the range represents a better estimate. ComEd s ultimate liability will be based on actual claims eligible for reimbursement as well as the outcome of the appeal. Although reimbursements for actual damages will differ from the estimated accrual recorded, at this time ComEd does not expect the difference to be material to ComEd s results of operations or cash flows.

ComEd has not recorded an accrual for reimbursement of local governmental emergency and contingency expenses as a range of loss, if any, cannot be reasonably estimated at this time, but may be material to ComEd s results of operations and cash flows.

Securities Class Action (Exelon)

Three federal securities class action lawsuits were filed in the United States District Courts for the Southern District of New York and the District of Maryland between September 2008 and November 2008 against Constellation. The cases were filed on behalf of a proposed class of persons who acquired publicly traded securities, including the Series A Junior Subordinated Debentures (Debentures), of Constellation between January 30, 2008 and September 16, 2008, and who acquired Debentures in an offering completed in June 2008. The securities class actions generally allege that Constellation, a number of its former officers or directors, and the underwriters violated the securities laws by issuing a false and misleading registration statement and prospectus in connection with Constellation s June 27, 2008 offering of the Debentures. The securities class actions also allege that Constellation issued false or misleading statements or was aware of material undisclosed information which contradicted public statements, including in connection with its announcements of financial results for 2007, the fourth quarter of 2007, the first quarter of 2008 and the second quarter of 2008 and the filing of its first quarter 2008 Form 10-Q. The securities class actions sought, among other things, certification of the cases as class actions, compensatory damages, reasonable costs and expenses, including counsel fees, and rescission damages.

The Southern District of New York granted the defendants motion to transfer the two securities class actions filed in Maryland to the District of Maryland, and the actions have since been transferred for coordination with the securities class action filed there. On May 9, 2013, the federal court in Maryland preliminarily approved the settlement of Constellation s 2008 Securities Class Action for a payment of $4 million, which will be paid by Constellation s insurer. Notice of the settlement was provided to class members in June 2013 and the court approved the final settlement on November 4, 2013. This settlement will resolve all of Constellation s litigation arising from the 2008 Securities Class Action lawsuit.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Baltimore City Franchise Taxes (BGE)

The City of Baltimore claims that BGE has maintained electric facilities in the City s public right-of-ways for over one hundred years without the proper franchise rights from the City. BGE is currently reviewing the merits of this claim. The Company 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 (Exelon, Generation, ComEd, PECO and BGE)

The Registrants are involved in various other litigation matters that are being defended and handled in the ordinary course of business. The assessment of whether a loss is probable or a reasonable possibility, and whether the loss or a range of loss is estimable, often involves a series of complex judgments about future events. The Registrants maintain accruals for 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 (Exelon, Generation, ComEd, PECO and BGE)

See Note 12 Income Taxes for information regarding the Registrants income tax refund claims and certain tax positions, including the 1999 sale of fossil generating assets.

19. Supplemental Financial Information (Exelon, Generation, ComEd, PECO and BGE)

Supplemental Statement of Operations Information

The following tables provide additional information about the Registrants Consolidated Statements of Operations and Comprehensive Income for the three and nine months ended September 30, 2013 and 2012:

Three Months Ended September 30, 2013	**Exelon**	**Generation**	**ComEd**	**PECO**	**BGE**
Other, Net					
Decommissioning-related activities:					
Net realized income on decommissioning trust funds(a)					
Regulatory agreement units	$ 138	$ 138	$	$	$
Non-regulatory agreement units	35	35			
Net unrealized gains on decommissioning trust funds					
Regulatory agreement units	103	103			
Non-regulatory agreement units	46	46			
Net unrealized losses on pledged assets					
Zion Station decommissioning	(9)	(9)			
Regulatory offset to decommissioning trust fund-related activities(b)	(189)	(189)			
Total decommissioning-related activities	124	124			
Investment income	1				2(c)
Long-term lease income	7				
AFUDC Equity	4		2	1	1
Other	19	10	5		1
Other, net	$ 155	$ 134	$ 7	$ 1	$ 4

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Nine Months Ended September 30, 2013	Exelon	Generation	ComEd	PECO	BGE
Other, Net					
Decommissioning-related activities:					
Net realized income on decommissioning trust funds(a)					
Regulatory agreement units	$ 221	$ 221	$	$	$
Non-regulatory agreement units	65	65			
Net unrealized gains on decommissioning trust funds					
Regulatory agreement units	196	196			
Non-regulatory agreement units	70	70			
Net unrealized losses on pledged assets					
Zion Station decommissioning	(5)	(5)			
Regulatory offset to decommissioning trust fund-related activities(b)	(338)	(338)			
Total decommissioning-related activities	209	209			
Investment income (expense)	6	(1)		(1)	7(c)
Long-term lease income	20				
Interest income related to uncertain income tax positions	24	3		1	
AFUDC Equity	16		8	3	5
Other	36	18	10	1	1
Other, net	$ 311	$ 229	$ 18	$ 4	$ 13

Three Months Ended September 30, 2012	Exelon	Generation	ComEd	PECO	BGE
Other, Net					
Decommissioning-related activities:					
Net realized income on decommissioning trust funds(a)					
Regulatory agreement units	$ 33	$ 33	$	$	$
Non-regulatory agreement units	10	10			
Net unrealized gains on decommissioning trust funds					
Regulatory agreement units	202	202			
Non-regulatory agreement units	71	71			
Net unrealized gains on pledged assets					
Zion Station decommissioning	22	22			
Regulatory offset to decommissioning trust fund-related activities(b)	(208)	(208)			
Total decommissioning-related activities	130	130			
Investment income	5	1			3
Long-term lease income	7				
Interest income related to uncertain income tax positions		1	1		
Credit facility termination fees	(43)	(43)			
AFUDC Equity	4		1	1	2
Other	(2)	(6)	3	1	
Other, net	$ 101	$ 83	$ 5	$ 2	$ 5

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Nine Months Ended September 30, 2012	Exelon	Generation	ComEd	PECO	BGE
Other, Net					
Decommissioning-related activities:					
Net realized income on decommissioning trust funds(a)					
Regulatory agreement units	$ 143	$ 143	$	$	$
Non-regulatory agreement units	77	77			
Net unrealized gains on decommissioning trust funds					
Regulatory agreement units	352	352			
Non-regulatory agreement units	101	101			
Net unrealized gains on pledged assets					
Zion Station decommissioning	60	60			
Regulatory offset to decommissioning trust fund-related activities(b)	(453)	(453)			
Total decommissioning-related activities	280	280			
Investment income	15	2	1	2	9
Long-term lease income	22				
Interest income related to uncertain income tax positions	14	1	1		
Credit facility termination fees	(85)	(85)			
AFUDC Equity	11		2	3	8
Other	(4)	(13)	8	1	1
Other, net	$ 253	$ 185	$ 12	$ 6	$ 18

(a) Includes investment income and realized gains and losses on sales of investments of the trust funds.
(b) Includes the elimination of NDT fund-related activity for the Regulatory Agreement Units, including the elimination of net income taxes related to all NDT fund activity for those units. See Note 13 Asset Retirement Obligations of the Exelon 2012 Form 10-K for additional information regarding the accounting for nuclear decommissioning.
(c) Relates to the cash return on BGE s rate stabilization deferral. See Note 5 Regulatory Matters for additional information regarding the rate stabilization deferral.

Supplemental Cash Flow Information

The following tables provide additional information regarding the Registrants Consolidated Statements of Cash Flows for the nine months ended September 30, 2013 and 2012:

Nine Months Ended September 30, 2013	Exelon	Generation	ComEd	PECO	BGE
Depreciation, amortization, accretion and depletion					
Property, plant and equipment	$ 1,420	$ 610	$ 413	$ 164	$ 194
Regulatory assets	153		88	7	58
Amortization of intangible assets, net	33	33			
Amortization of energy contract assets and liabilities(a)	342	398			
Nuclear fuel(a)	689	689			
ARO accretion(b)	207	207			
Total depreciation, amortization, accretion and depletion	$ 2,844	$ 1,937	$ 501	$ 171	$ 252

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Nine Months Ended September 30, 2012	Exelon	Generation	ComEd	PECO	BGE
Depreciation, amortization, accretion and depletion					
Property, plant and equipment	$ 1,263	$ 540	$ 396	$ 154	$ 184
Regulatory assets	89		62	7	34
Amortization of intangible assets, net	24	24			
Amortization of energy contract assets and liabilities(a)	731	812			
Nuclear fuel(a)	628	628			
ARO accretion(b)	174	174			
Total depreciation, amortization, accretion and depletion	$ 2,909	$ 2,178	$ 458	$ 161	$ 218

(a) Included in revenues or fuel expense, or operating revenues on the Registrants Consolidated Statements of Operations and Comprehensive Income.
(b) Included in operating and maintenance expense on the Registrants Consolidated Statements of Operations.

Nine Months Ended September 30, 2013	Exelon	Generation	ComEd	PECO	BGE
Other non-cash operating activities:					
Pension and non-pension postretirement benefit costs	$ 621	$ 259	$ 231	$ 32	$ 41
Loss in equity method investments	(7)	(7)			
Provision for uncollectible accounts	83	16	(6)	48	25
Stock-based compensation costs	99				
Other decommissioning-related activity(a)	(110)	(110)			
Energy-related options(b)	87	87			
Amortization of regulatory asset related to debt costs	9		7	2	
Amortization of rate stabilization deferral	49				49
Amortization of debt fair value adjustment	(28)	(28)			
Discrete impacts from EIMA(c)	(206)		(206)		
Amortization of debt costs	13	7	3	2	1
Merger integration costs(d)	(6)				(6)
Impairment of investments in direct financing leases(e)	14				
Increase in inventory reserve	7	7			
Impairment charges(f)	149	149			
Other	(36)	(5)	(3)		(5)
Total other non-cash operating activities	$ 738	$ 375	$ 26	$ 84	$ 105
Changes in other assets and liabilities:					
Under/over-recovered energy and transmission costs	$ (47)	$	$ (63)	$ (10)	$ 26
Other regulatory assets and liabilities	(50)		(35)		(85)
Settlement of interest rate swaps(j)	26				
Other current assets	(169)	(123)	(3)	(31)	(35)
Other noncurrent assets and liabilities	205	(40)	261(g)	(6)	(25)
Total changes in other assets and liabilities	$ (35)	$ (163)	$ 160	$ (47)	$ (119)
Non-cash investing and financing activities:					
Consolidated VIE dividend to non-controlling interest	$ 63	$ 63	$	$	$
Indemnification of like-kind exchange position(h)			175		

Total non-cash investing and financing activities:	$ 63	$ 63	$ 175	$	$

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Nine Months Ended September 30, 2012	Exelon	Generation	ComEd	PECO	BGE
Other non-cash operating activities:					
Pension and non-pension postretirement benefit costs	$ 606	$ 259	$ 212	$ 38	$ 44
Provision for uncollectible accounts	120	14	38	46	28
Stock-based compensation costs	75				
Other decommissioning-related activity(a)	(108)	(108)			
Energy-related options(b)	119	119			
Amortization of regulatory asset related to debt costs	13		10	2	1
Amortization of rate stabilization deferral	39				49
Amortization of debt fair value adjustment	(49)	(23)			
Discrete impacts from EIMA(c)	43		43		
Merger-related commitments(i)	179	35			28
Severance cost	120	34		1	
Loss in equity method investments	69	69			
Other	9	23	7	9	(2)
Total other non-cash operating activities	$ 1,235	$ 422	$ 310	$ 96	$ 148
Changes in other assets and liabilities:					
Under/over-recovered energy and transmission costs	$ 20	$	$ 21	$ (3)	$ 21
Other regulatory assets and liabilities	(454)		(65)	7	(80)
Other current assets	52	(85)	(8)	(56)	(25)
Other noncurrent assets and liabilities	(40)	(110)	(72)	(5)	7
Total changes in other assets and liabilities	$ (422)	$ (195)	$ (124)	$ (57)	$ (77)
Non-cash investing and financing activities:					
Merger with Constellation, common stock issued	$ 7,365	$ 5,258	$	$	$

(a) Includes the elimination of NDT fund-related 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 13 of the Exelon 2012 Form 10-K 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 5 Regulatory Matters for more information.
(d) Relates to integration costs to achieve distribution synergies related to the merger transaction. See Note 5 Regulatory Matters for more information.
(e) Relates to an other than temporary decline in the estimated residual value of one of Exelon s direct financing leases. See Note 7 Impairment of Long-Lived Assets for more information.
(f) Relates to the cancellation of uprate projects and write down of certain wind projects at Generation. See Note 7 Impairment of Long-Lived Assets for additional information.
(g) Relates primarily to interest payable related to like-kind exchange tax position. See Note 12 Income Taxes for discussion of the like-kind exchange tax position.
(h) See Note 12 Income Taxes for discussion of the like-kind exchange tax position.
(i) See Note 4 Mergers and Acquisitions for more information on merger-related commitments.
(i) Relates to settlement of forward starting interest rate swaps that Exelon entered into in anticipation of the Continental Wind, LLC non-recourse project financing that was completed on September 30, 2013. See Note 10 Derivative Financial Instruments for more information on interest rate swaps.

DOE Smart Grid Investment Grant (Exelon, PECO and BGE). For the nine months ended September 30, 2013, Exelon, PECO and BGE have included in the Capital expenditures line item under investing activities of

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

the cash flow statement capital expenditures of $68 million, $22 million and $46 million, respectively, and reimbursements of $64 million, $30 million and $34 million, respectively, related to PECO's and BGE's DOE SGIG programs. For the nine months ended September 30, 2012, Exelon, PECO and BGE have included in the Capital expenditures line item under investing activities of the cash flow statement capital expenditures of $75 million, $45 million and $30 million, respectively, and reimbursements of $85 million, $55 million and $30 million, respectively, related to PECO's and BGE's DOE SGIG programs. See Note 5 - Regulatory Matters for additional information regarding the DOE SGIG.

Supplemental Balance Sheet Information

The following tables provide additional information about assets and liabilities of the Registrants as of September 30, 2013 and December 31, 2012.

September 30, 2013	**Exelon**	**Generation**	**ComEd**	**PECO**	**BGE**
Property, plant and equipment:					
Accumulated depreciation and amortization	$ 13,366(a)	$ 6,848(a)	$ 3,107	$ 2,914	$ 2,658
Accounts receivable:					
Allowance for uncollectible accounts	302	72	73	119	38

December 31, 2012	**Exelon**	**Generation**	**ComEd**	**PECO**	**BGE**
Property, plant and equipment:					
Accumulated depreciation and amortization	$ 12,184(b)	$ 6,014(b)	$ 2,998	$ 2,797	$ 2,595
Accounts receivable:					
Allowance for uncollectible accounts	293	84	70	99	40

(a) Includes accumulated amortization of nuclear fuel in the reactor core of $2,365 million.
(b) Includes accumulated amortization of nuclear fuel in the reactor core of $2,078 million.

PECO Installment Plan Receivables (Exelon and PECO)

PECO enters into payment agreements with certain delinquent customers, primarily residential, seeking to restore their service, as required by the PAPUC. Customers with past due balances that meet certain income criteria are provided the option to enter into an installment payment plan, some of which have terms greater than one year, to repay past due balances in addition to paying for their ongoing service on a current basis. The receivable balance for these payment agreement receivables is recorded in accounts receivable for the current portion and other deferred debits and other assets for the noncurrent portion. The net receivable balance for installment plans with terms greater than one year was $22 million as of September 30, 2013 and $18 million as of December 31, 2012. 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 Account Policies of the Exelon 2012 Form 10-K. The allowance for uncollectible accounts balance associated with these receivables at September 30, 2013 of $22 million consists of $1 million, $4 million and $17 million for low risk, medium risk and high risk segments, respectively. The allowance for uncollectible accounts balance at December 31, 2012 of $15 million consists of $1 million, $3 million and $11 million for low risk, medium risk and high risk segments, respectively. The balance of the payment agreement is billed to the customer in equal monthly installments over the term of the agreement. Installment receivables outstanding as of September 30, 2013 and December 31, 2012 include balances not yet presented on the customer bill, accounts currently billed and an immaterial amount of past due receivables. When a customer defaults on its payment agreement, the terms of which are defined by plan type, the entire balance of the agreement becomes due and the balance is reclassified to current customer accounts receivable and reserved for in accordance with the methodology discussed in Note 1 Significant Accounting Policies of the Exelon 2012 Form 10-K.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

20. Segment Information (Exelon, Generation, ComEd, PECO and BGE)

Exelon has nine reportable segments, ComEd, PECO, BGE and Generation s six power marketing reportable segments consisting of the Mid-Atlantic, Midwest, New England, New York, ERCOT and all other regions not considered individually significant referred to collectively as Other Regions ; including the South, West and Canada. Generation s expanded number of reportable segments is the result of the acquisition of Constellation on March 12, 2012. ComEd, PECO and BGE each represent a single reportable segment; as such, no separate segment information is provided for these Registrants. Exelon evaluates the performance of ComEd, PECO and BGE based on net income.

The 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 entire United States footprint of MISO, 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 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.

Exelon and Generation evaluate the performance of Generation s power marketing activities based on revenue net of purchased power and fuel expense. Generation believes that revenue net of purchased power and fuel expense is a useful measurement of operational performance. Revenue net of purchased power and fuel expense is not a presentation defined under GAAP and may not be comparable to other companies presentations or deemed more useful than the GAAP information provided elsewhere in this report. Generation s operating revenues include all sales to third parties and affiliated sales to ComEd, PECO and BGE. Purchased power costs include all costs associated with the procurement and supply of electricity including capacity, energy and ancillary services. Fuel

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

expense includes the fuel costs for Generation s own generation and fuel costs associated with tolling agreements. Generation's other business activities, including retail and wholesale gas, upstream natural gas, proprietary trading, energy efficiency and demand response, heating, cooling, and cogeneration facilities, and home improvements, sales of electric and gas appliances, servicing of heating, air conditioning, plumbing, electrical, and indoor quality systems, and investments in energy-related proprietary technology are not allocated to regions. Further, Generation s compensation under the reliability-must-run rate schedule, results of operations from the Brandon Shores, Wagner, and C.P. Crane Maryland generating stations, and other miscellaneous revenues, mark-to-market impact of economic hedging activities, and amortization of certain intangible assets relating to commodity contracts recorded at fair value as a result of the merger are also not allocated to a region.

An analysis and reconciliation of the Registrants reportable segment information to the respective information in the consolidated financial statements for the three and nine months ended September 30, 2013 and 2012 is as follows:

Three Months Ended September 30, 2013 and 2012

	Generation(a)	ComEd	PECO	BGE	Other(b)	Intersegment Eliminations	Exelon
Total revenues(c):							
2013	$ 4,255	$ 1,156	$ 728	$ 737	$ 294	$ (668)	$ 6,502
2012	4,031	1,484	806	720	336	(798)	6,579
Intersegment revenues(d):							
2013	$ 373	$ 1	$ 1	$ 2	$ 294	$ (669)	$ 2
2012	459		1	4	337	(798)	3
Net income (loss):							
2013	$ 485	$ 126	$ 92	$ 53	$ (20)	$	$ 736
2012	87	90	123		(3)		297
Total assets:							
September 30, 2013	$ 40,498	$ 23,686	$ 9,745	$ 7,657	$ 9,563	$ (11,488)	$ 79,661
December 31, 2012	40,681	22,905	9,353	7,506	10,432	(12,316)	78,561

(a) Generation includes the six power marketing reportable segments shown below: Mid-Atlantic, Midwest, New England, New York, ERCOT and Other Regions. Intersegment revenues for Generation for the three months ended September 30, 2013 include revenue from sales to PECO of $82 million and sales to BGE of $144 million in the Mid-Atlantic region, and sales to ComEd of $143 million in the Midwest. For the three months ended September 30, 2012 intersegment revenues for Generation include revenue from sales to PECO of $171 million and sales to BGE of $120 million in the Mid-Atlantic region, and sales to ComEd of $180 million in the Midwest region, net of $15 million related to the unrealized mark-to-market losses related to the ComEd swap, which eliminate upon consolidation.

(b) Other primarily includes Exelon's corporate operations, shared service entities and other financing and investment activities.

(c) For the three months ended September 30, 2013 and 2012, utility taxes of $21 million and $28 million, respectively, are included in revenues and expenses for Generation. For the three months ended September 30, 2013 and 2012, utility taxes of $65 million and $67 million, respectively, are included in revenues and expenses for ComEd. For the three months ended September 30, 2013 and 2012, utility taxes of $33 million and $40 million, respectively, are included in revenues and expenses for PECO. For the three months ended September 30, 2013 and 2012, utility taxes of $20 million and $20 million, respectively, are included in revenues and expenses for BGE.

(d) Intersegment revenues exclude sales to unconsolidated affiliate entities. 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 Statements of Operations.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Generation total revenues (three months ended):

	2013			2012		
	Revenues from external customers(a)	Intersegment revenues	Total Revenues	Revenues from external customers(a)	Intersegment revenues	Total Revenues
Mid-Atlantic	$ 1,381	$ 10	$ 1,391	$ 1,428	$ (11)	$ 1,417
Midwest	1,018	(5)	1,013	1,193	7	1,200
New England	341	(1)	340	390	1	391
New York	198	(14)	184	183	2	185
ERCOT	430	(3)	427	532	1	533
Other Regions(b)	278	(7)	271	317	12	329
Total Revenues for Reportable Segments	3,646	(20)	3,626	4,043	12	4,055
Other(c)	609	20	629	(12)	(12)	(24)
Total Generation Consolidated Operating Revenues	$ 4,255	$	$ 4,255	$ 4,031	$	$ 4,031

(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 $125 million and $404 million, for the three months ended September 30, 2013 and 2012, respectively, and elimination of intersegment revenues.

Generation total revenues net of purchased power and fuel expense (three months ended):

	2013			2012		
	RNF from external customers(a)	Intersegment RNF	Total RNF	RNF from external customers(a)	Intersegment RNF	Total RNF
Mid-Atlantic	$ 857	$ 7	$ 864	$ 919	$ (11)	$ 908
Midwest	606	(5)	601	723	7	730
New England	52	10	62	80	1	81
New York	29	(38)	(9)	11	2	13
ERCOT	222	(78)	144	158		158
Other Regions(b)	116	(75)	41	30	12	42
Total Revenues net of purchased power and fuel expense for Reportable Segments	1,882	(179)	1,703	1,921	11	1,932
Other(c)	194	179	373	(12)	(11)	(23)
Total Generation Revenues net of purchased power and fuel expense	$ 2,076	$	$ 2,076	$ 1,909	$	$ 1,909

(a) Includes purchases and sales from third parties and affiliated sales to ComEd, PECO and BGE.
(b) Other regions includes 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 $44 million and $257 million for the three months ended September 30, 2013 and 2012, respectively.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Nine Months Ended September 30, 2013 and 2012

	Generation(a)	ComEd	PECO	BGE(b)	Other(c)	Intersegment Eliminations	Exelon
Total revenues(d):							
2013	$ 11,858	$ 3,395	$ 2,295	$ 2,271	$ 909	$ (2,003)	$ 18,725
2012	10,539	4,154	2,396	1,388	1,049	(2,291)	17,235
Intersegment revenues(e):							
2013	$ 1,083	$ 2	$ 1	$ 10	$ 909	$ (2,003)	$ 2
2012	1,233	2	3	7	1,050	(2,291)	4
Net income (loss):							
2013	$ 795	$ 140	$ 292	$ 160	$ (152)	$	$ 1,235
2012	419	219	300	(50)	(101)		787

(a) Generation includes the six power marketing reportable segments shown below: Mid-Atlantic, Midwest, New England, New York, ERCOT and Other Regions. Intersegment revenues for Generation for the nine months ended September 30, 2013 include revenue from sales to PECO of $321 million and sales to BGE of $356 million in the Mid-Atlantic region, and sales to ComEd of $409 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 nine months ended September 30, 2012 intersegment revenues for Generation include revenue from sales to PECO of $407 million in the Mid-Atlantic region and sales to BGE of $223 million in the Mid-Atlantic region, and sales to ComEd of $631 million in the Midwest region, net of $30 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 September 30, 2012.

