
meeting the challenge
Exelon Corporation 05 Financial Information

April 6, 2006

Dear Shareholder:

I am pleased to present you Exelon’s 2005 Financial Information:

Exelon again reported strong financial and operating results for 2005. We are now the most highly valued company in the industry. Our success is attributable to continued operating improvements and careful financial management, as well as rising energy prices. While we face challenges in both Illinois and New Jersey, they arise from our continuing effort to advance competition, and ultimately the interests of our customers and the fortunes of our shareholders. I remain confident that we will meet these challenges.

The proxy statement and voting materials for the 2006 annual meeting of shareholders will be delivered to you, under separate cover, later next month.

Thank you for your continued support of Exelon Corporation.

John W. Rowe
Chairman, President and CEO

CORPORATE PROFILE

Exelon Corporation is one of the nation's largest electric utilities with approximately 5.2 million customers and more than $15 billion in annual revenues. The company has one of the industry's largest portfolios of electricity generation capacity, with a nationwide reach and strong positions in the Midwest and Mid-Atlantic. Exelon distributes electricity to approximately 5.2 million customers in northern Illinois and Pennsylvania and gas to more than 470,000 customers in Southeastern Pennsylvania. Exelon is headquartered in Chicago and trades on the NYSE under the ticker symbol EXC.

INVESTOR AND GENERAL INFORMATION

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Exelon Corporation
P.O. Box 805398
Chicago, IL 60680-5398

Independent Public Accountants
PricewaterhouseCoopers LLP

Website
www.exeloncorp.com

New York Stock Exchange Listing
EXC

Shareholder Inquiries
Computershare Trust Company, N.A., is Dividend Disbursing Agent, Dividend Reinvestment Agent and Transfer Agent for all classes of Exelon Corporation Stock.

Should you have questions or requests concerning your account, payment of dividends, the dividend reinvestment plan or transfer of stock, you may call toll-free, 1.800.626.8729. You may also mail your inquiry to Exelon Corporation c/o Computershare Trust Company, N.A., Post Office Box 43069, Providence, RI 02940-3069.

The Company had approximately 161,000 holders of record of its common stock as of December 31, 2005.

The Company maintains a telephone information service, which enables shareholders to obtain currently available information on financial performance, company news and shareholder services. To use this service, please call our toll-free number, 1.866.530.8108.

FINANCIAL INFORMATION SUPPLEMENT

The information included within this Financial Information supplement has been taken from Exelon Corporation's (Exelon) Form 10-K annual report for the year ended December 31, 2005. That annual report was filed with the Securities and Exchange Commission on February 15, 2006 and can be viewed and retrieved through the Commission's web site at www.sec.gov or our web site at www.exeloncorp.com. We encourage you to consider the entire Form 10-K annual report, which contains more information about us and our subsidiaries than is presented in this Financial Information supplement.

FORWARD-LOOKING STATEMENTS

Certain of the matters discussed in this Financial Information supplement are forward-looking statements, within the meaning of the Private Securities Litigation Reform Act of 1995, that are subject to risks and uncertainties. The factors that could cause actual results to differ materially from the forward-looking statements made by Exelon include those factors discussed herein or in Exelon's 2005 Form 10-K, including those discussed in (a) Risk Factors, (b) Management's Discussion and Analysis of Financial Condition and Results of Operation, (c) Financial Statements and Supplementary Data: Note 20, and (d) other factors discussed in filings with the United States Securities and Exchange Commission (SEC) by Exelon. Readers are cautioned not to place undue reliance on these forward-looking statements, which apply only as of the date of this Financial Information supplement. Exelon does not undertake any obligation to publicly release any revision to its forward-looking statements to reflect events or circumstances after the date of this Financial Information supplement.

WHERE TO FIND MORE INFORMATION

Exelon's 2005 Form 10-K is available on Exelon's website at *www.exeloncorp.com* and will be made available, without charge, in print to any shareholder who requests the document from Katherine K. Combs, Vice President and Corporate Secretary, Exelon Corporation, P.O. Box 805398, Chicago, Illinois 60680-5398.

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GENERAL DESCRIPTION OF OUR BUSINESS

General

Exelon, a public utility holding company, operates through its principal subsidiaries—Commonwealth Edison Company (ComEd), PECO Energy Company (PECO) and Exelon Generation Company, LLC (Generation)—as described below, each of which is treated as an operating segment by Exelon. In 2004, Exelon identified three operating segments—Energy Delivery (ComEd and PECO), Generation and Enterprises. Exelon sold or wound down substantially all components of Exelon Enterprises Company, LLC (Enterprises) in 2004 and 2003. As a result, Exelon ceased reporting Enterprises as a segment as of January 1, 2005. Additionally, Exelon concluded during the fourth quarter of 2005 that ComEd and PECO could no longer be aggregated as a combined Energy Delivery segment. As such, Exelon now presents three reportable segments: ComEd, PECO and Generation. Prior period presentation has been adjusted for comparative purposes. See Note 22 of Exelon's Notes to Consolidated Financial Statements for further segment information.