(c) Other primarily includes Exelon s corporate operations, shared service entities and other financing and investment activities.

(d) For the nine months ended September 30, 2013 and 2012, utility taxes of $60 million and $60 million, respectively, are included in revenues and expenses for Generation. For the nine months ended September 30, 2013 and 2012, utility taxes of $182 million and $182 million, respectively, are included in revenues and expenses for ComEd. For the nine months ended September 30, 2013 and 2012, utility taxes of $97 million and $108 million, respectively, are included in revenues and expenses for PECO. For the nine months ended September 30, 2013 and period of March 12, 2012 through September 30, 2012, utility taxes of $62 million and $42 million, respectively, are included in revenues and expenses for BGE.

(e) Intersegment revenues exclude sales to unconsolidated affiliate entities. 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 Statements of Operations.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Generation total revenues (nine months ended):

	2013			2012		
	Revenues from external customers(a)	Intersegment revenues	Total Revenues	Revenues from external customers(a)	Intersegment revenues	Total Revenues
Mid-Atlantic	$ 3,932	$ 11	$ 3,943	$ 3,832	$ (43)	$ 3,789
Midwest	3,274	(3)	3,271	3,600	19	3,619
New England	942	(9)	933	776	36	812
New York	547	(20)	527	394	(22)	372
ERCOT	1,042	(8)	1,034	1,073	1	1,074
Other Regions(b)	708	29	737	611	40	651
Total Revenues for Reportable Segments	10,445		10,445	10,286	31	10,317
Other(c)	1,413		1,413	253	(31)	222
Total Generation Consolidated Operating Revenues	$ 11,858	$	$ 11,858	$ 10,539	$	$ 10,539

(a) Includes all wholesale and retail electric 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 at the merger date of $603 million and $1,089 million, for the nine months ended September 30, 2013 and 2012, respectively, and elimination of intersegment revenues.

Generation total revenues net of purchased power and fuel expense (nine months ended):

	2013			2012		
	RNF from external customers(a)	Intersegment RNF	Total RNF	RNF from external customers(a)	Intersegment RNF	Total RNF
Mid-Atlantic	$ 2,477	$ (2)	$ 2,475	$ 2,605	$ (44)	$ 2,561
Midwest	2,002	(1)	2,001	2,291	19	2,310
New England	156	(14)	142	144	36	180
New York	14	(31)	(17)	82	(22)	60
ERCOT	477	(120)	357	311	1	312
Other Regions(b)	238	(91)	147	49	41	90
Total Revenues net of purchased power and fuel expense for Reportable Segments	5,364	(259)	5,105	5,482	31	5,513
Other(c)	200	259	459	39	(31)	8
	$ 5,564	$	$ 5,564	$ 5,521	$	$ 5,521

Total Generation Revenues net of purchased power and fuel expense	

(a) Includes purchases and sales from third parties and affiliated sales to ComEd, PECO and BGE.
(b) Other regions includes 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 at the merger date of $386 million and $793 million, for the nine months ended September 30, 2013 and 2012, respectively.

Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations

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

Exelon Corporation

General

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

Generation, one of the largest competitive electric generation companies in the United States as measured by owned and contracted MW, physically delivers and markets power across multiple geographic regions through its customer-facing business, Constellation. Generation operates as an integrated business, leveraging its owned and contracted electric generation capacity to market and sell power to wholesale and retail supply customers. Generation s customers include distribution utilities, municipalities, cooperatives, financial institutions, and commercial, industrial, governmental, and residential customers in competitive markets. Generation also sells natural gas and renewable and other energy-related offerings, and engages in natural gas exploration and production activities.

ComEd, whose business consists of the purchase and regulated retail sale of electricity and the provision of distribution and transmission services in northern Illinois, including the City of Chicago.

PECO, whose business consists of the purchase and regulated retail sale of electricity and the provision of distribution and transmission services in southeastern Pennsylvania, including the City of Philadelphia, and the purchase and regulated retail sale of natural gas and the provision of distribution services in the Pennsylvania counties surrounding the City of Philadelphia.

BGE, whose business consists of the purchase and regulated retail sale of electricity and the provision of distribution and transmission services in central Maryland, including the City of Baltimore, and the purchase and regulated retail sale of natural gas and the provision of distribution services in central Maryland, including the City of Baltimore.

Exelon has nine reportable segments consisting of Generation s six power marketing reportable segments (Mid-Atlantic, Midwest, New England, New York, ERCOT and other regions in Generation), ComEd, PECO and BGE. See Note 20 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.

Executive Overview

Financial Results. The following consolidated financial results reflect the results of Exelon for the three and nine months ended September 30, 2013 compared to the corresponding periods in 2012. The financial results for the nine months ended September 30, 2012 only include the operations of Constellation and BGE from March 12, 2012, the date of the merger with Constellation, through September 30, 2012. All amounts presented below are before the impact of income taxes, except as noted.

	Three Months Ended September 30, 2013						2012	Favorable (Unfavorable)
	Generation	**ComEd**	**PECO**	**BGE**	**Other**	**Exelon**	**Exelon**	**Variance**
Operating revenues	$ 4,255	$ 1,156	$ 728	$ 737	$ (374)	$ 6,502	$ 6,579	$ (77)
Purchased power and fuel	2,179	301	289	346	(372)	2,743	3,026	283
Revenue net of purchased power and fuel(a)	2,076	855	439	391	(2)	3,759	3,553	206
Other operating expenses								
Operating and maintenance	1,076	333	186	146	(6)	1,735	2,170	435
Depreciation and amortization	218	164	57	78	13	530	500	(30)
Taxes other than income	98	80	41	53	5	277	290	13
Total other operating expenses	1,392	577	284	277	12	2,542	2,960	418
Equity in earnings of unconsolidated affiliates	37					37	10	27
Operating income (loss)	721	278	155	114	(14)	1,254	603	651
Other income and (deductions)								
Interest expense, net	(82)	(74)	(29)	(29)	(20)	(234)	(246)	12
Other, net	134	7	1	4	9	155	101	54
Total other income and (deductions)	52	(67)	(28)	(25)	(11)	(79)	(145)	66
Income (loss) before income taxes	773	211	127	89	(25)	1,175	458	717
Income taxes	288	85	35	36	(5)	439	161	(278)
Net income (loss)	485	126	92	53	(20)	736	297	439
Net (loss) income attributable to noncontrolling interests, preferred security dividends and redemption and preference stock dividends	(5)			3		(2)	1	3
Net income (loss) attributable to common shareholders	$ 490	$ 126	$ 92	$ 50	$ (20)	$ 738	$ 296	$ 442

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	Nine Months Ended September 30, 2013						2012	Favorable (Unfavorable)
	Generation	ComEd	PECO	BGE	Other	Exelon	Exelon	Variance
Operating revenues	$ 11,858	$ 3,395	$ 2,295	$ 2,271	$ (1,094)	$ 18,725	$ 17,235	$ 1,490
Purchased power and fuel	6,294	931	953	1,059	(1,094)	8,143	7,398	(745)
Revenue net of purchased power and fuel(a)	5,564	2,464	1,342	1,212		10,582	9,837	745
Other operating expenses								
Operating and maintenance	3,377	1,020	554	450	(10)	5,391	5,979	588
Depreciation and amortization	643	501	171	252	39	1,606	1,376	(230)
Taxes other than income	292	225	121	162	25	825	737	(88)
Total other operating expenses	4,312	1,746	846	864	54	7,822	8,092	270
Equity in earnings (loss) of unconsolidated affiliates	7					7	(69)	76
Operating income (loss)	1,259	718	496	348	(54)	2,767	1,676	1,091
Other income and (deductions)								
Interest expense, net	(257)	(503)	(86)	(94)	(170)	(1,110)	(697)	(413)
Other, net	229	18	4	13	47	311	253	58
Total other income and (deductions)	(28)	(485)	(82)	(81)	(123)	(799)	(444)	(355)
Income (loss) before income taxes	1,231	233	414	267	(177)	1,968	1,232	736
Income taxes	436	93	122	107	(25)	733	445	(288)
Net income (loss)	795	140	292	160	(152)	1,235	787	448
Net (loss) income attributable to noncontrolling interests, preferred security dividends and redemption and preference stock dividends	(6)		7	10		11	5	(6)
Net income (loss) attributable to common shareholders	$ 801	$ 140	$ 285	$ 150	$ (152)	$ 1,224	$ 782	$ 442

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

Three Months Ended September 30, 2013 Compared to Three Months Ended September 30, 2012. Exelon s net income attributable to common shareholders was $738 million for the three months ended September 30, 2013 as compared to net income attributable to common shareholders of $296 million for the three months ended September 30, 2012, and diluted earnings per average common share were $0.86 for the three months ended September 30, 2013 as compared to $0.35 for the three months ended September 30, 2012.

Operating revenue net of purchased power and fuel expense, which is a non-GAAP measure discussed below, increased by $206 million for the three months ended September 30, 2013 as compared to the same period in 2012. The year-over-year increase in operating revenue net of purchased power and fuel expense was primarily due to the following favorable factors:

- Increase in Generation s mark-to-market gains from economic hedging activities of $229 million, higher capacity revenue of $124 million, and a decrease in Generation s amortization expense for the acquired energy contracts recorded at fair value at the merger date of $213 million;

- Increase in ComEd s revenue net of purchased power expense of $49 million primarily due to increased distribution revenue due to increased costs and capital investment and higher allowed ROE pursuant to the formula rate under EIMA and the enactment of Senate Bill 9; and

- Increase in BGE s revenue net of purchased power and fuel expense of $44 million primarily due to the impact of the new electric and natural gas distribution rates charged to customers that became effective February 23, 2013 in accordance with the 2012 MDPSC approved electric and natural gas distribution rate case order, and increased cost recovery for energy efficiency and demand response programs.

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

- Decrease in Generation s electric revenue net of purchased power and fuel expense of $355 million primarily due to lower realized energy prices, lower load volume, and increased nuclear fuel expense, partially offset by increased nuclear volumes and lower energy supply costs as a result of the integration of the energy generation and load serving businesses following the merger;

- Decrease in PECO s revenue net of purchased power and fuel expense of $41 million primarily due to decreased cost recovery for energy efficiency and demand response programs; and

- Reduced margin at Generation of $44 million in 2013 associated with the Maryland Clean Coal assets that were sold in November 2012.

Operating and maintenance expense decreased by $435 million for the three months ended September 30, 2013 as compared to the same period in 2012 primarily due to the following favorable factors:

- Decrease in operating and maintenance expense associated with the generating assets retired or divested during 2012 of $337 million; and

- Decrease in labor, contracting and materials costs of $36 million primarily due to realized merger synergy savings at Exelon s corporate operations and shared service entities and at Generation, partially offset by the impact of inflation across all operating companies; and

- Decrease in uncollectible accounts expense of $28 million at ComEd resulting from the timing of regulatory cost recovery and customers purchasing electricity from competitive electric generation suppliers.

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

Long-lived asset impairment and related charges of $46 million in the third quarter of 2013, primarily related to certain wind generating assets at Generation; and

Increased merger and integration costs of $32 million at Constellation.

Depreciation and amortization expense increased by $30 million primarily due to ongoing capital expenditures across the operating companies, wind and solar facilities placed into service in the second half of 2012 and in 2013 at Generation, and higher costs for energy efficiency and demand response programs at BGE.

Equity in earnings of unconsolidated affiliates increased by $27 million primarily due to higher net income from Generation s equity investment in CENG in the third quarter of 2013 compared to the same period in 2012 and lower amortization of the basis difference of Generation s ownership interest in CENG recorded at fair value in connection with the merger.

Exelon s effective income tax rates for the three months ended September 30, 2013 and 2012 were 37.4% and 35.2%, respectively. See Note 12 Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

Nine Months Ended September 30, 2013 Compared to Nine Months Ended September 30, 2012. Exelon s net income attributable to common shareholders was $1,224 million for the nine months ended September 30, 2013 as compared to net income attributable to common shareholders of $782 million for the nine months ended September 30, 2012, and diluted earnings per average common share were $1.42 for the nine months ended September 30, 2013 as compared to $0.97 for the nine months ended September 30, 2012.

Operating revenue net of purchased power and fuel expense, which is a non-GAAP measure discussed below, increased by $745 million for the nine months ended September 30, 2013 as compared to the same period in 2012. The year-over-year increase in operating revenue net of purchased power and fuel expense was primarily due to the following favorable factors:

- Increase in BGE s revenue net of purchased power and fuel expense of $223 million, primarily as a result of the inclusion of BGE s results for the full period in 2013, accrual of the residential customer rate credit that was a condition of the MDPSC s approval of Exelon s merger with Constellation in 2012, and the impact of the new electric and natural gas distribution rates charged to customers that became effective February 23, 2013 in accordance with the 2012 MDPSC approved electric and natural gas distribution rate case order;

- Increase in Generation s net margin of $174 million on other activities, including proprietary trading, retail gas, energy efficiency, energy management and demand response, upstream natural gas and the design and construction of customer sited solar facilities, primarily due to the addition of Constellation;

- Decrease in Generation s amortization expense for the acquired energy contracts recorded at fair value at the merger date of $407 million; and

- Increase in ComEd s revenue net of purchased power expense of $196 million primarily due to the discrete impacts of the ICC s May 2012 Order in ComEd s 2011 formula rate proceeding under EIMA, increased distribution revenue as a result of increased costs and capital investment and higher allowed ROE pursuant to the formula rate under EIMA and the enactment of Senate Bill 9;

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

- Decrease in PECO s revenue net of purchased power and fuel expense of $21 million primarily due to the decrease in effective rates due to increased usage per customer across all customer classes, decreased cost recovery for energy efficiency and demand response programs, a decrease in gross receipts tax revenue, and the customer refund in 2013 of the tax cash benefit related to gas property distribution repairs;

- Decrease in Generation s electric revenue net of purchased power and fuel expense of $408 million primarily due to lower realized energy prices, lower load volume and increased nuclear fuel expense, partially offset by higher capacity revenue, increased nuclear volumes, and lower energy supply costs as a result of the integration of the energy generation and load serving businesses following the merger; and

Reduced margin at Generation of $125 million in 2013 associated with the Maryland Clean Coal assets that were sold in November 2012 and lost compensation on the reliability-must-run program with PJM for retired fossil generating assets that expired on May 31, 2012.

Operating and maintenance expense decreased by $588 million for the nine months ended September 30, 2013 as compared to the same period in 2012 primarily due to the following favorable factors:

- Decrease in operating and maintenance expense associated with the generating assets retired or divested during 2012 of $392 million;
- Costs incurred in March 2012 of $216 million and $195 million as part of the Maryland order approving the merger and a settlement with the FERC, respectively;
- Decrease in Constellation merger and integration costs of $150 million in 2013; and
- Decrease in uncollectible accounts expense of $43 million at ComEd resulting from the timing of regulatory cost recovery and customers purchasing electricity from competitive electric generation suppliers.

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

- Increase in labor, other benefits, contracting and materials costs of $224 million and an increase in pension and non-pension postretirement benefit expenses of $25 million, primarily due to the addition of BGE and Constellation for the full period in 2013; and
- Long-lived asset impairments and related charges of $172 million in 2013, primarily related to Generation s cancellation of nuclear uprate projects and the impairment of certain wind generating assets.

Depreciation and amortization expense increased by $230 million primarily due to higher plant balances resulting from the addition of BGE s and Constellation s plant balances in 2012, ongoing capital expenditures across the operating companies, the completion of wind and solar facilities placed into service in the second half of 2012 and in 2013 at Generation, and increased regulatory asset amortization related to higher MGP remediation expenditures and higher costs for energy efficiency and demand response programs at ComEd and BGE, respectively.

The favorable increase in Equity in earnings/loss of unconsolidated affiliates of $76 million was primarily due to higher net income from Generation s equity investment in CENG in 2013 compared to the same period in 2012 and lower amortization of the basis difference of Generation s ownership interest in CENG recorded at fair value in connection with the merger.

Interest expense increased by $413 million primarily due to an increase in interest expense at ComEd related to the remeasurement of Exelon s like-kind exchange tax position in the first quarter of 2013, an increase in debt obligations as a result of the merger and an increase in debt issued at Generation in June 2012.

Exelon s effective income tax rates for the nine months ended September 30, 2013 and September 30, 2012 were 37.2% and 36.1%, respectively. See Note 12 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 three and nine months ended September 30, 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 three months ended September 30, 2013 were $667 million, or $0.78 per diluted share, compared with adjusted (non-GAAP) operating earnings of $658 million, or $0.77 per diluted share, for the same period in 2012. Exelon s adjusted (non-GAAP) operating earnings for the nine months ended September 30, 2013 were $1,722 million, or $2.00 per diluted share, compared with adjusted (non-GAAP) operating earnings of $1,783 million, or $2.21 per diluted share, for the same period in 2012. In addition to net income attributable to common

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shareholders, 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. 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 three and nine months ended September 30, 2013 as compared to the same period in 2012:

	Three Months Ended September 30,			
	2013		2012	
(All amounts after tax)		**Earnings per Diluted Share**		**Earnings per Diluted Share**
Net Income Attributable to Common Shareholders	$ 738	$ 0.86	$ 296	$ 0.35
Mark-to-Market Impact of Economic Hedging Activities(a)	(148)	(0.17)	(19)	(0.02)
Unrealized Losses Related to NDT Fund Investments(b)	(24)	(0.03)	(38)	(0.04)
Plant Retirement and Divestitures(c)			193	0.22
Constellation Merger and Integration Costs(d)	26	0.03	36	0.04
Amortization of Commodity Contract Intangibles(e)	41	0.05	187	0.21
Amortization of the Fair Value of Certain Debt(f)			(3)	
Long-Lived Asset Impairment(h)	28	0.03		
Asset Retirement Obligation(i)	6	0.01	6	0.01
Adjusted (non-GAAP) Operating Earnings	$ 667	$ 0.78	$ 658	$ 0.77

	Nine Months Ended September 30,			
	2013		2012	
(All amounts after tax)		**Earnings per Diluted Share**		**Earnings per Diluted Share**
Net Income Attributable to Common Shareholders	$ 1,224	$ 1.42	$ 782	$ 0.97
Mark-to-Market Impact of Economic Hedging Activities(a)	(168)	(0.21)	(185)	(0.23)
Unrealized Gains Related to NDT Fund Investments(b)	(37)	(0.04)	(54)	(0.07)
Plant Retirement and Divestitures(c)	(13)	(0.01)	200	0.25
Constellation Merger and Integration Costs(d)	66	0.08	211	0.26
Amortization of Commodity Contract Intangibles(e)	273	0.32	545	0.68
Amortization of the Fair Value of Certain Debt(f)	(7)	(0.01)	(7)	(0.01)
Non-Cash Remeasurement of State Deferred Income Taxes(g)			(117)	(0.15)
Long-Lived Asset Impairment(h)	111	0.13		
Asset Retirement Obligation(i)	6	0.01	6	0.01
Remeasurement of Like-Kind Exchange Tax Position(j)	267	0.31		
Other Acquisition Costs(k)			3	
Maryland Commitments(l)			227	0.28
FERC Settlement(m)			172	0.22
Adjusted (non-GAAP) Operating Earnings	$ 1,722	$ 2.00	$ 1,783	$ 2.21

(a) Reflects the impact of gains for the three and nine months ended September 30, 2013 (net of taxes of $(99) million and $(112) million, respectively) and for the three and nine months ended September 30, 2012 (net of taxes of $(12) million and $(121) million, respectively), on Generation s economic hedging activities. See Note 10 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) losses for the three and nine months ended September 30, 2013 (net of taxes of $(39) million and $(66) million, respectively) and for the three and nine months ended September 30, 2012 (net of taxes of $(76) million and $(122) million, respectively) on Generation s NDT fund investments for Non-Regulatory Agreement Units. See Note 13 Nuclear Decommissioning of the Combined Notes to Consolidated Financial Statements for additional detail related to Generation s NDT fund investments.

(c) Reflects the impacts associated with the sale or retirement of generating stations for the nine months ended September 30, 2013 (net of taxes of $5 million) and for the three and nine months ended September 30, 2012 (net of taxes of $120 million and $123 million, respectively). See Results of Operations Generation for additional detail related to the generating station retirements.

(d) Reflects certain costs incurred for the three and nine months ended September 30, 2013 (net of taxes of $16 million and $19 million, respectively) and for the three and nine months ended September 30, 2012 (net of taxes of $52 million and $133 million, respectively) associated with the Constellation merger, employee-related expenses (e.g. severance, retirement, relocation and retention bonuses) integration initiatives and certain pre-acquisition contingencies, partially offset in 2013 by a one-time benefit pursuant to the BGE 2012 electric and gas distribution rate case order for the recovery of previously incurred integration costs. See Note 4 Merger and Acquisitions of the Combined Notes to Consolidated Financial Statements for additional information.

(e) Reflects the non-cash impact for the three and nine months ended September 30, 2013 and 2012 (net of taxes of $26 million and $174 million, respectively) and for the three and nine months ended September 30, 2012 (net of taxes of $121 million and $355 million, respectively) of the amortization of intangible assets, net, related to commodity contracts recorded at fair value at the Constellation merger date. See Note 4 Merger and Acquisitions of the Combined Notes to Consolidated Financial Statements for additional information.

(f) Reflects the non-cash amortization of certain debt for the nine months ended September 30, 2013 (net of taxes $(5) million) and for the three and nine months ended September 30, 2012 (net of taxes of $(2) million and $(4) million, respectively) recorded at fair value at the merger date which was retired in the second quarter of 2013. See Note 4 Merger and Acquisitions of the Combined Notes to Consolidated Financial Statements for additional information.

(g) Reflects the non-cash impacts of the remeasurement of state deferred income taxes as a result of the Constellation merger. See Note 12 Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information.

(h) Reflects 2013 impairment and related charges to earnings for the three and nine months ended September 30, 2013 (net of taxes of $18 million and $70 million, respectively) primarily related to Generation s cancellation of nuclear uprate projects and the impairment of certain wind generating assets.

(i) Reflects the impacts of an increase in Generation s asset retirement obligation for retired fossil plants for the three and nine months ended September 30, 2013 (net of taxes of $4 million). Reflects the impacts of an increase in Generation s decommissioning obligation for spent nuclear fuel at retired nuclear units for the three and nine months ended 2012 (net of taxes of $4 million).

(j) Reflects a non-cash charge to earnings for the nine months ended September 30, 2013 (net of taxes of $102 million) resulting from the first quarter 2013 remeasurement of a like-kind exchange tax position taken on ComEd s 1999 sale of fossil generating assets. See Note 12 Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information.

(k) Reflects certain costs incurred for the nine months ended September 30, 2012 (net of taxes of $2 million) associated with various acquisitions.

(l) Reflects costs incurred for the three months ended September 30, 2012 associated with the Constellation merger (net of taxes of $101 million) as part of the Maryland order approving the merger transaction. See Note 4 Merger and Acquisitions of the Combined Notes to Consolidated Financial Statements for additional information.

(m) Reflects costs incurred for the nine months ended September 30, 2012 (net of taxes of $23 million) as part of a settlement with the FERC to resolve a dispute related to Constellation's pre-merger hedging and risk management transactions. See Note 18 Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information.

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

For the three and nine months ended September 30, 2013, expense has been recognized for costs incurred to achieve the merger as follows:

	Pre-tax Expense Three Months Ended September 30, 2013				
Merger and Integration Costs:	**Generation(a)**	**ComEd**	**PECO**	**BGE(a)**	**Exelon(a)**
Employee-Related(b)	$ 20	$ 2	$ 2	$ 1	$ 27
Other(c)	12		1	1(d)	13
Total	$ 32	$ 2	$ 3	$ 2	$ 40

	Pre-tax Expense Nine Months Ended September 30, 2013				
Merger and Integration Costs:	**Generation(a)**	**ComEd**	**PECO**	**BGE(a)**	**Exelon(a)**
Employee-Related(b)	$ 32	$ 2	$ 3	$ 1	$ 41
Other(c)	42		5	(4)	45
Total	$ 74	$ 2	$ 8	$ (3)	$ 86

	Pre-tax Expense Three Months Ended September 30, 2012				
Merger and Integration Costs:	**Generation(a)**	**ComEd**	**PECO**	**BGE(a)**	**Exelon(a)**
Employee-Related(b)	$ 12	$	$ 2	$	$ 15
Other(c)	67		1	1(d)	72
Total	$ 79	$	$ 3	$ 1	$ 87

	Pre-tax Expense Nine Months Ended September 30, 2012				
Merger and Integration Costs:	**Generation(a)**	**ComEd**	**PECO**	**BGE(a)**	**Exelon(a)**
Transaction(e)	$	$	$	$	$ 52
Maryland Commitments	35			139	328
Employee-Related(b)	98		9		116
Other(c)	150	2	4	5	175
Total	$ 283	$ 2	$ 13	$ 144	$ 671

(a) For Exelon, Generation and BGE, includes the operations of the acquired businesses for the nine months ended September 30, 2013 and from the date of the merger, March 12, 2012, through September 30, 2012.

(b) Costs primarily for employee severance, pension and OPEB expense and retention bonuses. ComEd established regulatory assets of $0 million and $4 million during the three months ended September 30, 2013 and September 30, 2012 and $1 million and $20 million during the nine months ended September 30, 2013 and September 30, 2012, respectively. For ComEd, the majority of these costs are expected to be recovered over a five-year period. ComEd and BGE established a regulatory asset of $22 million and $22 million, respectively, during the nine months ended September 30, 2012, for severance benefit costs and the majority of these costs will be recovered over a five-year period. These costs are not included in the table above.

(c) Costs to integrate Constellation processes and systems into Exelon and to terminate certain Constellation debt agreements. ComEd established a regulatory asset of $2 million and $3 million during the three months ended September 30, 2013 and 2012 and $9 million and $10 million during the nine months ended September 30, 2013 and September 30, 2012, respectively, for certain other merger and integration costs, which are not included in the table above. BGE established a regulatory asset of $2 million during the nine months September 30, 2013 for certain other merger integration costs, which are not included in the table above.

(d) BGE established a regulatory asset of $6 million at September 30, 2013 for certain 2012 other merger integration costs as part of the 2013 electric and gas distribution rate case order.

(e) External, third-party costs paid to advisors, consultants, lawyers and other experts to assist in the due diligence and regulatory approval processes and in the closing of the transaction.

As of September 30, 2013, Exelon projects incurring total additional merger-related expenses, primarily in 2013, of $56 million.

Pursuant to the conditions set forth by the MDPSC in its approval of the merger transaction, Exelon committed to provide a package of benefits to BGE customers, and make certain investments in the City of Baltimore and the State of Maryland, resulting in an estimated direct investment in the State of Maryland of approximately $1 billion. The direct investment 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 is contingent upon the developer obtaining financing for the construction of the building. Once required approvals are received and financing conditions are met, construction of the building will commence and is expected to be ready for occupancy in 2 years. The direct investment estimate also includes $625 million in expenditures relating to the development of 285-300 MW of new electric generation facilities in Maryland (expected to be completed over the next ten years).

Exelon s Strategy and Outlook for the remainder of 2013 and Beyond

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

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

Generation s electricity generation strategy is to pursue opportunities that provide generation to load matching and that diversify the generation fleet by expanding Generation s regional and technological footprint. Generation leverages its energy generation portfolio to ensure delivery of energy to both wholesale and retail customers under long-term and short-term contracts, and in spot markets. Generation s customer facing activities foster development and delivery of other innovative energy-related products and services for its customers. Generation s presence in well-developed energy markets, its integrated hedging strategy mitigating short-term market volatility, and its low cost nuclear generating fleet operating consistently at high capacity factors, position it well to succeed in competitive energy markets.

Exelon s utility strategy is to improve reliability and operations and enhance the customer experience, while ensuring ratemaking mechanisms provide the utilities fair financial returns. Exelon seeks to leverage its scale and expertise across the utilities platform through enhanced standardization and sharing of best practices to achieve improved operational and financial results.

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

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

Power Markets

Price of Fuels. The use of new technologies to recover natural gas from shale deposits is increasing natural gas supply and reserves, which places downward pressure on natural gas prices and, therefore, on wholesale and retail power prices, which results in a reduction in Exelon s revenues. Since the third quarter of 2011, forward natural gas prices for 2013 and 2014 have declined significantly; in part reflecting an increase in supply due to strong natural gas production (due to shale gas development).

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

Various states have implemented or proposed legislation, regulations or other policies to subsidize new generation development which may result in artificially depressed wholesale energy and capacity prices. For example, 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 extended that date. The CfD mandates that utilities (including BGE) pay (or receive) the difference between CPV s contract price and the revenues it receives for capacity and energy from clearing the unit in the PJM capacity market.

Similar to Maryland, in January 2011, New Jersey passed legislation that provides guaranteed cost recovery through a fixed-price contract, referred to as a SOCA, for the development of up to 2,000 MWs of new base load or mid-merit generation, so long as it clears in PJM s capacity market. Three generation developers were chosen for the New Jersey SOCA, for which contracts were executed in 2011 by the state s utilities under protest. Similarly, in Illinois, legislation has been debated for over four years that passed in the Senate and is currently being considered in the House which would require consumers to subsidize the development of an Integrated Gasification Combined Cycle plant by purchasing its electricity through 30 year power purchase agreements at prices significantly above market prices. A new version was recently introduced in the current Illinois General Assembly but its prospects are unclear at this time.

Exelon and others filed a complaint in federal district court challenging the constitutionality and other aspects of the New Jersey legislation. Similarly, Exelon and others are also challenging the selection of the three generation developers in New Jersey state court proceedings and the MDPSC actions in Maryland state court. On October 25, 2013, the U.S. District Court in New Jersey judgment order finding that the New Jersey legislation violates the Supremacy Clause of the United States Constitution and the New Jersey SOCA contract is unenforceable. Similarly, on October 24, 2013, the U.S. District Court in Maryland issued a judgment order finding that the MDPSC s Order directing Baltimore Gas and Electric Company and two other Maryland electric distribution companies to enter into a CfD violates the Supremacy Clause of the United States Constitution, as described in Note 5 Regulatory Matters of the Combined Notes to Consolidated Financial Statements. In addition, on October 1, 2013, a Maryland State Circuit Court upheld the MDPSC Orders as being within the MDPSC s statutory authority under Maryland state law. This decision is separate from the judgment in the federal litigation that the MDPSC Order is unconstitutional and the CfD unenforceable under federal law. The federal judgment, if upheld, would prevent enforcement of the CfD even if the Circuit Court decision stands. It is anticipated that the non-prevailing parties in all three proceedings will file appeals. Finally, on October 23, 2013, the New Jersey state court dismissed the New Jersey state proceeding without prejudice, subject to the final outcome of the New Jersey federal litigation.

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

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

See Note 5 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on the Maryland Order.

Energy Demand. The continued tepid economic environment and growing energy efficiency initiatives have limited the demand for electricity across the Exelon utilities. ComEd is projecting load volumes for 2013 to slightly decrease from 2012, while PECO and BGE are projecting an increase (decrease) of 0.2% and (1.2%), respectively, in 2013 compared to 2012.

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

Strategic Policy Alignment

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

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

Decisions regarding the future of economically challenged generating assets will be based primarily on the economics of continued operation of the individual plants. 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 2013 and 2014. 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 September 30, 2013, the percentage of expected generation hedged for the major reportable segments was 97%-100%, 84%-87% and 48%-51% for 2013, 2014, and 2015, respectively. The percentage of expected generation hedged is the amount of equivalent sales divided by the expected generation. Expected generation represents the amount of energy estimated to be generated or purchased through owned or contracted capacity. Equivalent sales represent all hedging products, which include economic hedges and certain non-derivative contracts, including Generation s sales of energy to ComEd, PECO and BGE relating to their respective retail load obligations. Generation has been and will continue to be proactive in using hedging strategies to mitigate commodity price risk in subsequent years as well.

Generation procures coal, oil and natural gas through long-term and short-term contracts and spot-market purchases. Nuclear fuel is obtained predominantly through long-term uranium concentrate supply contracts, contracted conversion services, contracted enrichment services and contracted fuel fabrication services. The supply markets for uranium concentrates and certain nuclear fuel services, coal, oil and natural gas are subject to price fluctuations and availability restrictions. Supply market conditions may make Generation s procurement contracts subject to credit risk related to the potential non-performance of counterparties to deliver the contracted commodity or service at the contracted prices. Approximately 60% of Generation s uranium concentrate requirements from 2013 through 2017 are supplied by three producers. In the event of non-performance by these or other suppliers, Generation believes that replacement uranium concentrates can be obtained, although at prices that may be unfavorable when compared to the prices under the current supply agreements. Non-performance by these counterparties could have a material adverse impact on Exelon s and Generation s results of operations, cash flows and financial position. ComEd, PECO and BGE mitigate such exposure through regulatory mechanisms that allow them to recover procurement costs from retail customers.

Growth Opportunities

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

Smart Meter and Smart Grid Initiatives.

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

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

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

See Note 5 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on the Smart Meter and Smart Grid Initiatives.

Generation Renewable Development. On September 30, 2011, Exelon announced the completion of its acquisition of all of the interests in Antelope Valley, a 230-MW solar photovoltaic (PV) project under development in northern Los Angeles County, California, from First Solar, Inc., which is developing, building, operating, and maintaining the project. The first portion of the project began operations in December 2012, with six additional blocks coming online in 2013. Exelon has been informed by First Solar of issues relating to delays in the certification of certain components relating to the final two blocks of the project, which will delay commercial operation of these two blocks until the first half of 2014. The delay will not have a material financial effect on Exelon. Exelon expects the project to be in full commercial operation in the first half of 2014. The acquisition supports the Exelon commitment to renewable energy as part of Exelon 2020. The project has a 25-year PPA, approved by the CPUC, with Pacific Gas & Electric Company for the full output of the plant. Upon completion, the facility will add 230 MWs to Generation s renewable generation fleet. Total capitalized costs for the facility are expected to be approximately $1.1 billion. Total capitalized costs incurred through September 30, 2013 were approximately $964 million. In addition, Generation constructed and placed into service 400MWs of additional wind generation in 2012 at a cost of $710 million and another 46MW will be added to Generation s wind portfolio in 2014 with the expansion of its Beebe project in Michigan, the output of which will be fully contracted under a 20-year PPA.

Nuclear Uprate Program. Generation is engaged in individual projects as part of a planned power uprate program across its nuclear fleet. When economically viable, the projects take advantage of new production and measurement technologies, new materials and application of expertise gained from a half-century of nuclear power operations. Based on ongoing reviews, the nuclear uprate implementation plan has been adjusted in both the first and second quarters of 2013 to cancel certain projects. During the first quarter of 2013, 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. For these cancelled projects, Generation recorded approximately $21 million of operating and maintenance expense during the first quarter of 2013 to accrue remaining costs and reverse the previously capitalized costs. During the second quarter of 2013, market conditions prompted Generation to cancel the previously deferred extended power uprate projects at the LaSalle and Limerick nuclear stations. For these cancelled projects, Generation recorded a pre-tax charge during the second quarter of 2013 to operating and maintenance expense and interest expense of approximately $92 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 314 MWs of new nuclear generation at a cost of $891 million, which has been capitalized to property, plant and equipment on Exelon s and Generation s consolidated balance sheets. At September 30, 2013, Generation has capitalized $220 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 202 MWs of new nuclear generation, that are in the installation phase across four nuclear stations; Peach Bottom in Pennsylvania and Byron, Braidwood and Dresden in Illinois. The remaining spend associated with these projects is expected to be approximately $350 million through the end of 2016. Generation believes that it is probable that these projects will be completed. If a project is expected to not be completed as planned, previously capitalized costs will be reversed through earnings as a charge to operating and maintenance expense and interest.

Liquidity

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

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

Exposure to Worldwide Financial Markets. Exelon has exposure to worldwide financial markets. The ongoing European debt crisis has contributed to the instability in global credit markets. Further disruptions in the European markets could reduce or restrict the Registrants ability to secure sufficient liquidity or secure liquidity at reasonable terms. As of September 30, 2013, approximately 30%, or $2.5 billion, of the Registrants aggregate total commitments were with European banks. The credit facilities include $8.4 billion in aggregate total commitments of which $6.8 billion was available as of September 30, 2013. There were no borrowings under the Registrants credit facilities as of September 30, 2013. See Note 11 Debt and Credit Agreements of the Combined Notes to the Consolidated Financial Statements for additional information on the credit facilities.

Tax Matters

Exelon has exposure related to various uncertain tax positions which Exelon manages through planning and implementation of tax planning strategies. See Note 12 of the Combined Notes to Consolidated Financial Statements for additional information.

Environmental Legislative and Regulatory Developments.

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

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

In July 2011, the U.S. EPA published CSAPR and in June 2012, it issued final technical corrections. CSAPR requires 28 upwind states in the eastern half of the United States to significantly improve air quality by reducing power plant emissions that cross state lines and contribute to ground-level ozone and fine particle pollution in downwind states. On August 21, 2012, a three-judge panel of the D.C. Circuit Court held that the

U.S. EPA had exceeded its authority in certain material aspects with respect to CSAPR and vacated the rule and remanded it to the U.S. EPA for further rulemaking consistent with its decision. The Court also ordered that CAIR remain in effect pending finalization of CSAPR on remand. Until the U.S. EPA re-issues CSAPR, Exelon cannot determine the impacts of the rule, including any that would impact power prices. In June 2013, the U.S. Supreme Court granted the U.S. EPA s petition to review the D.C. Circuit Court s CSAPR decision. Oral argument has been scheduled for December 10, 2013.

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

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

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

In the absence of Federal legislation, the U.S. EPA is also moving forward with the regulation of GHG emissions under the Clean Air Act, including permitting requirements under the Prevention of Significant Deterioration (PSD) and Title V operating permit sections of the Clean Air Act for new and modified stationary sources that became effective January 2, 2011. Under the PSD regulations, new and modified major stationary sources could be required to install best available control technology, to be determined on a case-by-case basis. Pursuant to the President s Climate Action Plan, the U.S. EPA re-proposed regulations for the GHG emissions from new fossil fueled power plants on September 20, 2013. The U.S. EPA is also expected to propose by June 2014 GHG emission regulations for existing stationary sources under Section 111(d) of the Clean Air Act, and to issue final regulations by June 2015. While the nature and impact of the final regulations is not yet known, to the extent that the rule results in emission reductions from fossil fuel fired plants, imposing some form of direct or indirect price of carbon in competitive electricity markets, Exelon s overall low carbon generation portfolio results would benefit.

Water Quality. Section 316(b) of the Clean Water Act requires that cooling water intake structures at electric power plants reflect the best technology available to minimize adverse environmental impacts, and is implemented through state-level NPDES permit programs. On March 28, 2011, the U.S. EPA issued a proposed rule, and is required under a Settlement Agreement to issue a final rule by November 4, 2013; on October 30, 2013 the Agency invoked the *force majeure* provision of the Settlement Agreement to extend the final rule

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deadline until November 20, 2013 due to the early October 2013 federal government shutdown. The proposed rule does not require closed cycle cooling (e.g., cooling towers) as the best technology available, and also provides some flexibility in the use of cost-benefit considerations and site-specific factors. The proposed rule affords the state permitting agency wide discretion to determine the best technology available, which, depending on the site characteristics, could include closed cycle cooling, advanced screen technology at the intake, or retention of the current technology.

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

Hazardous and Solid Waste. Under proposed U.S. EPA rules issued on June 21, 2010, coal combustion residuals (CCR) would be regulated for the first time under the RCRA. The U.S. EPA is considering several options, including classification of CCR either as a hazardous or non-hazardous waste, under RCRA. Under either option, the U.S. EPA's intention is the ultimate elimination of surface impoundments as a waste treatment process. For plants affected by the proposed rules, this would result in significant capital expenditures and variable operating and maintenance expenditures to convert to dry handling and disposal systems and installation of new waste water treatment facilities. Generation s plants that would be affected by the proposed rules are Keystone and Conemaugh in Pennsylvania, which have on-site landfills that meet the requirements of Pennsylvania solid waste regulations for non-hazardous waste disposal. However, until the final rule is adopted, the impact on these facilities is unknown. The U.S. EPA has not announced a target date for finalization of the CCR rules; however, on October 29, 2013 EPA was issued a court order to submit a proposed schedule within 60 days for completing the CCR rulemaking.

See Note 18 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

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

Generation believes its nuclear generating facilities do not have the same operating risks as the Fukushima Daiichi plant because they meet the NRC s requirement that specifies all plants must be able to withstand the most severe natural phenomena historically reported for each plant s surrounding area, with a significant margin for uncertainty. In addition, Generation s plants are not located in significant earthquake zones or in regions where tsunamis are a threat. Generation believes its nuclear generating facilities are able to shut down safely and keep the fuel cooled through multiple redundant systems specifically designed to maintain electric power when electricity is lost from the grid. Further, Generation s nuclear generating facilities also undergo frequent scenario drills to ensure the proper function of the redundant safety protocols.

Since the events in Japan took place, Generation has continued to work with regulators and nuclear industry organizations to understand the events in Japan and apply lessons learned. Early on, the nuclear industry took a number of specific steps to respond, including actions requested by the Institute of Nuclear Power Operations (INPO) to perform tests that verified Generation s emergency equipment is available and functional, conduct walk-downs on its procedures related to critical safety equipment, confirm event response procedures and readiness to protect the spent fuel pool, and verify current qualifications of operators and support staff needed to implement the procedures. Generation has been addressing additional actions requested by INPO for improving and maintaining core and spent fuel pool cooling during an extended loss of power for at least 24 hours.

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 Task Force s report did not recommend any changes to the existing nuclear licensing process in the United States or changes in the storage of spent nuclear fuel within the plant s spent nuclear fuel pools. During the fourth quarter of 2011, the NRC staff issued its recommendations for prioritizing and implementing the Task Force recommendations and an implementation schedule which was approved by the NRC subject to a number of conditions. The NRC staff confirmed the Task Force s conclusions that none of the findings arising from the Task Force review presented an imminent risk to public health and safety.

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

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

Generation has assessed the impacts of the Tier 1 orders and information requests and will continue monitoring the additional recommendations under review by the NRC staff, both from an operational and a financial impact standpoint. A comprehensive review of the NRC Tier 1 orders and information requests, as well as preliminary engineering assumptions and analysis, indicate that the financial impact of compliance for the period from 2013 through 2018 is expected to be between approximately $375 million and $400 million of capital and $50 million of operating expense, respectively, as previously anticipated in Generation s planning projections. As Generation completes the design and installation planning for its actions, Generation will update these estimates. Further, Generation estimates incremental costs of $15 to $20 million per unit at eleven Mark I and II units for the installation of filtered vents, if ultimately required by the NRC. Generation s current assessments are specific to the Tier 1 recommendations as the NRC has not taken specific action with respect to the Tier 2 and Tier 3 recommendations. Exelon and Generation are unable to conclude at this time to what extent any actions to comply with the requirements of Tier 2 and Tier 3 will impact their future financial position, results of operations, and cash flows. Generation will continue to engage in nuclear industry assessments and actions and stakeholder input. See Item 1A. Risk Factors of the Exelon 2012 Form 10-K, for further discussion of the risk factors.

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

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

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

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

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

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

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

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

During March 2013, the Illinois House and Senate each passed Senate Bill 9 with supermajority votes to clarify the intent of EIMA on three major issues: average vs. year-end rate base and capital structure, return on pension asset, and a weighted average cost of capital interest rate on the prior year reconciliation. On May 22, 2013, the Illinois General Assembly overrode the Governor s May 5, 2013 veto of Senate Bill 9, which resulted in the legislation becoming effective immediately. The ICC issued a rate order on June 5, 2013 approving ComEd's May 30, 2013 filing to update 2013 rates reflecting Senate Bill 9 impacts. In addition, the ICC issued an interim order approving ComEd s accelerated meter deployment plan. ComEd projects the override of Senate Bill 9 will result in increased operating revenues of approximately $25 million for 2013 and $65 million in 2014, respectively. Also, ComEd projects that Senate Bill 9 will accelerate capital expenditures by approximately $40 million and $45 million in 2013 and 2014, respectively.

On September 4, 2013, the Attorney General filed a complaint (the Complaint) with the ICC to change the formula rate structure approved by the ICC on June 5, 2013. In the Complaint, the Attorney General proposed the following three changes to the formula: 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 October 2, 2013, the ICC opened an investigation (the Investigation) in which it undertook to review the three issues raised in the Complaint and determine if ComEd s current formula rate structure complies with Senate Bill 9. On October 31, 2013, the Attorney General asked to voluntarily withdraw the Complaint. ComEd is unable to predict the outcome of the Investigation; however, if the ICC were to rule against ComEd on these three issues, the impact could be material to ComEd s results of operations, cash flows, and financial position. ComEd expects the Investigation to be resolved in the fourth quarter of 2013.

See Note 5 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

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

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

FERC Transmission Complaint. On February 27, 2013, consumer advocates and regulators from the District of Columbia, New Jersey, Delaware and Maryland, and the Delaware Electric Municipal Cooperatives (the parties), filed a complaint at FERC against BGE and the Pepco Holdings, Inc. companies relating to their respective transmission formula rates. As of September 30, 2013, BGE cannot predict the likelihood or a reasonable estimate of the amount of a change, if any, in the allowed base return on equity, or a reasonable estimate of the refund period start date. While BGE cannot predict the outcome of this matter, if FERC orders a reduction of BGE s base return on equity to 8.7%, the annual impact would be a reduction in revenues of approximately $10 million.

See Note 5 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

The Maryland Strategic Infrastructure Development and Enhancement Program. In February 2013, the Maryland General Assembly passed legislation intended to accelerate gas infrastructure replacements in Maryland by establishing a mechanism for gas companies to promptly recover reasonable and prudent costs of eligible infrastructure replacement projects separate from base rate proceedings. Under the new law, following a proceeding before the MDPSC and with the MDPSC s approval of the eligible infrastructure replacement projects along with a corresponding surcharge, BGE could begin charging gas customers a monthly surcharge for infrastructure costs incurred after June 1, 2013. On August 2, 2013, BGE filed its infrastructure replacement plan and associated surcharge. The new surcharge rates are expected to take effect in the first quarter of 2014. BGE cannot predict the outcome of this proceeding or how much of the requested plan and related surcharge the MDPSC will approve.

See Note 5 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

2013 Maryland Electric and Gas Distribution Rate Case. On May 17, 2013, BGE filed an application for increases of $101 million and $30 million to its electric and gas base rates, respectively with the MDPSC. The requested rates of return on equity in the application are 10.50% and 10.35% for electric and gas distribution, respectively. On August 23, 2013, BGE filed an update to its rate request which altered the requested electric increase from $101 million to $83 million and the requested gas increase from $30 million to $24 million. The new electric and gas distribution base rates are expected to take effect in December 2013. BGE cannot predict the outcome of this proceeding or how much of the requested increases the MDPSC will approve.

See Note 5 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Critical Accounting Policies and Estimates

Management of each of the Registrants makes a number of significant estimates, assumptions and judgments in the preparation of its financial statements. See Management s Discussion and Analysis of Financial Condition and Results of Operations Critical Accounting Policies and Estimates in the Exelon s, Generation s, ComEd s, PECO s and BGE s combined 2012 Form 10-K for a discussion of the estimates and judgments necessary in the Registrants accounting for AROs, purchase accounting, asset impairments, depreciable lives of property, plant and equipment, defined benefit pension and other postretirement benefits, regulatory accounting, derivative instruments, taxation, contingencies and revenue recognition. At September 30, 2013, the Registrants critical accounting policies and estimates had not changed significantly from December 31, 2012.