Exelon was incorporated in Pennsylvania in February 1999. Exelon's principal executive offices are located at 10 South Dearborn Street, Chicago, Illinois 60603, and its telephone number is 312-394-7398.

Proposed Merger with Public Service Enterprise Group Incorporated

On December 20, 2004, Exelon entered into an Agreement and Plan of Merger (Merger Agreement) with Public Service Enterprise Group Incorporated (PSEG), an exempt public utility holding company primarily located and serving customers in New Jersey, whereby PSEG will be merged with and into Exelon (Merger). PSEG shareholders approved the Merger on July 19, 2005. Exelon shareholders approved the issuance of Exelon shares pursuant to the Merger on July 22, 2005. Under the Merger Agreement, each share of PSEG common stock will be converted into 1.225 shares of Exelon common stock. As of December 31, 2005, PSEG's market capitalization exceeded $16 billion. Additionally, at December 31, 2005, PSEG, on a consolidated basis, had approximately $13 billion of outstanding debt, which is currently anticipated to become part of Exelon's consolidated debt.

In 2005, Exelon filed petitions or applications for approval or review of the Merger, or approval of matters related to the Merger, with various federal and state regulatory authorities, including the Federal Energy Regulatory Commission (FERC) under the Federal Power Act, the United States Department of Justice under the Hart Scott Rodino Antitrust Improvements Act of 1976, the Pennsylvania Public Utility Commission (PAPUC), the New Jersey Board of Public Utilities (NJBPU), the United States Nuclear Regulatory Commission (NRC), the New York Public Service Commission, the Connecticut Siting Council, the New Jersey Department of Environmental Protection (NJDEP) and the Public Utility Commission of Texas under the Texas Public Utility Regulatory Act. Various other state and Federal agencies and agencies of foreign countries have a role in reviewing various aspects of the transaction. ComEd filed a notice of the Merger with the Illinois Commerce Commission (ICC) and the ICC's general counsel confirmed that its formal approval of the Merger is not required.

As of February 14, 2006, all material regulatory approvals or reviews necessary to complete the Merger have been completed with the exception of the approval from the NJBPU and the NRC and the review by the United States Department of Justice.

The FERC approved the Merger on June 30, 2005. Exelon and PSEG proposed in their application with the FERC, and FERC approved, a market concentration mitigation plan involving the divestiture of 4,000 MW of coal, mid-merit (or intermediate) and peaking generation in the PJM region and the ongoing auction of 2,600 MW of nuclear output and the interim mitigation of fossil generation pending divestiture. Exelon and PSEG also proposed to invest a total of $25 million in transmission improvements, which was included in the proposal that was accepted by FERC. The ultimate outcome of the market concentration mitigation is dependent upon various factors, including the market conditions and buyer interest at the time the generating units and the nuclear output are offered for sale. The results of these activities, therefore, are not assured, and could have a material impact on the results of operations and cash flows of Exelon and Generation if the sales price for the divested assets is different from management's expectations. The FERC considered petitions for rehearing with respect to the order approving the Merger and affirmed its order on December 15, 2005. On January 6 and January 13, 2006, Philadelphia Gas Works/City of Philadelphia and subsidiaries of PPL Corporation, parties to the FERC proceeding, filed petitions for review of the FERC order in the United States Court of Appeals for the District of Columbia.

On January 27, 2006, the PAPUC approved the Merger and a partial settlement regarding PECO's distribution and transmission rates through 2010 and other financial commitments of PECO related to the Merger. The settlement reflected the conclusion of a process involving the majority of PECO customer groups during which PECO's cost data, return on equity and estimated Merger synergies were reviewed. The provisions of the PAPUC order and partial settlement are contingent upon the completion of the Merger. The PAPUC order and partial settlement require PECO to implement rate reductions aggregating $120 million during a four-year period and to cap its rates through the end of 2010. During the rate cap period, the PAPUC retains the right to lower PECO's rates if they are found to be excessive, and PECO retains the right to seek rate increases if certain events (such as significant increases in Federal or state income taxes or other significant changes in law or regulation that do not allow PECO to earn a fair rate of return) occur. The partial settlement also provides substantial funding for alternative energy and environmental projects, economic development, and expanded outreach and assistance for low-income customers. PECO also made commitments for enhanced customer service and reliability, commitments for charitable giving and employment, and a pledge to maintain its Philadelphia headquarters for a period of time. The total of these funding commitments is approximately $44 million, of which $30 million will be expensed at the time the Merger is completed. By separate motion, the PAPUC also indicated its intent to initiate a separate investigation, to which PECO had agreed in the partial settlement, to examine issues related to a potential combination of Philadelphia Gas Works, which provides gas distribution service in the City of Philadelphia, into Exelon's gas distribution businesses. This investigation will commence no earlier than 30 days after the close of the Merger. The outcome of this potential examination is uncertain. However, Exelon does not believe that the PAPUC has the authority to compel such a transaction if the two parties do not agree to terms through arms length negotiations.