Results of Operations

Net Income (Loss) Attributable to Common Shareholders by Registrant

	Three Months Ended September 30, 2013	Three Months Ended September 30, 2012	Favorable (Unfavorable) Variance	Nine Months Ended September 30, 2013	Nine Months Ended September 30, 2012(a)	Favorable (Unfavorable) Variance
Exelon	$ 738	$ 296	$ 442	$ 1,224	$ 782	$ 442
Generation	490	91	399	801	425	376
ComEd	126	90	36	140	219	(79)
PECO	92	122	(30)	285	297	(12)
BGE	50	(4)	54	150	(24)	174

(a) For BGE, reflects BGE s operations for the nine months ended September 30, 2012. For Exelon and Generation, includes the operations of the acquired businesses from, March 12, 2012, the date of the merger, through September 30, 2012.

Results of Operations Generation

	Three Months Ended September 30, 2013	Three Months Ended September 30, 2012	Favorable (Unfavorable) Variance	Nine Months Ended September 30, 2013	Nine Months Ended September 30, 2012(a)	Favorable (Unfavorable) Variance
Operating revenues	$ 4,255	$ 4,031	$ 224	$ 11,858	$ 10,539	$ 1,319
Purchased power and fuel expense	2,179	2,122	(57)	6,294	5,018	(1,276)
Revenue net of purchased power and fuel(b)	2,076	1,909	167	5,564	5,521	43
Other operating expenses						
Operating and maintenance	1,076	1,429	353	3,377	3,786	409
Depreciation and amortization	218	207	(11)	643	564	(79)
Taxes other than income	98	109	11	292	272	(20)
Total other operating expenses	1,392	1,745	353	4,312	4,622	310
Equity in earnings (losses) of unconsolidated affiliates	37	10	27	7	(69)	76
Operating income	721	174	547	1,259	830	429
Other income and (deductions)						
Interest expense	(82)	(85)	3	(257)	(223)	(34)
Other, net	134	83	51	229	185	44
Total other income and (deductions)	52	(2)	54	(28)	(38)	10
Income before income taxes	773	172	601	1,231	792	439
Income taxes	288	85	(203)	436	373	(63)
Net income	485	87	398	795	419	376
Net loss attributable to noncontrolling interests	(5)	(4)	1	(6)	(6)	
Net income attributable to membership interest	$ 490	$ 91	$ 399	$ 801	$ 425	$ 376

(a) Includes the operations of the acquired businesses from March 12, 2012, the date of the merger, through June 30, 2012.

(b) 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.

Net Income

Three Months Ended September 30, 2013 Compared to Three Months Ended September 30, 2012. Generation s net income attributable to membership interest increased compared to the same period in 2012 due to higher revenues, net of purchased power and fuel expense, decreases in transaction costs and employee-related costs associated with the merger, and higher earnings from Generation s interest in CENG; partially offset by the impairment of certain generating assets in 2013, and higher depreciation expense. The increase in revenues, net of purchased power and fuel expense was primarily due to increased capacity prices, mark-to-market gains and higher nuclear volume partially offset by lower realized energy prices and higher nuclear fuel cost in 2013.

Nine Months Ended September 30, 2013 Compared to Nine Months Ended September 30, 2012. Generation s net income attributable to membership interest increased compared to the same period in 2012 due to higher revenue, net of purchased power and fuel, 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, higher interest expense, and unfavorable NDT fund performance. The increase in revenues, 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 cost and lower mark-to-market gains in 2013. The decrease in operating and maintenance was largely due to 2012 costs associated with a settlement with FERC in March 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 entire United States footprint of MISO, 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 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.

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The following business activities are not allocated to a region, and are reported under Other: retail and wholesale gas, investments in natural gas exploration and production activities, proprietary trading, energy efficiency and demand response, heating, cooling, and cogeneration facilities, and home improvements, sales of electric and gas appliances, servicing of heating, air conditioning, plumbing, electrical, and indoor quality systems 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 as a result of the merger; and other miscellaneous revenues.

Generation evaluates the operating performance of its power marketing activities 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 three and nine months ended September 30, 2013 and 2012, Generation s revenue net of purchased power and fuel expense by region were as follows:

	Three Months Ended September 30,			
	2013	**2012**	**Variance**	**% Change**
Mid-Atlantic(b)	$ 864	$ 908	$ (44)	(4.8%)
Midwest(c)	601	729	(128)	(17.6%)
New England	62	81	(19)	(23.5%)
New York	(9)	13	(22)	n.m.
ERCOT	144	159	(15)	(9.4%)
Other Regions(d)	41	42	(1)	(2.4%)
Total electric revenue net of purchased power and fuel expense	$ 1,703	$ 1,932	$ (229)	(11.9%)
Proprietary Trading	1	(1)	2	n.m.
Mark-to-market gains	246	17	229	n.m.
Other(e)	126	(39)	165	n.m.
Total revenue net of purchased power and fuel expense	$ 2,076	$ 1,909	$ 167	8.8%

	Nine Months Ended September 30,			
	2013	**2012(a)**	**Variance**	**% Change**
Mid-Atlantic(b)	$ 2,475	$ 2,561	$ (86)	(3.4%)
Midwest(c)	2,001	2,310	(309)	(13.4%)
New England	142	180	(38)	(21.1%)
New York	(17)	60	(77)	(128.3%)
ERCOT	357	312	45	14.4%
Other Regions(d)	147	90	57	63.3%
Total electric revenue net of purchased power and fuel expense	$ 5,105	$ 5,513	$ (408)	(7.4%)
Proprietary Trading	13	10	3	30.0%
Mark-to-market gains	271	276	(5)	(1.8%)
Other(e)	175	(278)	453	n.m.
Total revenue net of purchased power and fuel expense	$ 5,564	$ 5,521	$ 43	0.8%

(a) Includes results for Constellation beginning on March 12, 2012, the date the merger was completed.
(b) Results of transactions with PECO and BGE are included in the Mid-Atlantic region.

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

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

(e) Other represents activities not allocated to a region. See text above for a description of included activities. Also includes amortization of intangible assets related to commodity contracts recorded at fair value at the merger date of $44 million and $386 million pre-tax for the three and nine months ended September 30, 2013, and $257 million and $793 million pre-tax for the three and nine months ended September 30, 2012.

Generation s supply sources by region are summarized below:

Supply source (GWh)	Three Months Ended September 30, 2013	2012	Variance	% Change
Nuclear generation(b)				
Mid-Atlantic	12,424	11,449	975	8.5%
Midwest	23,741	23,132	609	2.6%
Total Nuclear Generation	36,165	34,581	1,584	4.6%
Fossil and Renewables(b)				
Mid-Atlantic(b)(d)	2,808	2,547	261	10.2%
Midwest	217	171	46	26.9%
New England	3,609	3,953	(344)	(8.7%)
New York				
ERCOT	2,522	2,410	112	4.6%
Other Regions(e)	1,913	1,813	100	5.5%
Total Fossil and Renewables	11,069	10,894	175	1.6%
Purchased power				
Mid-Atlantic(c)	4,289	6,811	(2,522)	(37.0%)
Midwest	707	3,035	(2,328)	(76.7%)
New England	2,178	1,961	217	11.1%
New York(c)	3,565	4,026	(461)	(11.5%)
ERCOT	3,803	7,741	(3,938)	(50.9%)
Other Regions(e)	3,244	5,372	(2,128)	(39.6%)
Total Purchased Power	17,786	28,946	(11,160)	(38.6%)
Total supply/sales by region(f)				
Mid-Atlantic(g)	19,521	20,807	(1,286)	(6.2%)
Midwest(h)	24,665	26,338	(1,673)	(6.4%)
New England	5,787	5,914	(127)	(2.1%)
New York	3,565	4,026	(461)	(11.5%)
ERCOT	6,325	10,151	(3,826)	(37.7%)
Other Regions(e)	5,157	7,185	(2,028)	(28.2%)
Total supply/sales by region	65,020	74,421	(9,401)	(12.6%)

Supply source (GWh)	Nine Months Ended September 30, 2013	2012(a)	Variance	% Change
Nuclear generation(b)				
Mid-Atlantic	36,980	35,790	1,190	3.3%
Midwest	69,817	69,190	627	0.9%
Total Nuclear Generation	106,797	104,980	1,817	1.7%

Supply source (GWh)	Nine Months Ended September 30, 2013	2012(a)	Variance	% Change
Fossil and Renewables(b)				
Mid-Atlantic(b)(d)	8,764	6,654	2,110	31.7%
Midwest	1,116	671	445	66.3%
New England	9,133	7,597	1,536	20.2%
New York				
ERCOT	4,872	5,427	(555)	(10.2%)
Other Regions(e)	5,598	4,555	1,043	22.9%
Total Fossil and Renewables	29,483	24,904	4,579	18.4%
Purchased power				
Mid-Atlantic(c)	10,138	16,498	(6,360)	(38.6%)
Midwest	3,910	7,145	(3,235)	(45.3%)
New England	5,050	6,966	(1,916)	(27.5%)
New York(c)	10,149	7,779	2,370	30.5%
ERCOT	12,271	17,259	(4,988)	(28.9%)
Other Regions(e)	11,945	13,153	(1,208)	(9.2%)
Total Purchased Power	53,463	68,800	(15,337)	(22.3%)
Total supply/sales by region(f)				
Mid-Atlantic(g)	55,882	58,942	(3,060)	(5.2%)
Midwest(h)	74,843	77,006	(2,163)	(2.8%)
New England	14,183	14,563	(380)	(2.6%)
New York	10,149	7,779	2,370	30.5%
ERCOT	17,143	22,686	(5,543)	(24.4%)
Other Regions(e)	17,543	17,708	(165)	(0.9%)
Total supply/sales by region	189,743	198,684	(8,941)	(4.5%)

(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 does not include ownership through equity method investments (e.g., CENG).

(c) Purchased power for the three months and nine months ended September 30, 2013 includes physical volumes of 3,138 GWh and 8,840 GWh in the Mid-Atlantic and 3,147 GWh and 9,113 GWh in New York as a result of the PPA with CENG. Purchased power for the three months and nine months ended September 30, 2012 includes physical volumes of 3,126 GWh and 6,670 GWh in the Mid-Atlantic and 2,997 GWh and 6,536 GWh in New York as a result of the PPA with CENG.

(d) Excludes 2012 activity related to generation under the reliability-must-run rate schedule (YTD only) 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 2,499 GWh and 4,352 GWh for the three months ended September 30, 2013 and 2012, respectively, and 6,066 GWh and 9,981 GWh for the nine months ended September 30, 2013 and 2012, respectively.

(g) Includes sales to PECO through the competitive procurement process of 1,034 GWh and 2,350 GWh for the three months ended September 30, 2013 and 2012, respectively, and 4,196 GWh and 5,837 GWh for the nine months ended September 30, 2013 and 2012, respectively. Includes sales to BGE of 1,530 GWh and 1,075 GWh for the three months ended September 30, 2013 and 2012, respectively, and 4,386 GWh and 2,410 GWh for the nine months ended September 30, 2013 and 2012, respectively.

(h) Includes sales to ComEd under the RFP procurement of 3,720 GWh and 1,077 GWh for the three months ended September 30, 2013 and 2012, respectively, and 4,732 GWh and 4,152 GWh for the nine months ended September 30, 2013 and 2012, respectively.

The following table presents electric revenue net of purchased power and fuel expense per MWh of electricity sold during the three and nine months ended September 30, 2013 as compared to the three and nine months ended September 30, 2012.

	Three Months Ended September 30,		
$/MWh	**2013**	**2012**	**% Change**
Mid-Atlantic(b)	$ 44.26	$ 43.64	1.4%
Midwest(c)	24.37	27.68	(12.0%)
New England	10.71	13.70	(21.8%)
New York	(2.52)	3.23	(178.2%)
ERCOT	22.77	15.66	45.4%
Other Regions(d)	7.95	5.85	35.9%
Electric revenue net of purchased power and fuel expense per MWh(e)(f)	26.19	25.96	0.9%

	Nine Months Ended September 30,		
$/MWh(a)	**2013**	**2012(a)**	**% Change**
Mid-Atlantic(b)	$ 44.29	$ 43.48	1.9%
Midwest(c)	26.74	30.00	(10.9%)
New England	10.01	12.22	(18.1%)
New York	(1.68)	7.71	(121.7%)
ERCOT	20.82	13.75	51.5%
Other Regions(d)	8.38	5.08	64.9%
Electric revenue net of purchased power and fuel expense per MWh(e)(f)	26.90	27.75	(3.0%)

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

(b) Includes sales to PECO of $82 million (1,034 GWh) and $171 million (2,350 GWh) for the three months ended September 30, 2013 and 2012 respectively. Includes sales to PECO of $321 million (4,196 GWh) and $407 million (5,837 GWh) for the nine months ended September 30, 2013 and 2012 respectively. Includes sales to BGE of $144 million (1,530 GWh) and $120 million (1,075 GWh) for the three months ended September 30, 2013 and 2012, respectively. Includes sales to BGE of $356 million (4,386 GWh) and $223 million (2,410 GWh) for the nine months ended September 30, 2013 and 2012, respectively. Excludes compensation under the reliability-must-run rate schedule (YTD only) and the financial results of Brandon Shores, H.A. Wagner, and C.P. Crane, the generating facilities divested in the fourth quarter of 2012 as a result of the merger.

(c) Includes sales to ComEd of $143 million (3,720 GWh) and $47 million (1,077 GWh) and settlements of the ComEd swap of $0 million and $133 million for the three months ended September 30, 2013 and 2012, respectively. Includes sales to ComEd of $180 million (4,732 GWh) and $162 million (4,152 GWh) and settlements of the ComEd swap of $229 million and $469 million for the nine months ended September 30, 2013 and 2012, respectively

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

(e) Revenue net of purchased power and fuel expense per MWh represents the average margin per MWh of electricity sold during the three and nine months ended September 30, 2013 and 2012 and excludes the mark-to-market impact of Generation s economic hedging activities.

(f) Excludes Generation's other business activities not allocated to a region, including retail and wholesale gas, upstream natural gas, proprietary trading, energy efficiency, energy management and demand response. Also excludes Generation s compensation under the reliability-must-run rate schedule (YTD only), the financial results of Brandon Shores, H.A. Wagner, and C.P. Crane, the generating facilities divested in Q4 2012 as a result of the merger, and amortization of certain intangible assets relating to commodity contracts recorded at fair value as a result of the Exelon and Constellation merger of $44 million and $257 million, for the three months ended September 30, 2013 and 2012, respectively, and $386 million and $793 million, for the nine months ended September 30, 2013 and 2012, respectively.

Mid-Atlantic

Three Months Ended September 30, 2013 Compared to Three Months Ended September 30, 2012. The decrease in revenue net of purchased power and fuel expense in the Mid-Atlantic of $44 million was primarily due to lower realized energy prices and increased nuclear fuel expense, partially offset by higher capacity revenues, higher nuclear volumes, and lower energy supply costs as a result of increased integration of Generation s energy generation and load businesses.

Nine Months Ended September 30, 2013 Compared to Nine Months Ended September 30, 2012. The decrease in revenue net of purchased power and fuel expense in the Mid-Atlantic of $86 million was primarily due to lower realized energy prices and increased nuclear fuel expense, partially offset by higher capacity revenues, higher nuclear volumes, and lower energy supply costs as a result of increased integration of Generation s energy generation and load businesses, as well as the addition of Constellation in 2012.

Midwest

Three Months Ended September 30, 2013 Compared to Three Months Ended September 30, 2012. The decrease in revenue net of purchased power and fuel expense in the Midwest of $128 million was primarily due to lower realized energy prices and increased nuclear fuel expense, partially offset by higher capacity revenues, higher nuclear volumes and lower energy supply costs as a result of increased integration of Generation s energy generation and load businesses.

Nine Months Ended September 30, 2013 Compared to Nine Months Ended September 30, 2012. The decrease in revenue net of purchased power and fuel expense in the Midwest of $309 million was primarily due to lower realized energy prices, lower capacity revenues, and increased nuclear fuel expense, partially offset by higher nuclear volumes and lower energy supply costs as a result of increased integration of Generation s energy generation and load businesses, as well as the addition of Constellation in 2012.

New England

Three Months Ended September 30, 2013 Compared to Three Months Ended September 30, 2012. The $19 million decrease in revenue net of purchased power and fuel expense in New England was primarily due to lower realized energy prices, in addition to lower fossil generation due to increased fuel cost.

Nine Months Ended September 30, 2013 Compared to Nine Months Ended September 30, 2012. The $38 million decrease in revenue net of purchased power and fuel expense in New England was primarily due to lower realized energy prices, in addition to lower fossil generation due to increased fuel cost, 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

Three Months Ended September 30, 2013 Compared to Three Months Ended September 30, 2012. The $22 million decrease in revenue net of purchased power and fuel expense in New York was primarily due to decreased realized energy prices, in addition to lower retail and wholesale load margins.

Nine Months Ended September 30, 2013 Compared to Nine Months Ended September 30, 2012. The $77 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 in 2012. Prior to the merger, New York was not a significant contributor to revenue net of purchased power and fuel expense at Generation.

ERCOT

Three Months Ended September 30, 2013 Compared to Three Months Ended September 30, 2012. The $15 million decrease in revenue net of purchased power and fuel expense in ERCOT was primarily 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. In addition to the de-consolidation of the variable interest entity there was a decrease in load served offset by increased realized energy prices.

Nine Months Ended September 30, 2013 Compared to Nine Months Ended September 30, 2012. The $45 million increase in revenue net of purchased power and fuel expense in ERCOT was primarily due to the addition of Constellation in 2012, in addition to increased realized energy prices, partially offset by the de-consolidation of the variable interest entity and decreased load served.

Other Regions

Three Months Ended September 30, 2013 Compared to Three Months Ended September 30, 2012. The $1 million decrease in revenue net of purchased power and fuel expense in Other Regions was primarily due to decreased load served, partially offset by the increased integration of Generation s energy generation and load businesses.

Nine Months Ended September 30, 2013 Compared to Nine Months Ended September 30, 2012. The $57 million increase in revenue net of purchased power and fuel expense in Other Regions was primarily due to the addition of Constellation in 2012, in addition to increased integration of Generation s energy generation and load businesses, partially offset by decreased load served.

Mark-to-market

Three Months Ended September 30, 2013 Compared to Three Months Ended September 30, 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 $246 million for the three months ended September 30, 2013 compared to gains of $17 million for the three months ended September 30, 2012. See Notes 9 Fair Value of Financial Assets and Liabilities and 10 Derivative Financial Instruments of the Combined Notes to the Consolidated Financial Statements for information on gains and losses associated with mark-to-market derivatives.

Nine Months Ended September 30, 2013 Compared to Nine Months Ended September 30, 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 $271 million for the nine months ended September 30, 2013 compared to gains of $276 million for the nine months ended September 30, 2012. See Notes 9 Fair Value of Financial Assets and Liabilities and 10 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

Three Months Ended September 30, 2013 Compared to Three Months Ended September 30, 2012. The $165 million increase in other revenue net of purchased power and fuel was primarily due to the decrease in amortization of the acquired energy contracts recorded at fair value at the merger date. In addition, other revenue net of purchased power and fuel for 2012 includes the results of Brandon Shores, H.A. Wagner and C.P. Crane, the generating facilities divested in the fourth quarter 2012 as a result of the Exelon and Constellation merger. See Note 4 Merger and Acquisitions 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.

Nine Months Ended September 30, 2013 Compared to Nine Months Ended September 30, 2012. The $453 million increase in other revenue net of purchased power and fuel was primarily due to the decrease of the amortization of the acquired energy contracts recorded at fair value at the merger date, in addition to the addition of Constellation in 2012, which includes wholesale and retail gas, energy efficiency, energy management and demand response, upstream natural gas and the design and construction of renewable energy facilities. In addition, other revenue net of purchased power and fuel for 2012 includes the results of Brandon Shores, H.A. Wagner and C.P. Crane, the generating facilities divested in the fourth quarter 2012 as a result of the Exelon and Constellation merger. These positive factors were partially offset by a decrease in the compensation under the reliability-must-run rate tariff schedules for such facilities. See Note 4 Merger and Acquisitions 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 the three and nine months ended September 30, 2013 as compared to the same periods in September 30, 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 and certain other non-production related overhead costs. Generation considers capacity factor and production costs useful measures comparatively 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.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	**2012**	**2013**	**2012**
Nuclear fleet capacity factor(a)	94.8 %	90.7 %	94.7 %	92.6 %
Nuclear fleet production cost per MWh(a)	$ 18.87	$ 19.04	$ 19.14	$ 19.19

(a) Reflects ownership percentage of stations operated by Exelon. Excludes Salem, which is operated by PSEG Nuclear, LLC, and Exelon s ownership in jointly owned generating plants through equity method investments (e.g. CENG).

Three Months Ended September 30, 2013 Compared to Three Months Ended September 30, 2012. The nuclear fleet capacity factor increased primarily due to fewer non-refueling outage days, excluding Salem outages, during the three months ended September 30, 2013 compared to the same period in 2012. For the three months ended September 30, 2013 and 2012, non-refueling outage days totaled 5 and 40, respectively. During the same periods, refueling outage days totaled 43 and 43, respectively. Higher number of net MWhs generated resulted in a lower production cost per MWh for the three months ended September 30, 2013 as compared to the same period in 2012.

Nine Months Ended September 30, 2013 Compared to Nine Months Ended September 30, 2012. The nuclear fleet capacity factor increased primarily due to fewer refueling outage days and non-refueling outage days, excluding Salem outages, during the nine months ended September 30, 2013 compared to the same period in 2012. For the nine months ended September 30, 2013 and 2012, non-refueling outage days totaled 42 and 72, respectively. During the same periods, refueling outage days totaled 139 and 161, respectively. Higher number of net MWhs generated resulted in a lower production cost per MWh for the nine months ended September 30, 2013 as compared to the same period in 2012.

Operating and Maintenance Expense

The changes in operating and maintenance expense for the three and nine months ended September 30, 2013 compared to the same period in 2012, consisted of the following:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	Increase (Decrease)		Increase (Decrease)	
FERC settlement(a)	$		$	(195)
Labor, other benefits, contracting and materials		(34)		117
Impairment and related charges of certain generating assets		46		159
Constellation merger and integration costs		5		(66)
Maryland commitments				(35)
Corporate allocations(b)		(22)		(9)
Pension and non-pension postretirement benefits expense		8		15
Nuclear refueling outage costs, including the co-owned Salem plant(c)		6		9
Bodily injury costs(d)				(12)
Plant retirements and divestitures(e)		(337)		(393)
Bad debt expense		(11)		12
Other		(14)		(11)
Decrease in operating and maintenance expense	$	(353)	$	(409)

(a) 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.
(b) The decrease in cost allocations during the three months ended September 30, 2013 primarily reflects merger synergy savings for Exelon s corporate operations and shared service entities, partially offset during nine months ended September 30, 2013 by the impact of an increased share of corporate allocated costs due to the merger.
(c) Reflects the impact of decreased planned refueling outage days, partially offset by increased nuclear fueling outage costs related to Generation s ownership interest in Salem for nine months ended September 30, 2013 compared to same period in 2012.
(d) Reflects decreased asbestos-related bodily injury expense for nine months ended September 30, 2013 compared to same period in 2012.
(e) Reflects the operating and maintenance expense associated with the generating assets retired or divested during 2012.

Depreciation and Amortization

Three Months Ended September 30, 2013 Compared to Three Months Ended September 30, 2012.

The increase in depreciation and amortization was primarily due to higher plant balances resulting from capital additions, increased nuclear fuel amortization costs, and wind and solar facilities placed into service in the second half of 2012 and in the first half of 2013.

Nine Months Ended September 30, 2013 Compared to Nine Months Ended September 30, 2012.

The increase in depreciation and amortization was primarily due to higher plant balances resulting from the addition of Constellation s plant balances for full year to date 2013. The increase in depreciation and amortization expense was also due capital additions, increased nuclear fuel amortization costs, and wind and solar facilities placed into service in the second half of 2012 and in the first half of 2013.

Taxes Other Than Income

The decrease in taxes other than income for the three and nine months ended September 30, 2013 as compared to the three and nine months ended September 30, 2012 was primarily due to lower gross receipts tax. The increase in taxes other than income for the nine months ended September 30, 2013 compared to nine months ended September 30, 2012 was primarily due to addition of Constellation s financial results in 2012.

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Equity in Earnings (Loss) of Unconsolidated Affiliates

The favorable increase in Equity in earnings/loss of unconsolidated affiliates for the three and nine months ended September 30, 2013 was primarily due to higher net income from Generation's equity investment in CENG in 2013 compared to same period in 2012 and lower amortization of the basis difference of Generation s ownership interest in CENG recorded at fair value in connection with the Merger.

Interest Expense

Three Months Ended September 30, 2013 Compared to Three Months Ended September 30, 2012.

Interest expense for three months ended September 30, 2013 compared to same period in 2012 remained relatively level.

Nine Months Ended September 30, 2013 Compared to Nine Months Ended September 30, 2012.

The increase in interest expense was primarily due to the increase in long-term debt as a result of the merger and the reversal of previously capitalized interest expense related to power uprate projects that were cancelled during second quarter of 2013.

Other, Net

Three Months Ended September 30, 2013 Compared to Three Months Ended September 30, 2012. Other, net primarily reflects the change in the net unrealized gains (losses) related to the NDT funds of the Non-Regulatory Agreement Units as described in the table below. Other, net also reflects $43 million of credit facility termination fees recorded in 2012.

Nine Months Ended September 30, 2013 Compared to Nine Months Ended September 30, 2012. Other, net primarily reflects the change in the net unrealized gains (losses) related to the NDT funds of the Non-Regulatory Agreement Units as described in the table below. Other, net also reflects $73 million and $100 million of income in 2013 and 2012, respectively, related to the contractual elimination of income tax expense associated with the NDT funds of the Regulatory Agreement Units and $85 million of credit facility termination fees recorded in 2012

The following table provides unrealized and realized gains and losses on the NDT funds of the Non-Regulatory Agreement Units recognized in Other, net for the three and nine months ended September 30, 2013 and 2012:

	Three Months Ended September 30,		**Nine Months Ended September 30,**	
	2013	**2012**	**2013**	**2012**
Net unrealized gains on decommissioning trust funds	$ 46	$ 71	$ 70	$ 101
Net realized gains on sale of decommissioning trust funds	$ 22	$ 1	$ 25	$ 41

Effective Income Tax Rate

The effective income tax rate was 37.3% and 35.4% for the three and three months ended September 30, 2013, respectively, compared to 49.4% and 47.1% for the same periods during 2012. See Note 12 of the Combined Notes to the Consolidated Financial Statements for further discussion of the change in the effective income tax rate.

Results of Operations ComEd

	Three Months Ended September 30, 2013	Three Months Ended September 30, 2012	Favorable (Unfavorable) Variance	Nine Months Ended September 30, 2013	Nine Months Ended September 30, 2012	Favorable (Unfavorable) Variance
Operating revenues	$ 1,156	$ 1,484	$ (328)	$ 3,395	$ 4,154	$ (759)
Purchased power expense	301	678	377	931	1,886	955
Revenue net of purchased power expense(a)	855	806	49	2,464	2,268	196
Other operating expenses						
Operating and maintenance	333	350	17	1,020	1,000	(20)
Depreciation and amortization	164	157	(7)	501	458	(43)
Taxes other than income	80	81	1	225	224	(1)
Total other operating expenses	577	588	11	1,746	1,682	(64)
Operating income	278	218	60	718	586	132
Other income and (deductions)						
Interest expense, net	(74)	(74)		(503)	(230)	(273)
Other, net	7	5	2	18	12	6
Total other income and (deductions)	(67)	(69)	2	(485)	(218)	(267)
Income before income taxes	211	149	62	233	368	(135)
Income taxes	85	59	(26)	93	149	56
Net income	$ 126	$ 90	$ 36	$ 140	$ 219	$ (79)

(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

Three Months Ended September 30, 2013, Compared to Three Months Ended September 30, 2012. ComEd s net income for the three months ended September 30, 2013, was higher than the same period in 2012, primarily due to increased distribution revenue as a result of increased capital investment and higher allowed ROE pursuant to the formula rate under EIMA and the enactment of Senate Bill 9. These increases were partially offset by unfavorable weather conditions during the third quarter of 2013.

Nine Months Ended September 30, 2013, Compared to Nine Months Ended September 30, 2012. ComEd s net income for the nine months ended September 30, 2013, was lower than the same period in 2012, primarily due to the remeasurement of Exelon s like-kind exchange tax position in the first quarter of 2013 and unfavorable weather conditions through the third quarter of 2013. These decreases were partially offset by the discrete impacts of the ICC s May 2012 Order in ComEd s 2011 formula rate proceeding under EIMA, increased distribution revenue as a result of increased capital investment and higher allowed ROE pursuant to the formula rate under EIMA and the enactment of Senate Bill 9. See Note 5 Regulatory Matters and Note 12 Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information.

Operating Revenues Net of Purchased Power Expense

There are certain drivers of revenue that are fully offset by their impact on purchased power expense, such as commodity procurement costs and customer choice programs. ComEd is permitted to recover electricity

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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 5 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on ComEd s electricity procurement process.

Electric revenues and purchased power expense are affected by fluctuations in customers purchases from competitive electric generation suppliers. All ComEd customers have the choice to purchase electricity from a competitive electric generation supplier. The customers choice of retail electric supplier does not impact ComEd s volume of deliveries, but does affect ComEd s energy revenue. The number of retail customers purchasing electricity from competitive electric generation suppliers was 2,621,356 and 1,453,061 at September 30, 2013, and 2012, respectively, representing 68% and 38% of total retail customers, respectively. Retail energy purchased from competitive electric generation suppliers represented 81% and 79% of ComEd s retail kWh sales for the three months and nine months ended September 30, 2013, respectively, as compared to 64% and 62% for the three and nine months ended September 30, 2012, respectively. During 2012, the City of Chicago and approximately 240 Illinois municipalities, including governmental entities such as townships and counties, approved referenda regarding electric supply aggregation. The referenda allowed governmental officials to identify and sign contracts with competitive electric generation suppliers on behalf of the eligible retail customers in the community, while also allowing customers to opt-out of the municipal aggregation program. As of September 30, 2013, there are approximately 330 municipalities that have approved a municipal aggregation referendum in the ComEd service territory. As a result, approximately 70% of residential usage as of September 30, 2013 is being supplied by competitive electric generation suppliers, and ComEd estimates that over 80% of that usage resulted from municipal aggregation activities. ComEd anticipates that as municipalities continue to implement aggregation programs throughout 2013, and as non-municipal aggregation switching continues to increase, slightly less than three-quarters of total residential usage will be supplied by competitive electric generation suppliers by the end of 2013.

The changes in ComEd s revenue net of purchased power expense for the three months and nine months ended September 30, 2013, compared to the same periods in 2012 consisted of the following:

	Three Months Ended September 30, Increase (Decrease)	Nine Months Ended September 30, Increase (Decrease)
Weather	$ (27)	$ (31)
Volume	(4)	(3)
Electric distribution revenues	66	143
Discrete impacts of the 2012 Distribution Rate Case Order		88
Senate Bill 9	10	20
Transmission revenues	11	14
Regulatory required programs	6	7
Uncollectible accounts recovery, net	(28)	(43)
Other	15	1
Total increase	$ 49	$ 196

Weather. The demand for electricity is affected by weather conditions. Very warm weather in summer months and very cold weather in other months are considered favorable weather conditions because these weather conditions result in increased customer usage. Conversely, mild weather reduces demand. For the three and nine months ended September 30, 2013, the increase in revenue net of purchased power expense was offset by unfavorable weather conditions as a result of the mild weather through the third quarter of 2013, compared to the same period in 2012.

Heating and cooling degree days are quantitative indices that reflect the demand for energy needed to heat or cool a home or business. Normal weather is determined based on historical average heating and cooling degree days for a 30-year period in ComEd's service territory, with cooling degree days generally having a more significant impact to ComEd, particularly during the summer months. The changes in heating and cooling degree days in ComEd s service territory for the three months and nine months ended September 30, 2013 and 2012, consisted of the following:

				% Change	
Heating and Cooling Degree-Days	**2013**	**2012**	**Normal**	**From 2012**	**From Normal**
Three Months Ended September 30,					
Heating Degree-Days	79	107	119	(26.2)%	(33.6)%
Cooling Degree-Days	668	859	613	(22.2)%	9.0 %
Nine Months Ended September 30,					
Heating Degree-Days	4,116	3,035	4,048	35.6 %	1.7 %
Cooling Degree-Days	908	1,321	831	(31.3)%	9.3 %

Volume. Revenue net of purchased power expense decreased as a result of lower delivery volume, exclusive of the effects of weather, for the three and nine months ended September 30, 2013, reflecting decreased average usage per residential customer as compared to the same period in 2012.

Electric Distribution Revenues. EIMA provides for a performance-based formula rate tariff, which requires an annual reconciliation of the revenue requirement in effect to the actual costs that the ICC determines are prudently and reasonably incurred in a given year. During the three and nine months ended September 30, 2013, ComEd recorded increased revenue net of purchased power expense of $66 million and $143 million, respectively, associated with the 2011 through 2013 reconciliations. These amounts exclude the discrete impacts of the May 2012 Distribution Rate Case Order and the enactment of Senate Bill 9 in May 2013, discussed separately below. See Note 5 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Discrete Impacts of the 2012 Distribution Rate Case Order. On May 30, 2012, the ICC issued its final Order related to ComEd s 2011 formula rate proceeding under EIMA, which resulted in a reduction to revenue net of purchased power expense of $0 million and $88 million for the three and nine months ended September 30, 2012. See Note 3 Regulatory Matters of the Exelon 2012 Form 10-K for further information.

Senate Bill 9. On May 22, 2013, the Illinois General Assembly overrode the Governor s May 5, 2013 veto of Senate Bill 9, which became effective immediately. Revenue net of purchased power expense increased by $10 million and $20 million for the three and nine months ended September 30, 2013, as a result of the enactment of Senate Bill 9. See Note 5 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Transmission Revenues. ComEd s transmission rates are established based on a FERC-approved formula. ComEd s most recent annual formula rate update, filed in April 2013, reflects 2012 actual costs plus forecasted 2013 capital additions. Transmission revenue net of purchased power expense vary from year to year based upon fluctuations in the underlying costs, investments being recovered and other billing determinants, such as the highest daily peak load from the previous calendar year. See Note 5 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Regulatory Required Programs. Revenues related to regulatory required programs are the recoveries from customers for costs of various legislative and/or regulatory programs on a full and current basis through approved regulated rates. Programs include ComEd s energy efficiency and demand response and purchased power administrative costs. An equal and offsetting amount has been reflected in operating and maintenance expense during the periods presented. See the operating and maintenance expense discussion below for additional information on included programs.

Uncollectible Accounts Recovery, Net. Represents recoveries under ComEd s uncollectible accounts tariff. See the operating and maintenance expense discussion below for additional information on this tariff.

Other. Other revenues increased during the three and nine months ended September 30, 2013, compared to the same periods in 2012. Other revenues, which can vary period to period, include rental revenues, revenues related to late payment charges, assistance provided to other utilities through mutual assistance programs and recoveries of environmental costs associated with MGP sites.

Operating and Maintenance Expense

	Three Months Ended September 30, 2013	Three Months Ended September 30, 2012	Increase (Decrease)	Nine Months Ended September 30, 2013	Nine Months Ended September 30, 2012	Increase (Decrease)
Operating and maintenance expense baseline	$ 299	$ 322	$ (23)	$ 892	$ 879	$ 13
Operating and maintenance expense regulatory required programs(a)	34	28	6	128	121	7
Total operating and maintenance expense	$ 333	$ 350	$ (17)	$ 1,020	$ 1,000	$ 20

(a) Operating and maintenance expenses for regulatory required programs are costs for various legislative and/or regulatory programs that are recoverable from customers on a full and current basis through approved regulated rates. An equal and offsetting amount has been reflected in operating revenues.

The changes in operating and maintenance expense for the three and nine months ended September 30, 2013 compared to the same periods in 2012, consisted of the following:

	Three Months Ended September 30, Increase (Decrease)	Nine Months Ended September 30, Increase (Decrease)
Baseline		
Labor, other benefits, contracting and materials(a)	$ 16	$ 42
Pension and non-pension postretirement benefits expense	(7)	3
Storm-related costs(b)	(9)	
Uncollectible accounts expense provision(c)	(4)	(13)
Uncollectible accounts expense recovery, net(c)	(24)	(30)
Other	5	11
	(23)	13
Regulatory required programs		
Energy efficiency and demand response programs	6	7
	6	7
Increase (Decrease) in operating and maintenance expense	$ (17)	$ 20

(a) The increase includes contracting costs resulting from new projects associated with EIMA. See Note 5 Regulatory Matters of the Combined Notes to Financial Statements for additional information regarding EIMA.

(b) Under EIMA, ComEd may recover costs associated with certain one-time events, such as large storms, over a five-year period. During the third quarter of 2012, ComEd recorded a net reduction in operating and maintenance expense for costs related to significant third quarter 2012 storms.

(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.

Depreciation and Amortization

Depreciation and amortization expense increased during the three and nine months ended September 30, 2013, compared to the same periods in 2012, primarily due to ongoing capital expenditures and increased regulatory asset amortization related to higher MGP remediation expenditures. An equal and offsetting amount for the amortization expense related to the MGP remediation expenditures is reflected in operating revenues during the periods presented.

Taxes Other Than Income

Taxes other than income taxes remained relatively flat for the three and nine months ended September 30, 2013, compared to the same periods in 2012. Taxes other than income taxes, which can vary period to period, include municipal and state utility taxes, real estate taxes and payroll taxes.

Interest Expense, Net

The changes in Interest Expense, net for the three and nine months ended September 30, 2013, compared to the same period in 2012, consisted of the following:

	Three Months Ended September 30,	Nine Months Ended September 30,
	Increase (Decrease)	**Increase (Decrease)**
Interest expense related to uncertain tax positions(a)	$ 1	$ 278
Interest expense on debt (including financing trusts)		(1)
Other	(1)	(4)
Increase in interest expense, net	$	$ 273

(a) Primarily reflects the remeasurement of Exelon s like-kind exchange tax position in the first quarter of 2013. See Note 12 Income Taxes of the Combined Notes to Financial Statements for additional information.

Effective Income Tax Rate

The effective income tax rate was 40.3% for the three months ended September 30, 2013 compared to 39.6% for the same period during 2012. The effective income tax rate was 39.9% for the nine months ended September 30, 2013 compared to 40.5% for the same period during 2012. See Note 12 Income Taxes of the Combined Notes to Consolidated Financial Statements for further discussion of the change in the effective income tax rate.

ComEd Electric Operating Statistics and Revenue Detail

Retail Deliveries to Customers (in GWhs)	Three Months Ended September 30, 2013	2012	% Change	Weather-Normal % Change
Retail Delivery and Sales(a)				
Residential	8,188	9,265	(11.6)%	(2.4)%
Small commercial & industrial	8,680	8,939	(2.9)%	(0.1)%
Large commercial & industrial	7,381	7,506	(1.7)%	(0.2)%
Public authorities & electric railroads	329	314	4.8%	9.1%
Total Retail Deliveries	24,578	26,024	(5.6)%	(0.8)%

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Retail Deliveries to Customers (in GWhs)	Nine Months Ended September 30, 2013	2012	% Change	Weather-Normal % Change
Retail Delivery and Sales(a)				
Residential	21,154	22,345	(5.3)%	(0.7)%
Small commercial & industrial	24,385	24,742	(1.4)%	(0.4)%
Large commercial & industrial	20,932	21,048	(0.6)%	(0.4)%
Public authorities & electric railroads	997	932	7.0%	10.5%
Total Retail Deliveries	67,468	69,067	(2.3)%	(0.4)%

Number of Electric Customers	As of September 30, 2013	2012
Residential	3,465,635	3,450,364
Small commercial & industrial	366,216	365,245
Large commercial & industrial	1,978	1,986
Public authorities & electric railroads	4,860	4,795
Total	3,838,689	3,822,390

Electric Revenue	Three Months Ended September 30, 2013	2012	% Change	Nine Months Ended September 30, 2013	2012	% Change
Retail Delivery and Sales(a)						
Residential	$ 529	$ 876	(39.6)%	$ 1,589	$ 2,372	(33.0)%
Small commercial & industrial	322	344	(6.4)%	945	997	(5.2)%
Large commercial & industrial	112	102	9.8%	327	296	10.5%
Public authorities & electric railroads	12	11	9.1%	35	32	9.4%
Total Retail	975	1,333	(26.9)%	2,896	3,697	(21.7)%
Other Revenue(b)	181	151	19.9%	499	457	9.2%
Total Electric Revenues	$ 1,156	$ 1,484	(22.1)%	$ 3,395	$ 4,154	(18.3)%

(a) Reflects delivery revenues and volumes from customers purchasing electricity directly from ComEd and customers purchasing electricity from a competitive electric generation supplier, as all customers are assessed delivery charges. For customers purchasing electricity from ComEd, revenue also reflects the cost of energy and transmission.

(b) Other revenue primarily includes transmission revenue from PJM. Other items include rental revenues, revenues related to late payment charges, assistance provided to other utilities through mutual assistance programs, and recoveries of environmental costs associated with MGP sites.

Results of Operations PECO

	Three Months Ended September 30, 2013	Three Months Ended September 30, 2012	Favorable (Unfavorable) Variance	Nine Months Ended September 30, 2013	Nine Months Ended September 30, 2012	Favorable (Unfavorable) Variance
Operating revenues	$ 728	$ 806	$ (78)	$ 2,295	$ 2,396	$ (101)
Purchased power and fuel	289	326	37	953	1,033	80
Revenue net of purchased power and fuel(a)	439	480	(41)	1,342	1,363	(21)
Other operating expenses						
Operating and maintenance	186	199	13	554	574	20
Depreciation and amortization	57	55	(2)	171	161	(10)
Taxes other than income	41	48	7	121	122	1
Total other operating expenses	284	302	18	846	857	11
Operating income	155	178	(23)	496	506	(10)
Other income and (deductions)						
Interest expense, net	(29)	(32)	3	(86)	(94)	8
Other, net	1	2	(1)	4	6	(2)
Total other income and (deductions)	(28)	(30)	2	(82)	(88)	6
Income before income taxes	127	148	(21)	414	418	(4)
Income taxes	35	25	(10)	122	118	(4)
Net income	92	123	(31)	292	300	(8)
Preferred security dividends and redemption		1	(1)	7	3	4
Net income attributable to common shareholders	$ 92	$ 122	$ (30)	$ 285	$ 297	$ (12)

(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 shareholders

Three Months Ended September 30, 2013 Compared to Three Months Ended September 30, 2012. The decrease in net income attributable to common shareholders was driven primarily by lower operating revenue net of purchased power and fuel expense and an increase to income tax expense, partially offset by lower operating and maintenance expense.

Nine Months Ended September 30, 2013 Compared to Nine Months Ended September 30, 2012. The decrease in net income attributable to common shareholders was driven primarily by lower operating revenue net of purchased power and fuel expense and an increase in depreciation and amortization expense, partially offset by lower operating and maintenance expenses.

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Operating Revenues, Purchased Power and Fuel Expense

Electric and gas revenues and purchased power and fuel expense are affected by fluctuations in commodity procurement costs. PECO's electric supply and natural gas cost rates charged to customers are subject to adjustments at least quarterly that are designed to recover or refund the difference between the actual cost of electric supply and natural gas and the amount included in rates in accordance with the PAPUC's GSA and PGC, respectively. Therefore, fluctuations in electric supply and natural gas procurement costs have no impact on electric and gas revenue net of purchased power and fuel expense.

Electric and gas revenues and purchased power and fuel expense are also affected by fluctuations in participation in the Customer Choice Program. All PECO customers have the choice to purchase electricity and gas from competitive electric generation and natural gas suppliers, respectively. The customer's choice of suppliers does not impact the volume of deliveries, but affects 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 purchased power and fuel expense. The number of retail customers purchasing electricity from a competitive electric generation supplier was 518,061 and 464,800 at September 30, 2013 and 2012, respectively. Retail deliveries purchased from competitive electric generation suppliers represented 69% and 68% of PECO's retail kWh sales for the three and nine months ended September 30, 2013, respectively, compared to 65% for the three and nine months ended September 30, 2012. The number of retail customers purchasing natural gas from a competitive natural gas supplier was 60,390 and 48,600 at September 30, 2013 and 2012, respectively. Retail deliveries purchased from competitive natural gas suppliers represented 23% and 19% of PECO's mmcf sales for the three and nine months ended September 30, 2013, respectively, compared to 69% and 47% for the three and nine months ended September 30, 2012.

The changes in PECO s operating revenues net of purchased power and fuel expense for the three months ended September 30, 2013 compared to the same period in 2012 consisted of the following:

	Increase (Decrease)		
	Electric	Gas	Total
Weather	$ (20)	$	$ (20)
Volume			
Pricing			
Regulatory required programs	(15)		(15)
Gross Receipts Tax	(1)		(1)
Other	(4)	(1)	(5)
Total decrease	$ (40)	$ (1)	$ (41)

The changes in PECO s operating revenues net of purchased power and fuel expense for the nine months ended September 30, 2013 compared to the same period in 2012 consisted of the following:

	Increase (Decrease)		
	Electric	Gas	Total
Weather	$ (4)	$ 27	$ 23
Volume	(3)	(3)	(6)
Pricing	(9)		(9)
Regulatory required programs	(10)		(10)
Gross Receipts Tax	(7)		(7)
Other	(7)	(5)	(12)
Total (decrease) increase	$ (40)	$ 19	$ (21)

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. During the three months ended September 30, 2013 compared to the same period in 2012, electric operating revenues net of purchased power were lower due to the impact of unfavorable weather conditions in PECO s service territory.

During the nine months ended September 30, 2013 compared to the same period in 2012, operating revenues net of purchased power and fuel expense were higher due to the impact of favorable 2013 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 three and nine months ended September 30, 2013 compared to the same periods in 2012 and normal weather consisted of the following:

				% Change	
Heating and Cooling Degree-Days	**2013**	**2012**	**Normal**	**From 2012**	**From Normal**
Three Months Ended September 30,					
Heating Degree-Days	36	14	35	157.1%	2.9%
Cooling Degree-Days	928	1,138	934	(18.5)%	(0.6)%
Nine Months Ended September 30,					
Heating Degree-Days	2,897	2,265	2,974	27.9%	(2.6)%
Cooling Degree-Days	1,346	1,572	1,282	(14.4)%	5.0%

Volume

Electric operating revenues net of purchased power expense related to delivery volume, exclusive of the effects of weather, for the three months ended September 30, 2013 remained relatively level compared to the same period in 2012. The decrease in electric operating revenues net of purchased power expense related to delivery volume, exclusive of the effects of weather, for the nine months ended September 30, 2013 compared to the same period in 2012 reflected the impact of energy efficiency initiatives on customer usages partially offset by the oil refineries returning to full production in 2013.

Pricing

Nine Months Ended September 30, 2013 Compared to Nine Months Ended September 30, 2012. The decrease in electric operating revenues net of purchased power expense as a result of pricing is primarily attributable to lower overall effective rates due to increased usage per customer across all customer classes.

Regulatory Required Programs

This represents the change in operating revenues 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 offsetting costs of these programs are included in operating and maintenance expense, depreciation and amortization expense and income taxes. See the operating and maintenance expense discussion below for additional information on included programs.

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Gross Receipts Tax

GRT is an excise tax on total revenue. As a result of decreases in operating revenues for the three and nine months ended September 30, 2013 compared to the same periods in 2012, GRT decreased. Equal and offsetting decreases in GRT have been reflected in Taxes Other Than Income.

Other

The decrease in other electric revenues net of purchased power expense for the three and nine months ended September 30, 2013 compared to the same periods in 2012 reflected a decrease in wholesale transmission revenue earned by PECO due to higher peak loads in the previous years.