On September 30, 2005, the administrative law judge in the proceeding before the NJBPU amended a prior prehearing order to modify the timetable for the regulatory approval process in New Jersey. The revised procedural schedule for the Merger review called for testimony to be filed from mid-November to mid-December and for hearings in January 2006. Under that revised schedule, the initial decision of the administrative law judge was expected in March 2006 and a final order from the full NJBPU was expected in May 2006. On January 25, 2006, the schedule for hearings was extended through March 27, 2006. On February 8, 2006, the administrative law judge approved a revised schedule calling for additional hearings on March 13, 14, 24 and 27, 2006. The dates originally scheduled for the administrative law judge's initial decision and the final order of the full NJBPU will also be extended but no firm dates have been set. Settlement discussions in New Jersey began in December 2005 and are expected to resume after completion of hearings before the NJBPU. Exelon will attempt to reach a settlement that satisfactorily resolves issues and allows the Merger to close in the second quarter of 2006. However, in the absence of an earlier settlement, Exelon expects that the closing of the Merger will occur in the third quarter of 2006.

Various governmental, consumer and other parties have intervened in the proceedings before the NJBPU and other regulatory bodies. To facilitate approval of the Merger, Exelon may negotiate with these parties and may enter into settlement agreements. Orders resulting from the proceedings before the NJBPU and other regulatory bodies and settlements in connection with the proceedings could, for example, affect the extent to which Exelon and its subsidiaries may benefit from expected synergies following the Merger and could be materially different from what they expect in this and other respects, and could have a material impact on Exelon's financial condition, results of operations and cash flows if the Merger is completed.

The Merger Agreement contains certain termination rights for both Exelon and PSEG, and further provides that, upon termination of the Merger Agreement under specified circumstances, (i) Exelon may be required to pay PSEG a termination fee of $400 million plus PSEG's transaction expenses up to $40 million or (ii) PSEG may be required to pay Exelon a termination fee of $400 million plus Exelon's transaction expenses up to $40 million. Either Exelon or PSEG can terminate the Merger Agreement without penalty if the closing of the Merger does not occur on or before June 20, 2006; however, this termination right is not available to a party whose failure to fulfill any obligation under the Merger Agreement resulted in the failure to close the Merger by June 20, 2006.

Further information concerning the proposed Merger is included in the definitive joint proxy statement/prospectus filed by Exelon with the SEC on June 3, 2005 under SEC Rule 424(b)(3) (Registration No. 333-122704). For additional information related to the Merger, see Management's Discussion and Analysis of Financial Condition and Results of Operation—Executive Overview—Proposed Merger with PSEG and Note 3 of Exelon's Notes to Consolidated Financial Statements. Except as otherwise specifically stated, any estimates for 2006 or thereafter disclosed in this Financial Information supplement do not reflect the effects of the Merger. In addition, PSEG and certain of its subsidiaries are reporting companies under the Securities Exchange Act of 1934, and their periodic reports and other filings are available on the web site maintained by the SEC at *http://www.sec.gov*. The information contained in the SEC filings of PSEG and its subsidiaries shall not be deemed incorporated into, or to be a part of, this Financial Information supplement.

ComEd

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

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

PECO

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

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

Generation

Exelon's generation business consists of the owned and contracted-for electric generating facilities and energy marketing operations of Generation, a 49.5% interest in two power stations in Mexico and the competitive retail sales business of Exelon Energy Company (Exelon Energy).

Generation was formed in 2000 as a Pennsylvania limited liability company. Generation began operations as a result of a corporate restructuring effective January 1, 2001 in which Exelon separated its generation and other competitive businesses from its regulated energy delivery business at ComEd and PECO. Generation's principal executive offices are located at 300 Exelon Way, Kennett Square, Pennsylvania 19348, and its telephone number is 610-765-6900.

Upon completion of Exelon's proposed merger with PSEG, the generation business of PSEG known as PSEG Power will be merged into Generation, which will be the surviving entity and PSEG Power will cease to exist. As of December 31, 2005, PSEG Power had total assets of $9 billion and $3 billion of outstanding debt which is currently anticipated to become part of Generation's consolidated debt. In addition, as part of the FERC approval of the Merger, Generation has proposed a market concentration mitigation plan involving the divestiture of 4,000 MW of coal, mid-merit and peaking generation in the PJM region and the ongoing auction of 2,600 MW of nuclear output, and the interim mitigation of fossil generation pending divestiture.