Operating and Maintenance Expense

	Three Months Ended September 30, 2013	Three Months Ended September 30, 2012	Increase (Decrease)	Nine Months Ended September 30, 2013	Nine Months Ended September 30, 2012	Increase (Decrease)
Operating and Maintenance Expense Baseline	$ 169	$ 170	$ (1)	$ 497	$ 505	$ (8)
Operating and Maintenance Expense Regulatory Required Programs(a)	17	29	(12)	57	69	(12)
Total Operating and Maintenance Expense	$ 186	$ 199	$ (13)	$ 554	$ 574	$ (20)

(a) Operating and maintenance expenses for regulatory required programs are costs for various legislative and/or regulatory programs that are recoverable from customers on a full and current basis through approved regulated rates. An equal and offsetting amount has been reflected in operating revenues.

The changes in operating and maintenance expense for the three and nine months ended September 30, 2013 compared to the same periods in 2012, consisted of the following:

	Three Months Ended September 30, Increase (Decrease)	Nine Months Ended September 30, Increase (Decrease)
Baseline		
Labor, other benefits, contracting and materials	$ (1)	$ 7
Storm-related costs	(3)	(2)
Injuries and Damages	3	(1)
Pension and non-pension postretirement benefits expense	(3)	(9)
Constellation merger and integration costs		(5)
Other	3	2
	(1)	(8)
Regulatory Required Programs		
Smart Meter	1	1
Energy Efficiency	(13)	(13)
	(12)	(12)
Increase (Decrease) in operating and maintenance expense	$ (13)	$ (20)

Depreciation and Amortization Expense

The increase in depreciation and amortization expense for the three and nine months ended September 30, 2013 compared to the same periods in 2012 was primarily due to ongoing capital expenditures as well as increased depreciation and amortization expense related to the smart meter AMI infrastructure. An equal and offsetting amount for the depreciation and amortization expense related to the smart meter AMI communications network has been reflected in operating revenues during the periods represented.

Taxes Other Than Income

The decrease in taxes other than income for the three months ended September 30, 2013 compared to the same period in 2012 was primarily due to decreased GRT collections as a result of lower operating revenues. An equal and offsetting decrease in GRT has been reflected in operating revenues during the current period.

Taxes other than income for the nine months ended September 30, 2013 compared to the same period in 2012 remained relatively level.

Interest Expense, Net

The decrease in interest expense, net for the three and nine months ended September 30, 2013 compared to the same periods in 2012 was primarily due to lower interest expense as a result of refinancing debt at lower interest rates during the second half of 2012.

Other, Net

The change in Other, net for the three and nine months ended September 30, 2013 remained relatively level compared to the same period in 2012.

Effective Income Tax Rate

PECO s effective income tax rate was 27.6% and 16.9% for the three months ended September 30, 2013 and 2012, respectively. The increase in the effective income tax rate is primarily due to the impact of the tax benefit recognized in 2012 related to the gas repairs deduction claimed on the 2011 tax return.

The effective income tax rate was 29.5% and 28.2% for the nine months ended September 30, 2013 and 2012, respectively. The increase in the effective tax rate reflects the impact of the tax benefit recognized in 2012 related to the gas repairs deduction claimed on the 2011 tax return with an offset of the gas repairs bill credit amortization which commenced in 2013. See Note 12 Income Taxes of the Combined Notes to the Consolidated Financial Statements for further discussion of the change in effective income tax rate.

PECO Electric Operating Statistics and Revenue Detail

Retail Deliveries to Customers (in GWhs)	Three Months Ended September 30, 2013	2012	% Change	Weather-Normal % Change	Nine Months Ended September 30, 2013	2012	% Change	Weather-Normal % Change
Retail Delivery and Sales(a)								
Residential	3,781	4,059	(6.8)%	0.3%	10,134	10,154	(0.2)%	0.0%
Small commercial & industrial	2,142	2,245	(4.6)%	(1.5)%	6,111	6,155	(0.7)%	(1.8)%
Large commercial & industrial	4,207	4,165	1.0%	2.9%	11,637	11,545	0.8%	2.2%
Public authorities & electric railroads	219	240	(8.8)%	(8.8)%	712	714	(0.3)%	(0.3)%
Total Electric Retail Deliveries	10,349	10,709	(3.4)%	0.8%	28,594	28,568	0.1%	0.4%

Number of Electric Customers	As of September 30, 2013	2012
Residential	1,419,837	1,416,894
Small commercial & industrial	148,843	148,829
Large commercial & industrial	3,114	3,103
Public authorities & electric railroads	9,666	9,666
Total	1,581,460	1,578,492

Electric Revenue	Three Months Ended September 30, 2013	2012	% Change	Nine Months Ended September 30, 2013	2012	% Change
Retail Delivery and Sales(a)						
Residential	$ 448	$ 497	(9.9)%	$ 1,197	$ 1,297	(7.7)%
Small commercial & industrial	109	120	(9.2)%	324	357	(9.2)%
Large commercial & industrial	53	66	(19.7)%	173	179	(3.4)%
Public authorities & electric railroads	7	8	(12.5)%	23	24	(4.2)%
Total Retail	617	691	(10.7)%	1,717	1,857	(7.5)%
Other Revenue(b)	55	61	(9.8)%	163	171	(4.7)%
Total Electric Revenues	$ 672	$ 752	(10.6)%	$ 1,880	$ 2,028	(7.3)%

(a) Reflects delivery volumes and revenues from customers purchasing electricity directly from PECO and customers purchasing electricity from a competitive electric generation supplier as all customers are assessed distribution charges. For customers purchasing electricity from PECO, revenue also reflects the cost of energy and transmission.
(b) Other revenue includes transmission revenue from PJM and wholesale electric revenues.

PECO Gas Operating Statistics and Revenue Detail

Deliveries to Customers (in mmcf)	Three Months Ended September 30, 2013	2012	% Change	Weather-Normal % Change	Nine Months Ended September 30, 2013	2012	% Change	Weather-Normal % Change
Retail Delivery and Sales								
Retail sales(a)	3,531	3,646	(3.2)%	(3.1)%	38,888	32,301	20.4%	(0.5)%
Transportation and other	6,041	5,796	4.2%	2.4%	20,880	19,397	7.6%	2.3%
Total Gas Deliveries	9,572	9,442	1.4%	0.2%	59,768	51,698	15.6%	0.5%

Number of Gas Customers	As of September 30, 2013	2012
Residential	455,809	452,624
Commercial & industrial	41,591	41,338
Total Retail	497,400	493,962
Transportation	909	900
Total	498,309	494,862

Gas Revenue	Three Months Ended September 30, 2013	2012	% Change	Nine Months Ended September 30, 2013	2012	% Change
Retail Delivery and Sales						
Retail sales(a)	$ 48	$ 49	(2.0)%	$ 386	$ 344	12.2%
Transportation and other	8	5	60.0%	29	24	20.8%
Total Gas Revenues	$ 56	$ 54	3.7%	$ 415	$ 368	12.8%

(a) Reflects delivery volumes and revenues from customers purchasing natural gas directly from PECO and customers purchasing natural gas from a competitive natural gas supplier as all customers are assessed distribution charges. For customers purchasing natural gas from PECO, revenue also reflects the cost of natural gas.

Results of Operations BGE

	Three Months Ended September 30,		Favorable (Unfavorable)	Nine Months Ended September 30,		Favorable (Unfavorable)
	2013	**2012**	**Variance**	**2013**	**2012**	**Variance**
Operating revenues	$ 737	$ 720	$ 17	$ 2,271	$ 2,032	$ 239
Purchased power and fuel	346	373	27	1,059	1,043	(16)
Revenue net of purchased power and fuel(a)	391	347	44	1,212	989	223
Other operating expenses						
Operating and maintenance	146	201	55	450	557	107
Depreciation and amortization	78	68	(10)	252	218	(34)
Taxes other than income	53	48	(5)	162	143	(19)
Total other operating expenses	277	317	40	864	918	54
Operating income	114	30	84	348	71	277
Other income and (deductions)						
Interest expense, net	(29)	(35)	6	(94)	(110)	16
Other, net	4	5	(1)	13	18	(5)
Total other income and (deductions)	(25)	(30)	5	(81)	(92)	11
Income (loss) before income taxes	89		89	267	(21)	288
Income taxes	36		(36)	107	(7)	(114)
Net income (loss)	53		53	160	(14)	174
Preference stock dividends	3	4	(1)	10	10	
Net income (loss) attributable to common shareholder	$ 50	$ (4)	$ 54	$ 150	$ (24)	$ 174

(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 shareholders

Three Months Ended September 30, 2013, Compared to Three Months Ended 2012. BGE s net income attributable to common shareholders for the three months ended September 30, 2013, was higher than the same period in 2012, primarily due to higher electric and gas distribution rates, effective February 23, 2013, pursuant to the MDPSC order in BGE s 2012 rate case and lower storm-related costs in 2013.

Nine Months Ended September 30, 2013, Compared to Nine Months Ended 2012. BGE s net income attributable to common shareholders for the nine months ended September 30, 2013, was higher than the same period in 2012, primarily due to decreased operating revenue net of purchased power and fuel expense in 2012 related to the accrual of the residential customer rate credit and decreased operating and maintenance expense related to the 2012 accrual of its portion of charitable contributions which, were conditions of the MDPSC s approval of Exelon s merger with Constellation. The increase in net income attributable to common shareholders was also driven by higher electric and gas distribution rates pursuant to the MDPSC order in BGE s 2012 rate case and lower storm-related costs in 2013.

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Operating Revenues, Purchased Power and Fuel Expense

There are certain drivers to operating revenue that are offset by their impact on purchased power expense and fuel expense, such as commodity procurement costs and programs allowing customers to select a competitive electric or natural gas supplier. Electric and gas revenues and purchased power and fuel expense are affected by fluctuations in commodity procurement costs. BGE s electric and natural gas rates charged to customers are subject to periodic adjustments that are designed to recover or refund the difference between the actual cost of purchased electric power and purchased natural gas and the amount included in rates in accordance with the MDPSC s market-based SOS and gas commodity programs, respectively.

The number of customers electing to select a competitive electric generation supplier affects electric SOS revenues and purchased power expense. The number of customers electing to select a competitive natural gas supplier affects gas cost adjustment revenues and purchased natural gas expense. All BGE customers have the choice to purchase energy from a competitive electric generation supplier. This customer choice of electric generation suppliers does not impact the volume of deliveries, but affects revenue collected from customers related to SOS. The number of retail customers purchasing electricity from a competitive electric generation supplier was 395,200 and 347,200 at September 30, 2013 and 2012, respectively, representing 32% and 28% of total retail customers, respectively. Retail deliveries purchased from competitive electric generation suppliers represented 62% and 61% of BGE's retail kWh sales for the three and nine months ended September 30, 2013, respectively compared to 59% and 60% for the three and nine months ended September 30, 2012, respectively. The number of retail customers purchasing natural gas from a competitive natural gas supplier was 167,700 and 132,800 at September 30, 2013 and 2012, respectively, representing 26% and 20% of total retail customers, respectively. Retail deliveries purchased from competitive natural gas suppliers represented 74% and 55% of BGE's retail mmcf sales for the three and nine months ended September 30, 2013, respectively, compared to 74% and 58% for the three and nine months ended September 30, 2012, respectively.

The changes in BGE s operating revenues net of purchased power and fuel expense for the three months ended September 30, 2013 compared to the same period in 2012, consisted of the following:

	Increase (Decrease)		
	Electric	**Gas**	**Total**
Pricing	$ 25	$ 2	$ 27
Regulatory required programs	9	1	10
Other	6	1	7
Total increase	$ 40	$ 4	$ 44

The changes in BGE s operating revenues net of purchased power and fuel expense for the nine months ended September 30, 2013 compared to the same period in 2012 consisted of the following:

	Increase (Decrease)		
	Electric	**Gas**	**Total**
Residential customer rate credit(a)	$ 82	$ 31	$ 113
Pricing	49	11	60
Regulatory required programs	27	5	32
Other	15	3	18
Total increase	$ 173	$ 50	$ 223

(a) In accordance with the MDPSC order approving Exelon s merger with Constellation, the residential customer rate credit is not recoverable from BGE s customers. Exelon made a $66 million equity contribution to BGE in the second quarter of 2012 to fund the after-tax amount of the rate credit as directed in the MDPSC order approving the merger transaction.

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

Heating 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 three and nine months ended September 30, 2013 compared to the same period in 2012 consisted of the following:

				% Change	
Heating and Cooling Degree-Days	**2013**	**2012**	**Normal**	**From 2012**	**From Normal**
Three Months Ended September 30,					
Heating Degree-Days	111	69	82	60.9%	35.4%
Cooling Degree-Days	567	698	588	(18.8)%	(3.6)%
Nine Months Ended September 30,					
Heating Degree-Days	3,054	2,344	2,983	30.3%	2.4%
Cooling Degree-Days	830	997	838	(16.8)%	(1.0)%

Residential Customer Rate Credit. The increase in operating revenues net of purchased power and fuel compared to the same period in 2012 was due to the residential customer rate credit provided in 2012 as a result of the MDPSC s order approving Exelon s merger with Constellation.

Pricing. The increase in operating revenues net of purchased power and fuel expense as a result of pricing for the three and nine months ended September 30, 2013 compared to the same period in 2012 primarily reflected the impact of the new electric and natural gas distribution rates charged to customers that became effective February 23, 2013 in accordance with the 2012 MDPSC approved electric and natural gas distribution rate case order. See Note 5 Regulatory Matters of the Combined Notes to the Consolidated Financial Statements for further information.

Regulatory Required Programs. This represents the change in revenues collected under approved riders to recover costs incurred for the energy efficiency and demand response programs as well as administrative and commercial and industrial customer bad debt costs for SOS. The riders are designed to provide full recovery, as well as a return in certain instances. The costs of these programs are included in operating and maintenance expense, depreciation and amortization expense and taxes other than income taxes. The increase in revenues during the three and nine months ended September 30, 2013 compared to the same period in 2012 was primarily due to the recovery of higher energy efficiency program costs.

Other. Other revenues increased during the three and nine months ended September 30, 2013 compared to the same period in 2012. Other revenues, which can vary from period to period, include miscellaneous revenues such as base distribution revenues, which increased due to a favorable change in the customer mix.

Operating and Maintenance Expense

The changes in operating and maintenance expense for the three and nine months ended September 30, 2013 compared to the same periods in 2012, consisted of the following:

	Three Months Ended September 30,	Nine Months Ended September 30,
	Increase (Decrease)	Increase (Decrease)
Charitable contributions accrual(a)	$	$ (28)
Merger costs(b)	1	(21)
Corporate Allocations	(8)	(8)
Storm-related costs	(42)	(37)
Labor, other benefits, contracting and materials	(12)	(8)
Other	6	(5)
Decrease in operating and maintenance expense	$ (55)	$ (107)

(a) In accordance with the MDPSC order approving Exelon s merger with Constellation, the charitable contribution accrual is not recoverable from BGE s customers.

(b) BGE established a regulatory asset of $6 million at March 31, 2013 for certain 2012 other merger integration costs as part of the 2013 electric and gas distribution rate case order.

Depreciation and Amortization

The increases in depreciation and amortization expense for the three and nine months ended September 30, 2013 compared to the same periods in 2012 were primarily due to higher amortization expense related to energy efficiency and demand response programs, which are fully offset in revenues above, and higher property, plant and equipment balances resulting from ongoing capital expenditures.

Taxes Other Than Income

The increases in taxes other than income for the three and nine months ended September 30, 2013 compared to the same periods in 2012 were primarily due to an increase in payroll taxes and increased GRT collections.

Interest Expense, Net

The decreases in interest expense, net for the three and nine months ended September 30, 2013 compared to the same periods in 2012 were primarily due to the interest recorded in 2012 on prior year tax liabilities and lower effective interest rates as a result of refinancing debt at a lower interest rate in 2013.

Other, Net

The decrease in other, net for the three and nine months ended September 30, 2013 compared to the same periods in 2012 was primarily due to decreased AFUDC-Equity and investment income. See Note 19 Supplemental Financial Information of the Combined Notes to Consolidated Financial Statements for further details of the components of other, net.

Effective Income Tax Rate

BGE s effective income tax rate was 40.4% and 0.0% for the three months ended September 30, 2013 and 2012, respectively, and 40.1% and 33.3% for the nine months ended September 30, 2013 and 2012, respectively. See Note 12 Income Taxes of the Combined Notes to Consolidated Financial Statements for further discussion of the change in effective income tax rate.

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BGE Electric Operating Statistics and Revenue Detail

Retail Deliveries to Customers (in GWhs)	Three Months Ended September 30, 2013	2012	% Change	Weather-Normal % Change	Nine Months Ended September 30, 2013	2012	% Change	Weather-Normal % Change
Retail Delivery and Sales(a)								
Residential	3,557	3,830	(7.1)%	n.m	9,849	9,693	1.6%	n.m
Small commercial & industrial	808	881	(8.3)%	n.m	2,301	2,316	(0.6)%	n.m
Large commercial & industrial	3,882	3,996	(2.9)%	n.m	11,046	11,578	(4.6)%	n.m
Public authorities & electric railroads	78	91	(14.3)%	n.m	239	249	(4.0)%	n.m
Total Electric Retail Deliveries	8,325	8,798	(5.4)%	n.m	23,435	23,836	(1.7)%	n.m

Number of Electric Customers	As of September 30, 2013	2012
Residential	1,119,209	1,115,764
Small commercial & industrial	112,988	113,312
Large commercial & industrial	11,634	11,566
Public authorities & electric railroads	293	319
Total	1,244,124	1,240,961

Electric Revenue	Three Months Ended September 30, 2013	2012	% Change	Nine Months Ended September 30, 2013	2012	% Change
Retail Delivery and Sales(a)						
Residential	$ 390	$ 400	(2.5)%	$ 1,056	$ 960	10.0%
Small commercial & industrial	72	70	2.9%	197	194	1.5%
Large commercial & industrial	116	106	9.4%	333	302	10.3%
Public authorities & electric railroads	8	7	14.3%	23	22	4.5%
Total Retail	586	583	0.5%	1,609	1,478	8.9%
Other Revenue	78	64	21.9%	203	176	15.3%
Total Electric Revenues	$ 664	$ 647	2.6%	$ 1,812	$ 1,654	9.6%

(a) Reflects delivery revenues and volumes from customers purchasing electricity directly from BGE and customers purchasing electricity from a competitive electric generation suppliers as all customers are assessed delivery charges. For customers purchasing electricity from BGE, revenue also reflects the cost of energy and transmission.

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BGE Gas Operating Statistics and Revenue Detail

Deliveries to Customers (in mmcf)	Three Months Ended September 30, 2013	2012	% Change	Weather-Normal % Change	Nine Months Ended September 30, 2013	2012	% Change	Weather-Normal % Change
Retail Delivery and Sales(b)								
Retail sales	10,642	11,147	(4.5)%	n.m.	65,854	60,613	8.6%	n.m.
Transportation and other	933	2,311	(59.6)%	n.m.	8,128	12,606	(35.5)%	n.m.
Total Gas Deliveries	11,575	13,458	(14.0)%	n.m.	73,982	73,219	1.0%	n.m.

Number of Gas Customers	As of September 30, 2013	2012
Residential	612,065	610,353
Commercial & industrial	44,028	43,978
Total	656,093	654,331

Gas Revenue	Three Months Ended September 30, 2013	2012	% Change	Nine Months Ended September 30, 2013	2012	% Change
Retail Delivery and Sales						
Retail sales	$ 66	$ 63	4.8%	$ 412	$ 334	23.4%
Transportation and other(b)	7	10	(30.0)%	47	44	6.8%
Total Gas Revenues	$ 73	$ 73	0.0%	$ 459	$ 378	21.4%

(b) Transportation and other gas revenue includes off-system revenue of 933 mmcfs ($5 million) and 2,311 mmcfs ($8 million) for the three months ended September 30, 2013 and 2012, respectively, and 8,128 mmcfs ($37 million) and 12,606 mmcfs ($37 million) for the nine months ended September 30, 2013 and 2012, respectively.

Liquidity and Capital Resources

Exelon s and Generation s prior year activity presented below includes the activity of Constellation, and BGE in the case of Exelon, from the merger effective date of March 12, 2012 through September 30, 2012. BGE prior year activity presented below includes its activity for the nine months ended September 30, 2012.

The Registrants operating and capital expenditures requirements are provided by internally generated cash flows from operations as well as funds from external sources in the capital markets and through bank borrowings. The Registrants businesses are capital intensive and require considerable capital resources. Each Registrant s access to external financing on reasonable terms depends on its credit ratings and current overall capital market business conditions, including that of the utility industry in general. If these conditions deteriorate to the extent that the Registrants no longer have access to the capital markets at reasonable terms, Exelon, Generation, ComEd, PECO and BGE have access to unsecured revolving credit facilities with aggregate bank commitments of $0.5 billion, $5.3 billion, $1.0 billion, $0.6 billion and $0.6 billion, respectively. The Registrants revolving credit facilities expire in 2018. In addition, Generation has $0.4 billion in bilateral facilities with banks. The bilateral facilities at Generation have expirations in January 2015, December 2015 and March 2016. The Registrants utilize their credit facilities to support their commercial paper programs, provide for other short-term borrowings and 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 11 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 5 Regulatory Matters and 18 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 take effect in 2013. The estimated impacts of the law are reflected in the projected pension contributions below.

Exelon has contributed $255 million to its qualified pension plans in 2013, of which Generation, ComEd, PECO and BGE contributed $113 million, $115 million, $11 million and $0 million, respectively. 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 $82 million in 2013, of which Generation, ComEd, PECO, and BGE will make payments of $7 million, $1 million, $0 million, and $2 million, respectively.

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 plans are not subject to regulatory minimum contribution requirements. Exelon s management considers 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 regulator expectations and best assure continued recovery). In 2013, Exelon anticipates funding its other postretirement benefit plans based on the funding considerations discussed above, with the exception of those plans previously sponsored by Constellation and AmerGen, which remain unfunded. Exelon expects to make other postretirement benefit plan contributions, including benefit payments related to unfunded plans, of approximately $276 million in 2013, of which Generation, ComEd, PECO, and BGE expect to contribute $108 million, $112 million, $21 million, and $17 million, respectively.

Tax Matters

The Registrants future cash flows from operating activities may be affected by the following tax matters:

Exelon expects to receive a Federal refund of approximately $345 million between 2013 and 2014 which will be paid to ComEd, PECO, BGE and Generation of approximately $320 million, $10 million, $20 million, and $25 million, respectively.

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.

The following table provides a summary of the major items affecting Exelon s cash flows from operations for the nine months ended September 30, 2013 and 2012:

	Nine Months Ended September 30, 2013	Nine Months Ended September 30, 2012	Variance
Net income	$ 1,235	$ 787	$ 448
Add (subtract):			
Non-cash operating activities(a)	3,094	4,166	(1,072)
Pension and other postretirement benefit contributions	(360)	(131)	(229)
Income taxes	863	465	398
Changes in working capital and other noncurrent assets and liabilities(b)	(327)	(999)	672
Option premiums paid, net	(38)	(122)	84
Counterparty collateral (posted) received, net	(73)	408	(481)
Net cash flows provided by operations	$ 4,394	$ 4,574	$ (180)

(a) Represents depreciation, amortization and accretion, impairment of long-lived assets, mark-to-market gains and losses on derivative transactions, deferred income taxes, provision for uncollectible accounts, pension and other postretirement benefit expense, equity in losses of unconsolidated affiliates and investments, decommissioning-related items, stock compensation expense and other non-cash charges.

(b) Changes in working capital and other noncurrent assets and liabilities exclude the changes in commercial paper, income taxes and the current portion of long-term debt.

Cash flows provided by operations for the nine months ended September 30, 2013 and 2012 by Registrant were as follows:

	Nine Months Ended September 30, 2013	Nine Months Ended September 30, 2012
Exelon	$ 4,394	$ 4,574
Generation	2,657	3,013
ComEd	850	1,181
PECO	620	628

BGE	433	340

Changes in Exelon s, Generation s, ComEd s, PECO s and BGE s cash flows from operations were generally consistent with changes in each Registrant s respective results of operations, as adjusted by changes in working capital in the normal course of business. In addition, significant operating cash flow impacts for the Registrants for the nine months ended September 30, 2013 and 2012 were as follows:

Generation

During the nine months ended September 30, 2013 and 2012, Generation had net (payments) receipts of counterparty collateral of $(123) million and $315 million, respectively. Net (payments) receipts during the nine months ended September 30, 2013 and 2012 were primarily due to market conditions that resulted in changes to Generation s net mark-to-market position. Depending upon whether Generation is in a net mark-to-market liability or asset position, collateral may be required to be posted with or collected from its counterparties. This collateral may be in various forms, such as cash, which may be obtained through the issuance of commercial paper, or letters of credit.

During the nine months ended September 30, 2013 and 2012, Generation had net payments of approximately $(38) million and $(122) million, respectively, related to purchases and sales of options. The level of option activity in a given period may vary due to several factors, including changes in market conditions as well as changes in hedging strategy.

ComEd

During the nine months ended September 30, 2013 and 2012, ComEd s net payables to Generation for energy purchases related to its supplier forward contract, ICC-approved RFP contracts and financial swap contract settlements decreased by $22 million and $17 million, respectively. During the nine months ended September 30, 2013 and 2012, ComEd s payables to other energy suppliers for energy purchases increased (decreased) by $69 million and $(14) million, respectively.

During the nine months ended September 30, 2013 and 2012, $50 million and $90 million, respectively, of incremental cash collateral posted with PJM was returned to ComEd. On September 4, 2012, all $120 million of ComEd cash collateral posted with PJM was replaced with a Letter of Credit. The net incremental change to collateral posted at PJM for the nine months ended September 30, 2012 was an increase of $30 million. The Letter of Credit was replaced with $53 million cash in November 2012. ComEd s collateral posted with PJM has decreased due to lower PJM billings resulting from lower load being served by ComEd due to increased switching activity primarily driven by municipal aggregation. As of September 30, 2013 and 2012, ComEd had $3 million and $120 million, respectively, of collateral posted with PJM.

PECO

During the nine months ended September 30, 2013 and 2012, PECO s payables to Generation for energy purchases decreased by $26 million and increased by $14 million, respectively, and payables to other electric and gas suppliers for energy purchases increased by $22 million and decreased by $30 million, respectively.

BGE

During the nine months ended September 30, 2013 and 2012, BGE s payables to Generation for energy purchases increased by $9 million and $3 million, respectively, and payables to other electric and gas suppliers for energy purchases decreased by $16 million and decreased by $27 million, respectively.

Cash Flows from Investing Activities

Cash flows used in investing activities for the nine months ended September 30, 2013 and 2012 by Registrant were as follows:

	Nine Months Ended September 30, 2013	Nine Months Ended September 30, 2012
Exelon	$ (3,970)	$ (3,342)
Generation	(2,149)	(2,056)
ComEd	(1,042)	(871)
PECO	(368)	(259)
BGE	(409)	(430)

Capital expenditures by Registrant for the nine months ended September 30, 2013 and 2012 and projected amounts for the full year 2013 are as follows:

	Projected Full Year 2013(d)	Nine Months Ended September 30, 2013	Nine Months Ended September 30, 2012
Exelon	$ 5,450	$ 3,887	$ 4,162
Generation(a)	2,725	1,995	2,602
ComEd(b)	1,450	1,074	896
PECO	550	374	274
BGE	625	391	419
Other(c)	100	53	38

(a) Includes nuclear fuel.
(b) The projected capital expenditures include approximately $263 million of expected incremental spending pursuant to EIMA, which 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.
(c) Other primarily consists of corporate operations and BSC.
(d) Total projected capital expenditures do not include adjustments for non-cash activity.

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

Generation

Approximately 37% and 19% of the projected 2013 capital expenditures at Generation are for the acquisition of nuclear fuel and investments in renewable energy generation, including Antelope Valley construction costs, respectively, with the remaining amounts reflecting additions and upgrades to existing facilities (including material condition improvements during nuclear refueling outages). Also included in the projected 2013 capital expenditures are a portion of the costs of a series of planned power uprates across Generation s nuclear fleet, adjusted during the second quarter of 2013 to reflect the cancellation of certain nuclear power uprate projects during 2013. See EXELON CORPORATION Executive Overview, for more information on nuclear uprates.

ComEd, PECO and BGE

Approximately 90%, 88% and 79% of the projected 2013 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 and for PECO and BGE, capital expenditures related to their respective smart meter program and SGIG project, net of DOE expected reimbursements. The remaining amounts are for capital additions to support new business and customer growth.

In 2010, NERC provided guidance to transmission owners that recommends ComEd, PECO and BGE perform assessments of all their transmission lines, with the highest priority lines assessed by December 31, 2011, medium priority lines by December 31, 2012, and the lowest priority lines by December 31, 2013. In compliance with this guidance, ComEd, PECO and BGE submitted their most recent bi-annual reports to NERC in July 2013. 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 2013 capital expenditures above reflect capital spending for remediation to be completed in 2013.

ComEd, PECO and BGE anticipate that they will fund their capital expenditures with internally generated funds and borrowings, including ComEd s capital expenditures associated with EIMA as further discussed in Note 5 Regulatory Matters of the Combined Notes to Consolidated Financial Statements.

Cash Flows from Financing Activities

Cash flows provided by (used in) financing activities for the nine months ended September 30, 2013 and 2012 by Registrant were as follows:

	Nine Months Ended September 30,	
	2013	**2012**
Exelon	$ (266)	$ (548)
Generation	(251)	(623)
ComEd	82	(513)
PECO	(5)	85
BGE	(106)	162

Debt

See Note 11 Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for further details of the Registrants debt issuances and retirements.

Dividends

Cash dividend payments and distributions during the nine months ended September 30, 2013 and 2012 by Registrant were as follows:

	Nine Months Ended September 30,	
	2013	**2012**
Exelon	$ 981	$ 1,226
Generation	550	1,384
ComEd	165	95
PECO	249	261
BGE(a)	10	10

(a) Relates to dividends paid on BGE s preference stock.

Revised Dividend Policy

On February 6, 2013, the Exelon Board of Directors approved a revised dividend policy which contemplates a regular $0.31 per share quarterly dividend on Exelon s common stock payable beginning in the second quarter of 2013 (or $1.24 per share on an annualized basis), subject to quarterly declarations by the Exelon Board of Directors.

First Quarter 2013 Dividend

On February 6, 2013, the Exelon Board of Directors declared a regular quarterly dividend, paid on March 8, 2013 of $0.525 per share on Exelon s common stock.

Second Quarter 2013 Dividend

On April 23, 2013, the Exelon Board of Directors declared a regular quarterly dividend, paid on June 10, 2013 of $0.310 per share on Exelon s common stock.

Third Quarter 2013 Dividend

On July 23, 2013, the Exelon Board of Directors declared a regular quarterly dividend, paid on September 10, 2013 of $0.310 per share on Exelon s common stock.

Fourth Quarter 2013 Dividend

On October 22, 2013, the Exelon Board of Directors declared a regular quarterly dividend, payable on December 10, 2013 of $0.310 per share on Exelon s common stock

Short-Term Borrowings

During the nine months ended September 30, 2013, ComEd issued $153 million of commercial paper, BGE issued $40 million of commercial paper and Generation issued $21 million in short-term notes payable. During the nine months ended September 30, 2012, Exelon issued $146 million of commercial paper, ComEd issued $35 million of commercial paper and Generation repaid $25 million in short-term notes payable.

Contributions from Parent/Member

During the nine months ended September 30, 2013, there were no contributions from Parent/Member (Exelon). During the nine months ended September 30, 2012, Exelon contributed $66 million to BGE to fund the after-tax amount of the residential customer rate credit as directed in the MDPSC order approving the merger transaction.

Other

For the nine months ended September 30, 2013, other financing activities primarily consisted of expenses paid related to the replacement of the Registrants credit facilities. See Note 11 of the Combined Notes to Consolidated Financial Statements for additional information.

Credit Matters

The Registrants fund liquidity needs for capital investment, working capital, energy hedging and other financial commitments through cash flows from continuing operations, public debt offerings, commercial paper markets and large, diversified credit facilities. The credit facilities include $8.4 billion in aggregate total commitments of which $6.8 billion was available as of September 30, 2013, and of which no financial institution has more than 8% of the aggregate commitments. Exelon, Generation, ComEd, PECO and BGE had access to the commercial paper market during the third quarter of 2013 to fund their short-term liquidity needs, when necessary. The Registrants routinely review the sufficiency of their liquidity position, including appropriate sizing of credit facility commitments, by performing various stress test scenarios, such as commodity price movements, increases in margin-related transactions, changes in hedging levels and the impacts of hypothetical credit downgrades. The Registrants have continued to closely monitor events in the financial markets and the financial institutions associated with the credit facilities, including monitoring credit ratings and outlooks, credit default swap levels, capital raising and merger activity. See PART I. ITEM 1A. RISK FACTORS of Exelon s 2012 Annual Report on Form 10-K for further information regarding the effects of uncertainty in the capital and credit markets or significant bank failures.

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 September 30, 2013, it would have been required to provide incremental collateral of $1.8 billion of collateral obligations for derivatives, non-derivatives, normal purchase normal sales contracts and applicable payables and receivables, net of the contractual right of offset under master netting agreements, which is well within its current available credit facility capacities of $4.3 billion. If ComEd lost its investment grade credit rating as of September 30, 2013, it would have been required to provide incremental collateral of $18 million, which is well within its current available credit facility capacity of $847 million, which takes into account commercial paper borrowings as of September 30, 2013. If PECO lost its investment grade credit rating as of September 30, 2013, it would be required to provide collateral of $3 million pursuant to PJM s credit policy and could have been required to provide collateral of $30 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 September 30, 2013, it would have been required to provide collateral of $2 million pursuant to PJM s credit policy and could have been required to provide collateral of $41 million related to its natural gas procurement contracts, which, in the aggregate, are well within BGE s current available credit facility capacity of $560 million.

Exelon Credit Facilities

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. The Registrants may use their respective credit facilities for general corporate purposes, including meeting short-term funding requirements and the issuance of letters of credit. See Note 11 Debt and Credit Agreements of the Combined Notes to the Consolidated Financial Statements for further information regarding the Registrants credit facilities.

The following table reflects the Registrants commercial paper programs supported by the revolving credit agreements and bilateral credit agreements at September 30, 2013:

Commercial Paper Programs

Commercial Paper Issuer	**Maximum Program Size**	**Outstanding Commercial Paper at September 30, 2013**	**Average Interest Rate on Commercial Paper Borrowings for the Nine Months Ended September 30, 2013**
Exelon Corporate	$ 500	$	0.27%
Generation	5,600		0.32%
ComEd	1,000	153	0.39%
PECO	600		
BGE	600	40	0.27%

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In order to maintain their respective commercial paper programs in the amounts indicated above, each Registrant must have credit facilities in place, at least equal to the amount of its commercial paper program. While the amount of its commercial paper outstanding does not reduce available capacity under a Registrant s credit agreement, a Registrant does not issue commercial paper in an aggregate amount exceeding the available capacity under its credit agreement.

Credit Agreements

					Available Capacity at September 30, 2013	
Borrower	**Facility Type**	**Aggregate Bank Commitment(a)**	**Facility Draws**	**Outstanding Letters of Credit**	**Actual**	**To Support Additional Commercial Paper**
Exelon Corporate	Syndicated Revolver	$ 500	$	$ 2	$ 498	$ 498
Generation	Syndicated Revolver	5,300		968	4,332	4,332
Generation	Bilaterals	375		374	1	1
ComEd	Syndicated Revolver	1,000			1,000	847
PECO	Syndicated Revolver	600		1	599	599
BGE	Syndicated Revolver	600			600	560

(a) Excludes $123 million of credit facility agreements arranged with minority and community banks at Generation, ComEd, PECO and BGE. These facilities expire on October 18, 2014, and are solely utilized to issue letters of credit. See Note 11 of the Combined Notes to the Consolidated Financial Statements for further information.

On January 23, 2013, Generation entered into a two year $75 million bilateral letter of credit facility with a bank. The credit agreement expires in January 2015. This facility will solely be utilized by Generation to issue letters of credit.

On March 14, 2013, ComEd extended its unsecured revolving credit facility with aggregate bank commitments of $1.0 billion. Under this facility, ComEd may issue letters of credit in the aggregate amount of up to $500 million. The credit agreement expires on March 28, 2018, and ComEd may request another one-year extension of that term. The credit facility also allows ComEd to request increases in the aggregate commitments of up to an additional $500 million. Any such extension or increases are subject to the approval of the lenders party to the credit agreement in their sole discretion. Costs incurred to extend the facility for ComEd were not material.

On August 10, 2013, Exelon Corporate, Generation, PECO and BGE amended and extended their respective unsecured syndicated revolving credit facilities, with aggregate bank commitments of $500 million, $5.3 billion, $600 million and $600 million, respectively. The new covenants are substantially consistent with existing covenants. Costs incurred to amend and extend the facilities for Exelon Corporate, Generation, PECO and BGE were not material.

Effective August 10, 2013, Exelon and ComEd entered into amendments to each of their respective revolving credit facilities (the Amendments). The Amendments relate to the IRS s challenge to the position taken by Exelon on its 1999 federal income tax return with respect to the sale of ComEd s fossil generating assets in a like-kind exchange tax position. The Amendments are intended to exclude the non-cash impact of the like-kind exchange tax position from the calculation of the interest coverage ratio under each of Exelon and ComEd s respective credit facilities. See Note 12 Income Taxes for additional information.

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 registrants credit rating. Exelon Corporate, Generation, ComEd, PECO and BGE have adders of 27.5, 27.5, 27.5, 0.0 and 7.5

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basis points for prime based borrowings and 127.5, 127.5, 127.5, 100.0 and 107.5 basis points for LIBOR-based borrowings. The maximum adders for prime rate borrowings and LIBOR-based rate borrowings are 65 basis points and 165 basis points, respectively. The credit agreements also require the borrower to pay a facility fee based upon the aggregate commitments under the agreement. The fee varies depending upon the respective credit ratings of the borrower.

On October 18, 2013, Generation, ComEd, PECO and BGE replaced their respective minority and community bank credit facility agreements in the amounts of $50 million, $34 million, $34 million and $5 million, respectively. These facilities, which expire in October 2014, are solely utilized to issue letters of credit.

Each revolving credit agreement for Exelon, Generation, ComEd, PECO and BGE 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 following table summarizes the minimum thresholds reflected in the credit agreements for the nine months ended September 30, 2013:

	Exelon	Generation	ComEd	PECO	BGE
Credit agreement threshold	2.50 to 1	3.00 to 1	2.00 to 1	2.00 to 1	2.00 to 1

At September 30, 2013, the interest coverage ratios at the Registrants were as follows:

	Exelon	Generation	ComEd	PECO	BGE
Interest coverage ratio	5.90	13.18	5.04	8.49	7.00

An event of default under any Registrant s credit facility will not constitute an event of default under any of the other Registrants credit facilities, except that a bankruptcy or other event of default in the payment of principal, premium or indebtedness in principal amount in excess of $100 million in the aggregate by Generation under its credit facility will constitute an event of default under the Exelon corporate credit facility.

Security Ratings

The Registrants access to the capital markets, including the commercial paper market, and their respective financing costs in those markets, may depend on the securities ratings of the entity that is accessing the capital markets.

The Registrants borrowings are not subject to default or prepayment as a result of a downgrading of securities, although such a downgrading of a Registrant s securities could increase fees and interest charges under that Registrant s credit agreements.

As part of the normal course of business, the Registrants enter into contracts that contain express provisions or otherwise permit the Registrants and their counterparties to demand adequate assurance of future performance when there are reasonable grounds for doing so. In accordance with the contracts and applicable contracts law, if the Registrants are downgraded by a credit rating agency, 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, which could include the posting of collateral. See Note 10 Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information on collateral provisions.

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 participant during the nine months ended September 30, 2013, in addition to the net contribution or borrowing as of September 30, 2013, are presented in the following table:

Contributed (borrowed) as of September 30, 2013	Maximum Contributed	Maximum Borrowed	Contributed (Borrowed)
Generation	$	$ 435	$
PECO	304		1
BSC		229	(218)
Exelon Corporate	237	N/A	217

Investments in Nuclear Decommissioning Trust Funds

Exelon and Generation maintain trust funds, as required by the NRC, to fund certain costs of decommissioning Generation s nuclear plants. The mix of securities in the trust funds is designed to provide returns to be used to fund decommissioning and to offset inflationary increases in decommissioning costs. Generation actively monitors the investment performance of the trust funds and periodically reviews asset allocations in accordance with Generation s NDT fund investment policy. Generation s investment policy establishes limits on the concentration of holdings in any one company and also in any one industry. See Note 13 Nuclear Decommissioning 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

On May 29, 2012, the Registrants filed a combined shelf registration statement unlimited in amount, with the SEC, which became immediately effective and remained effective as of September 30, 2013. 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

On March 1, 2013, ComEd received $470 million in long-term debt new money authority from the ICC and on February 27, 2012, ComEd received $1.3 billion in long-term debt refinancing authority from the ICC. As of September 30, 2013, ComEd had $1.3 billion available in long-term debt refinancing authority and $218 million available in new money long-term debt financing authority from the ICC. As of September 30, 2013, PECO had $1.4 billion available in long-term debt financing authority from the PAPUC. As of September 30, 2013, BGE had $850 million available in long-term financing authority from MDPSC.

As of September 30, 2013, ComEd and PECO had short-term financing authority from FERC, which expires on December 31, 2013, of $2.5 billion and $1.5 billion, respectively. BGE had short-term financing authority from FERC, which expires December 31, 2014, of $0.7 billion. Generation currently has blanket financing authority it received from FERC in connection with its market-based rate authority. On October 29, 2013, ComEd and PECO filed applications with FERC for renewal of its short-term financing authority through December 31, 2015. On October 31, 2013, BGE filed an application with FERC for renewal of its short-term financing authority through December 31, 2015. ComEd, PECO and BGE expect approval of the application before the end of the year.

Contractual Obligations and Off-Balance Sheet Arrangements

Contractual obligations represent cash obligations that are considered to be firm commitments and commercial commitments triggered by future events. See Note 18 Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for discussion of the Registrants commitments.

Generation, ComEd, PECO and BGE have obligations related to contracts for the purchase of power and fuel supplies, and ComEd, PECO and BGE have obligations related to their financing trusts. The power and fuel purchase contracts and the financing trusts have been considered for consolidation in the Registrants respective financial statements pursuant to the authoritative guidance for VIEs. See Note 1 Basis of Presentation of the Combined Notes to Consolidated Financial Statements for further information.

For an in-depth discussion of the Registrant s contractual obligations and off-balance sheet arrangements, see Management s Discussion and Analysis of Financial Condition and Results of Operations Contractual Obligations and Off-Balance Sheet Arrangements in the Exelon 2012 Form 10-K.

Item 3. Quantitative and Qualitative Disclosures about Market Risk

The Registrants are exposed to market risks associated with adverse changes in commodity prices, counterparty credit, interest rates and equity prices. Exelon s RMC approves risk management policies and objectives for risk assessment, control and valuation, counterparty credit approval, and the monitoring and reporting of risk exposures. The RMC is chaired by the chief risk officer and includes the chief executive officer, chief financial officer, corporate controller, general counsel, treasurer, vice president of strategy, vice president of audit services and officers representing Exelon s business units. The RMC reports to the Risk Oversight Committee of the Exelon Board of Directors on the scope of the risk management activities. The following discussion serves as an update to ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK of the Registrants 2012 Annual Report on Form 10-K incorporated herein by reference.

Commodity Price Risk (Exelon, Generation, ComEd, PECO and BGE)

Commodity price risk is associated with price movements resulting from changes in supply and demand, fuel costs, market liquidity, weather conditions, governmental regulatory and environmental policies, and other factors. To the extent the amount of energy Exelon generates differs from the amount of energy it has contracted to sell, Exelon has price risk from commodity price movements. Exelon seeks to mitigate its commodity price risk through the sale and purchase of electricity, fossil fuel, and other commodities.

Generation

Normal Operations and Hedging Activities. Electricity available from Generation s owned or contracted generation supply in excess of Generation s obligations to customers, including portions of ComEd s, PECO s and BGE s retail load, is sold into the wholesale markets. To reduce price risk caused by market fluctuations, Generation enters into non-derivative contracts as well as derivative contracts, including forwards, futures, swaps, and options, with approved counterparties to hedge anticipated exposures. Generation believes these instruments represent economic hedges that mitigate exposure to fluctuations in commodity prices. Generation expects the settlement of the majority of its economic hedges will occur during 2013 through 2015. Generation s energy contracts are accounted for under the accounting guidance for derivatives as further discussed in Note 10 Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements.

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 September 30, 2013, the percentage of expected generation hedged for the major reportable segments was 97%-100%, 84%-87% and 48%-51% for 2013, 2014 and 2015, respectively. The percentage of expected generation hedged is the amount of equivalent sales divided by the expected generation. Expected generation represents the amount of energy estimated to be generated or purchased through owned or contracted capacity. Equivalent sales represent all hedging products, which include economic hedges and certain non-derivative contracts including sales to ComEd, PECO and BGE to serve their retail load.

A portion of Generation s hedging strategy may be accomplished with fuel products based on assumed correlations between power and fuel prices, which routinely change in the market. Market price risk exposure is the risk of a change in the value of unhedged positions. The forecasted market price risk exposure for Generation s entire non-trading portfolio associated with a $5 reduction in the annual average around-the-clock energy price based on September 30, 2013 market conditions and hedged position would be an immaterial change in pre-tax income for 2013 and a decrease in pre-tax net income of approximately $150 million and $630 million, respectively, for 2014 and 2015. 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 2,499 GWhs and 6,066 GWhs for the three and nine months ended September 30, 2013, respectively, and 4,352 GWhs and 9,981 GWhs for the three and nine months ended September 30, 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 nine months ended September 30, 2013 resulted in pre-tax gains of $13 million due to net mark-to-market losses of $35 million and realized gains of $48 million. Generation uses a 95% confidence interval, assuming standard normal distribution, one day holding period, one-tailed statistical measure in calculating its VaR. The daily VaR on proprietary trading activity averaged $ 1.4 million of exposure during the quarter. 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 nine months ended September 30, 2013 of $5,564 million.

Fuel Procurement. Generation procures coal and natural gas through long-term and short-term contracts, and spot-market purchases. Nuclear fuel assemblies are obtained primarily through long-term contracts for uranium concentrates, and long-term contracts for conversion services, enrichment services and fuel fabrication services. The supply markets for coal, natural gas, uranium concentrates and certain nuclear fuel services are subject to price fluctuations and availability restrictions. Supply market conditions may make Generation s procurement contracts subject to credit risk related to the potential non-performance of counterparties to deliver the contracted commodity or service at the contracted prices. Approximately 60% of Generation s uranium concentrate requirements from 2013 through 2017 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 18 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 s RFP contracts are deemed to be derivatives that qualify for the normal purchases and normal sales exception under derivative accounting guidance. ComEd does not enter into derivatives for speculative or trading purposes. ComEd is permitted full recovery of its RFP contracts from retail customers with no mark-up.

On December 17, 2010, ComEd entered into several 20-year floating-to-fixed energy swap contracts with unaffiliated suppliers regarding the procurement of long-term renewable energy and associated RECs. 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 Notes 5 and 10 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 5 Regulatory Matters of the Combined Notes to the Consolidated Financial Statements. PECO has certain full requirements contracts and block contracts that are considered derivatives and qualify for the normal purchases and normal sales scope exception under current derivative authoritative guidance. 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 10 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. 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 10 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 mark-to-market net asset or liability balance sheet position from December 31, 2012 to September 30, 2013. It indicates the drivers behind changes in the balance sheet amounts. This table incorporates the mark-to-market activities that are immediately recorded in earnings as well as the settlements from OCI to earnings and changes in fair value for the cash flow hedging activities that are recorded in accumulated OCI on the Consolidated Balance Sheets. This table excludes all normal purchase and normal sales contracts and does not segregate proprietary trading activity. See Note 10 Derivative Financial Instruments of the Combined Notes to the Consolidated Financial

Statements for additional information on the balance sheet classification of the mark-to-market energy contract net assets (liabilities) recorded as of September 30, 2013 and December 31, 2012.

	Generation	ComEd	Intercompany Eliminations(b)	Exelon
Total mark-to-market energy contract net assets (liabilities) at December 31, 2012(a)	$ 1,505	$ (293)	$	$ 1,212
Total change in fair value during 2013 of contracts recorded in result of operations	224		(6)	218
Reclassification to realized at settlement of contracts recorded in results of operations	12		13	25
Reclassification to realized at settlement from accumulated OCI(c)	(543)		219	(324)
Changes in fair value energy derivatives(d)		171	(226)	(55)
Changes in allocated collateral	115			115
Changes in net option premium paid/(received)	38			38
Option premium amortization(e)	(87)			(87)
Other balance sheet reclassifications	(9)			(9)
Total mark-to-market energy contract net assets (liabilities) at September 30, 2013(a)	$ 1,255	$ (122)	$	$ 1,133

(a) Amounts are shown net of collateral paid to and received from counterparties.
(b) Amounts related to five-year financial swap between Generation and ComEd are eliminated in consolidation.
(c) For Generation, includes $ 219 million of losses from reclassifications from accumulated OCI to recognize gains in net income related to settlement of the five-year financial swap contract with ComEd for the nine months ended September 30, 2013.
(d) For ComEd, the changes in fair value are recorded as a change in regulatory assets or liabilities. As of September 30, 2013, ComEd recorded a $122 million regulatory asset related to its mark-to-market derivative liabilities with Generation and unaffiliated suppliers. As of September 30, 2013, this included $11 million of decreases in fair value and $215 million for reclassifications from regulatory asset to recognize cost in purchased power expense due to settlements of ComEd's five-year financial swap with Generation. As of September 30, 2013, ComEd also recorded $57 million of increases in fair value and $4 million of realized losses due to settlements associated with floating-to-fixed energy swap contracts with unaffiliated suppliers.
(e) Includes $87 million of amounts reclassified to realized at the settlement of contracts recorded to results of operations related to option premiums due to the settlement of the underlying transactions for the nine months ended September 30, 2013.

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 9 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						
	2013	2014	2015	2016	2017	2018 and Beyond	Total Fair Value
Normal Operations, Commodity derivative contracts(a)(b):							
Actively quoted prices (Level 1)	$ (34)	$ (84)	$ (32)	$ 15	$	$ (1)	$ (136)
Prices provided by external sources (Level 2)	176	524	195	35			930
Prices based on model or other valuation methods (Level 3)(c)	(7)	215	116	66	30	(81)	339
Total	$ 135	$ 655	$ 279	$ 116	$ 30	$ (82)	$ 1,133

(a) Mark-to-market gains and losses on 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 $146 million at September 30, 2013.
(c) Includes ComEd's net assets (liabilities) associated with the floating-to-fixed energy swap contracts with unaffiliated suppliers.

Generation

	Maturities Within						
	2013	2014	2015	2016	2017	2018 and Beyond	Total Fair Value
Normal Operations, Commodity derivative contracts(a)(b):							
Actively quoted prices (Level 1)	$ (34)	$ (84)	$ (32)	$ 15	$	$ (1)	$ (136)
Prices provided by external sources (Level 2)	176	524	195	35			930
Prices based on model or other valuation methods (Level 3)	(2)	232	134	83	46	(32)	461
Total	$ 140	$ 672	$ 297	$ 133	$ 46	$ (33)	$ 1,255

(a) Mark-to-market gains and losses on 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 $146 million at September 30, 2013.

ComEd

	Maturities Within						
	2013	2014	2015	2016	2017	2018 and beyond	Total Fair Value
Prices based on model or other valuation methods(a)	$ (5)	$ (17)	$ (18)	$ (17)	$ (16)	$ (49)	$ (122)

(a) Represents ComEd's net liabilities associated with the floating-to-fixed energy swap contracts with unaffiliated suppliers.

Credit Risk, Collateral, and Contingent Related Features (Exelon, Generation, ComEd, PECO and BGE)

The Registrants would be exposed to credit-related losses in the event of non-performance by counterparties that enter into derivative instruments. The credit exposure of derivative contracts, before collateral, is represented by the fair value of contracts at the reporting date. See Note 10 Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for a detail discussion of credit risk, collateral, and contingent related features.

Generation

The following tables provide information on Generation s credit exposure for all derivative instruments, normal purchase normal sales agreements, and applicable payables and receivables, net of collateral and instruments that are subject to master netting agreements, as of September 30, 2013. The tables further delineate that exposure by credit rating of the counterparties and provide guidance on the concentration of credit risk to individual counterparties and an indication of the duration of a company s credit risk by credit rating of the counterparties. The figures in the tables below do not include credit risk exposure from uranium procurement contracts or exposure through RTOs, ISOs, NYMEX, ICE and Nodal commodity exchanges, which are discussed below. Additionally, the figures in the tables below do not include exposures with affiliates, including net receivables with ComEd, PECO and BGE of $33 million, $30 million and $39 million, respectively. See Note 22 Related Party Transactions of the Exelon 2012 Form 10-K for further information.

Rating as of September 30, 2013	**Total Exposure Before Credit Collateral**	**Credit Collateral(a)**	**Net Exposure**	**Number of Counterparties Greater than 10% of Net Exposure**	**Net Exposure of Counterparties Greater than 10% of Net Exposure**
Investment grade	$ 1,767	$ 191	$ 1,576	1	$ 478
Non-investment grade	16	9	7		
No external ratings					
Internally rated investment grade	472	6	466	1	238
Internally rated non-investment grade	18	1	17		
Total	$ 2,273	$ 207	$ 2,066	2	$ 716

	Maturity of Credit Risk Exposure			
Rating as of September 30, 2013	**Less than 2 Years**	**2-5 Years**	**Exposure Greater than 5 Years**	**Total Exposure Before Credit Collateral**
Investment grade	$ 1,268	$ 355	$ 144	$ 1,767
Non-investment grade	14	2		16
No external ratings				
Internally rated investment grade	312	154	6	472
Internally rated non-investment grade	18			18
Total	$ 1,612	$ 511	$ 150	$ 2,273

Net Credit Exposure by Type of Counterparty	**As of September 30, 2013**
Investor-owned utilities, marketers and power producers	$ 743
Energy cooperatives and municipalities	916
Financial institutions	355
Other	52
Total	$ 2,066

(a)

As of September 30, 2013, credit collateral held from counterparties where Generation had credit exposure included $180 million of cash and $27 million of letters of credit.

ComEd

There have been no significant changes or additions to ComEd s exposures to credit risk that are described in ITEM 1A. RISK FACTORS of Exelon s 2012 Annual Report on Form 10-K.

See Note 10 of the Combined Notes to Consolidated Financial Statements for information regarding credit exposure to suppliers.

PECO

There have been no significant changes or additions to PECO s exposures to credit risk as described in ITEM 1A. RISK FACTORS of Exelon s 2012 Annual Report on Form 10-K.

See Note 10 Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for information regarding credit exposure to suppliers.

BGE

There have been no significant changes or additions to BGE s exposures to credit risk as described in ITEM 1A. RISK FACTORS of Exelon s 2012 Annual Report on Form 10-K.

See Note 10 Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for information regarding credit exposure to suppliers.

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

Generation

As part of the normal course of business, Generation routinely enters into physical or financial contracts for the sale and purchase of electricity, fossil fuel and other commodities. These contracts either contain express provisions or otherwise permit Generation and its counterparties to demand adequate assurance of future performance when there are reasonable grounds for doing so. In accordance with the contracts and applicable law, if Generation is downgraded by a credit rating agency, especially if such downgrade is to a level below investment grade, it is possible that a counterparty would attempt to rely on such a downgrade as a basis for making a demand for adequate assurance of future performance. Depending on Generation s net position with a counterparty, the demand could be for the posting of collateral. In the absence of expressly agreed-to provisions that specify the collateral that must be provided, collateral requested will be a function of the facts and circumstances of the situation at the time of the demand. In this case, Generation believes an amount of several months of future payments (i.e. capacity payments) rather than a calculation of fair value is the best estimate for the contingent collateral obligation, which has been factored into the disclosure below. See Note 10 of the Combined Notes to Consolidated Financial Statements for information regarding collateral requirements.

Generation sells output through bilateral contracts. The bilateral contracts are subject to credit risk, which relates to the ability of counterparties to meet their contractual payment obligations. Any failure to collect these payments from counterparties could have a material impact on Exelon s and Generation s results of operations, cash flows and financial position. As market prices rise above contracted price levels, Generation is required to post collateral with purchasers; as market prices fall below contracted price levels, counterparties are required to post collateral with Generation. In order to post collateral, Generation depends on access to bank credit facilities, which serve as liquidity sources to fund collateral requirements. See Note 11 of the Combined Notes to Consolidated Financial Statements for additional information.

As of September 30, 2013, Generation had cash collateral posted of $353 million and cash collateral held of $202 million for counterparties with derivative positions, of which $146 million in net cash collateral deposits was offset against mark-to-market assets and liabilities. As of September 30, 2013, $5 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. See Note 18 of the Combined Notes to Consolidated Financial Statements for information regarding the letters of credit supporting the cash collateral.

ComEd

As of September 30, 2013, ComEd held immaterial amounts of cash and letters of credit for the purpose of collateral from suppliers in association with energy procurement contracts and held approximately $19 million in the form of cash and letters of credit for both annual and long-term renewable energy contracts. See Notes 5 Regulatory Matters and 10 Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for further information.

PECO

As of September 30, 2013, PECO was not required to post collateral under its energy and natural gas procurement contracts. See Note 10 Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for further information.

BGE

BGE is not required to post collateral under its electric supply contracts. As of September 30, 2013, BGE was not required to post collateral under its natural gas procurement contracts, nor was it holding collateral under its electric supply and natural gas procurement contracts. See Note 10 of the Combined Notes to Consolidated Financial Statements for further information.

RTOs and ISOs (Exelon, Generation, ComEd, PECO and BGE)

Generation, ComEd, PECO and BGE participate in all, or some, of the established, real-time energy markets that are administered by PJM, ISO-NE, ISO-NY, CAISO, MISO, SPP, AESO, OIESO and ERCOT. In these areas, power is traded through bilateral agreements between buyers and sellers and on the spot markets that are operated by the RTOs or ISOs, as applicable. In areas where there is no spot market, electricity is purchased and sold solely through bilateral agreements. For sales into the spot markets administered by an RTO or ISO, the RTO or ISO maintains financial assurance policies that are established and enforced by those administrators. The credit policies of the RTOs and ISOs may, under certain circumstances, require that losses arising from the default of one member on spot market transactions be shared by the remaining participants. Non-performance or non-payment by a major counterparty could result in a material adverse impact on the Registrants results of operations, cash flows and financial positions.

Exchange Traded Transactions (Exelon and Generation)

Generation enters into commodity transactions on NYMEX, ICE and the Nodal exchange. The NYMEX, ICE and Nodal exchange clearinghouses act as the counterparty to each trade. Transactions on the NYMEX, ICE and Nodal exchange must adhere to comprehensive collateral and margining requirements. As a result, transactions on NYMEX, ICE and Nodal exchange are significantly collateralized and have limited counterparty credit risk.

Long-Term Leases (Exelon)

Exelon s consolidated balance sheets, as of September 30, 2013, included a $691 million net investment in coal-fired plants in Georgia and Texas subject to long-term leases. This investment represents the estimated residual value of leased assets at the end of the respective lease terms of $1,465 million, less unearned income of $774 million. The lease agreements provide the lessees with fixed purchase options at the end of the lease terms. If the lessees do not exercise the fixed purchase options, Exelon has the ability to require the lessees to return the leasehold interests or to arrange for a third party to bid on a service contract for a period following the lease term. If Exelon chooses the service contract option, the leasehold interests will be returned to Exelon at the end of the term of the service contract. In any event, Exelon will be subject to residual value risk if the lessees do not exercise the fixed purchase options. This risk is partially mitigated by the fair value of the scheduled payments under the service contract. However, such payments are not guaranteed. Further, the term of the service contract is less than the expected remaining useful life of the plants and, therefore, Exelon s exposure to residual value risk will not be mitigated by payments under the service contract in this remaining period. Lessee performance under the lease agreements is supported by collateral and credit enhancement measures. Management regularly evaluates the creditworthiness of Exelon s counterparties to these long-term leases. Exelon monitors the continuing credit quality of the credit enhancement party.

Pursuant to the applicable accounting guidance, Exelon is required to review the estimated residual values of its direct financing lease investments at least annually and, if the review indicates a fair value below the carrying value and the decline is determined to be other than temporary, must record an impairment charge in the period the estimate changed. Based on the review performed in the second quarter of 2013, the estimated residual value of one of Exelon s direct financing leases experienced an other than temporary decline resulting in a $14 million pre-tax impairment charge in the second quarter of 2013. See Note 7 of the Combined Notes to Consolidated Financial Statements for further information.

Interest Rate Risk (Exelon, Generation, ComEd, PECO and BGE)

The Registrants use a combination of fixed-rate and variable-rate debt to manage interest rate exposure. The Registrants may also utilize fixed-to-floating interest rate swaps, which are typically designated as fair value hedges, as a means to manage their interest rate exposure. In addition, the Registrants may utilize interest rate derivatives to lock in rate levels in anticipation of future financings, which are typically designated as cash flow hedges. These strategies are employed to manage interest rate risks. At September 30, 2013, Exelon had $1,250 million of notional amounts of fixed-to-floating hedges outstanding and $213 million of notional amounts of floating-to-fixed hedges outstanding. Assuming the fair value and cash flow interest rate hedges are 100% effective, a hypothetical 50 bps increase in the interest rates associated with unhedged variable-rate debt (excluding Commercial Paper) and fixed-to-floating swaps would result in less than $1 million decrease in Exelon Consolidated pre-tax income for the nine months ended September 30, 2013.

Equity Price Risk (Exelon and Generation)

Exelon and Generation maintain trust funds, as required by the NRC, to fund certain costs of decommissioning Generation s nuclear plants. As of September 30, 2013, Generation s decommissioning trust funds are reflected at fair value on its Consolidated Balance Sheets. The mix of securities in the trust funds is designed to provide returns to be used to fund decommissioning and to compensate Generation for inflationary increases in decommissioning costs; however, the equity securities in the trust funds are exposed to price fluctuations in equity markets, and the value of fixed-rate, fixed-income securities are exposed to changes in interest rates. Generation actively monitors the investment performance of the trust funds and periodically reviews asset allocation in accordance with Generation s NDT fund investment policy. A hypothetical 10% increase in interest rates and decrease in equity prices would result in a $444 million reduction in the fair value of the trust assets. This calculation holds all other variables constant and assumes only the discussed changes in interest rates and equity prices. See ITEM 2. 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.

Item 4. Controls and Procedures

During the third quarter of 2013, each of Exelon s, Generation s, ComEd s, PECO s and BGE s management, including its principal executive officer and principal financial officer, evaluated its disclosure controls and procedures related to the recording, processing, summarizing and reporting of information in its periodic reports that it files with the SEC. These disclosure controls and procedures have been designed by all Registrants to ensure that (a) material information relating to that Registrant, including its consolidated subsidiaries, is accumulated and made known to Exelon s management, including its principal executive officer and principal financial officer, by other employees of that Registrant and its subsidiaries as appropriate to allow timely decisions regarding required disclosure, and (b) this information is recorded, processed, summarized, evaluated and reported, as applicable, within the time periods specified in the SEC s rules and forms. Due to the inherent limitations of control systems, not all misstatements may be detected. These inherent limitations include the realities that judgments in decision-making can be faulty and that breakdowns can occur because of simple error or mistake. Additionally, controls could be circumvented by the individual acts of some persons or by collusion of two or more people.

Accordingly, as of September 30, 2013, the principal executive officer and principal financial officer of each of Exelon, Generation, ComEd, PECO and BGE concluded that such Registrant s disclosure controls and procedures were effective to accomplish its objectives. All Registrants continually strive to improve its disclosure controls and procedures to enhance the quality of its financial reporting and to maintain dynamic systems that change as conditions warrant. There have been no changes in internal control over financial reporting that occurred during the third quarter of 2013 that have materially affected, or are reasonably likely to materially affect, any of Exelon s, Generation s, ComEd s, PECO s and BGE s internal control over financial reporting.

PART II OTHER INFORMATION

Item 1. Legal Proceedings

The Registrants are parties to various lawsuits and regulatory proceedings in the ordinary course of their respective businesses. For information regarding material lawsuits and proceedings, see (a) ITEM 3. LEGAL PROCEEDINGS of Exelon s 2012 Form 10-K and (b) Notes 4, 5 and 18 of the Combined Notes to Consolidated Financial Statements in PART I, ITEM 1. FINANCIAL STATEMENTS of this Report. Such descriptions are incorporated herein by these references.

Item 1A. Risk Factors

Risks Related to Exelon

At September 30, 2013, the Registrants risk factors were consistent with the risk factors described in Exelon s 2012 on Form 10-K.

Item 4. Mine Safety Disclosures

Exelon, Generation, ComEd, PECO and BGE

Not applicable to the Registrants.

Item 6. Exhibits

Certain of the following exhibits are incorporated herein by reference under Rule 12b-32 of the Securities and Exchange Act of 1934, as amended. Certain other instruments which would otherwise be required to be listed below have not been so listed because such instruments do not authorize securities in an amount which exceeds 10% of the total assets of the applicable registrant and its subsidiaries on a consolidated basis and the relevant registrant agrees to furnish a copy of any such instrument to the Commission upon request.

Exhibit No.	Description
4.1	Supplemental Indenture dated as of August 1, 2013 from Commonwealth Edison Company to BNY Mellon Trust Company of Illinois, as trustee, and D.G. Donovan, as co-trustee, relating to the issuance of $350 million of First Mortgage 4.60% Bonds, Series 114, due August 15, 2043 (File No. 001-1839, Form 8-K dated August 19, 2013, Exhibit No. 4.1)
4.2	One Hundred and Ninth Supplemental Indenture dated as of September 15, 2013 from PECO Energy Company to U.S. Bank National Association, as trustee, relating to the issuance of $300 million of First and Refunding Mortgage Bonds, 1.200% Series due October 15, 2016 (File No. 000-16844, Form 8-K dated September 23, 2013, Exhibit 4.1)
4.3	One Hundred and Tenth Supplemental Indenture dated as of September 15, 2013 from PECO Energy Company to U.S. Bank National Association, as trustee, relating to the issuance of $250 million of First and Refunding Mortgage Bonds, 4.800% Series due October 15, 2043 (File No. 000-16844, Form 8-K dated September 23, 2013, Exhibit 4.2)
4.4	Indenture, dated as of September 30, 2013, among Continental Wind, LLC, the guarantors party thereto and Wilmington Trust, National Association, as trustee (File No. 333-85496, Form 8-K dated September 30, 2013, Exhibit No. 4.1)
4.5	Form of 6.000% Senior Secured Notes due 2033 (File No. 333-85496, Form 8-K dated September 30, 2013, Exhibit No. 4.2)

Exhibit No.	Description
10.1	Amendment No. 3 to Credit Agreement dated as of March 23, 2011 among Exelon Corporation, as Borrower, the various financial institutions named therein, as Lenders, and JPMorgan Chase Bank, N.A., as Administrative Agent (File No. 001-16169, Form 8-K dated August 10, 2013, Exhibit No. 99-1)
10.2	Amendment No. 1 to Credit Agreement dated as of March 28, 2012 among Commonwealth Edison Company, as Borrower, the various financial institutions named therein, as Lenders, and JPMorgan Chase Bank, N.A., as Administrative Agent (File No. 001-1839, Form 8-K dated August 10, 2013, Exhibit No. 99-2)
101.INS	XBRL Instance
101.SCH	XBRL Taxonomy Extension Schema
101.CAL	XBRL Taxonomy Extension Calculation
101.DEF	XBRL Taxonomy Extension Definition
101.LAB	XBRL Taxonomy Extension Labels
101.PRE	XBRL Taxonomy Extension Presentation

Certifications Pursuant to Rule 13a-14(a) and 15d-14(a) of the Securities and Exchange Act of 1934 as to the Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2013 filed by the following officers for the following companies:

31-1	Filed by Christopher M. Crane for Exelon Corporation
31-2	Filed by Jonathan W. Thayer for Exelon Corporation
31-3	Filed by Kenneth W. Cornew for Exelon Generation Company, LLC
31-4	Filed by Bryan P. Wright for Exelon Generation Company, LLC
31-5	Filed by Anne R. Pramaggiore for Commonwealth Edison Company
31-6	Filed by Joseph R. Trpik, Jr. for Commonwealth Edison Company
31-7	Filed by Craig L. Adams for PECO Energy Company
31-8	Filed by Phillip S. Barnett for PECO Energy Company
31-9	Filed by Kenneth W. DeFontes, Jr. for Baltimore Gas and Electric Company
31-10	Filed by Carim V. Khouzami for Baltimore Gas and Electric Company

Certifications Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code (Sarbanes Oxley Act of 2002) as to the Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2013 filed by the following officers for the following companies:

32-1	Filed by Christopher M. Crane for Exelon Corporation
32-2	Filed by Jonathan W. Thayer for Exelon Corporation
32-3	Filed by Kenneth W. Cornew for Exelon Generation Company, LLC
32-4	Filed by Bryan P. Wright for Exelon Generation Company, LLC
32-5	Filed by Anne R. Pramaggiore for Commonwealth Edison Company
32-6	Filed by Joseph R. Trpik, Jr. for Commonwealth Edison Company
32-7	Filed by Craig L. Adams for PECO Energy Company
32-8	Filed by Phillip S. Barnett for PECO Energy Company
32-9	Filed by Kenneth W. DeFontes, Jr. for Baltimore Gas and Electric Company
32-10	Filed by Carim V. Khouzami for Baltimore Gas and Electric Company

SIGNATURES

Pursuant to requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

EXELON CORPORATION

/s/ CHRISTOPHER M. CRANE Christopher M. Crane President and Chief Executive Officer (Principal Executive Officer)	/s/ JONATHAN W. THAYER Jonathan W. Thayer Executive Vice President and Chief Financial Officer (Principal Financial Officer)
/s/ DUANE M. DESPARTE Duane M. DesParte Senior Vice President and Corporate Controller (Principal Accounting Officer)	

November 6, 2013

Pursuant to requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

EXELON GENERATION COMPANY, LLC

/s/ KENNETH W. CORNEW Kenneth W. Cornew President and Chief Executive Officer (Principal Executive Officer)	/s/ BRYAN P. WRIGHT Bryan P. Wright Chief Financial Officer (Principal Financial Officer)
/s/ ROBERT M. AIKEN Robert M. Aiken Chief Accounting Officer (Principal Accounting Officer)	

November 6, 2013

Pursuant to requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

COMMONWEALTH EDISON COMPANY

/s/ ANNE R. PRAMAGGIORE Anne R. Pramaggiore President and Chief Executive Officer (Principal Executive Officer)	/s/ JOSEPH R. TRPIK, JR. Joseph R. Trpik, Jr. Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)
/s/ GERALD J. KOZEL Gerald J. Kozel	

Vice President and Controller

(Principal Accounting Officer)
November 6, 2013

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Pursuant to requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

PECO ENERGY COMPANY

/s/ CRAIG L. ADAMS Craig L. Adams President and Chief Executive Officer (Principal Executive Officer)	/s/ PHILLIP S. BARNETT Phillip S. Barnett Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)
/s/ SCOTT A. BAILEY Scott A. Bailey Vice President and Controller (Principal Accounting Officer)	

November 6, 2013

Pursuant to requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

BALTIMORE GAS AND ELECTRIC COMPANY

/s/ KENNETH W. DEFONTES, JR. Kenneth W. DeFontes, Jr. President and Chief Executive Officer (Principal Executive Officer)	/s/ CARIM V. KHOUZAMI Carim V. Khouzami Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)
/s/ DAVID M. VAHOS David M. Vahos Vice President and Controller (Principal Accounting Officer)	

November 6, 2013