Federal and State Regulation

Exelon is subject to Federal and state regulation. ComEd is a public utility under the Illinois Public Utilities Act subject to regulation by the ICC. PECO is a public utility under the Pennsylvania Public Utility Code subject to regulation by the PAPUC. ComEd, PECO and Generation are electric utilities under the Federal Power Act subject to regulation by the FERC. Specific operations of Exelon are also subject to the jurisdiction of various other Federal, state, regional and local agencies, including the NRC.

Exelon was a registered holding company and subject to a number of restrictions under the Public Utility Holding Company Act of 1935 (PUHCA) until the repeal of PUHCA, effective on February 8, 2006, pursuant to the Energy Policy Act of 2005 (the Energy Policy Act). Those restrictions involved financings, investments and affiliate transactions. Exelon had an order under PUHCA authorizing financing transactions for Exelon within certain limits. With the repeal of PUHCA, the SEC's financing jurisdiction under PUHCA for ComEd's and PECO's short-term financings and Generation's financings reverted to FERC. Exelon's financings are not subject to FERC jurisdiction. For additional information concerning regulatory approvals required for financings, see Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources. Exelon also had an order under PUHCA authorizing development activities, the formation of new intermediate subsidiaries for internal corporate structuring, internal corporate reorganizations, and investments in certain non-United States (U.S.) energy-related subsidiaries. With the repeal of PUHCA, Exelon is no longer subject to these restrictions. PUHCA also limited the businesses in which Exelon could engage and the investments that Exelon could make, and required that Exelon's utility subsidiaries constituted a single system that could be operated in an efficient, coordinated manner. With the repeal of PUHCA these restrictions are no longer applicable to Exelon.

Under the Energy Policy Act, FERC obtained additional jurisdiction for merger review and for the review of affiliate transactions, intercompany financings and cash management arrangements, certain internal corporate reorganizations, and certain holding company acquisitions of public utility and holding company securities. To the extent that the SEC's jurisdiction under PUHCA preempted certain aspects of state regulation, the repeal of PUHCA enhanced the authority of states to regulate Exelon and its utility subsidiaries.

For additional information about Federal and state restrictions on Exelon and its subsidiaries, see Management's Discussion and Analysis of Financial Condition and Results of Operation.

ComEd and PECO

Exelon's regulated energy delivery operations consist of ComEd and PECO.

ComEd is engaged principally in the purchase, transmission, distribution and sale of electricity to a diverse base of residential, commercial, industrial and wholesale customers in northern Illinois. ComEd is subject to extensive regulation by the ICC as to rates and service, the issuance of securities, and certain other aspects of ComEd's operations. ComEd is also subject to regulation by the FERC as to transmission rates and certain other aspects of ComEd's business.

ComEd's retail service territory has an area of approximately 11,300 square miles and an estimated population of eight million. The service territory includes the City of Chicago, an area of about 225 square miles with an estimated population of three million. ComEd has approximately 3.7 million customers.

ComEd's franchises are sufficient to permit it to engage in the business it now conducts. ComEd's franchise rights are generally nonexclusive rights documented in agreements and, in some cases, certificates of public convenience issued by the ICC. With few exceptions, the franchise rights have stated expiration dates ranging from 2007 to 2061 and subsequent years. ComEd anticipates working with the appropriate agencies to extend or replace the franchise agreements prior to expiration.

PECO is engaged principally in the purchase, transmission, distribution and sale of electricity to residential, commercial and industrial customers in southeastern Pennsylvania and the purchase, distribution and sale of natural gas to residential, commercial and industrial customers in the Pennsylvania counties surrounding the City of Philadelphia. PECO is subject to extensive regulation by the PAPUC as to electric and gas rates and service, the issuances of certain securities and certain other aspects of PECO's operations. PECO is also subject to regulation by the FERC as to transmission rates and certain other aspects of PECO's business.

PECO's retail service territory has an area of approximately 2,100 square miles and an estimated population of 3.8 million. PECO provides electric delivery service in an area of approximately 2,000 square miles, with a population of approximately 3.7 million, including 1.5 million in the City of Philadelphia. Natural gas service is supplied in an area of approximately 1,900 square miles in southeastern Pennsylvania adjacent to the City of Philadelphia, with a population of approximately 2.3 million. PECO delivers electricity to approximately 1.5 million customers and natural gas to approximately 472,000 customers.

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

ComEd's and PECO's kilowatthour (kWh) sales and load of electricity are generally higher during the summer periods and winter periods, when temperature extremes create demand for either summer cooling or winter heating. ComEd's highest peak load occurred on August 21, 2003 and was 22,054 megawatts (MWs); its highest peak load during a winter season occurred on December 19, 2005 and was 16,081 MWs. PECO's highest peak load occurred on July 27, 2005 and was 8,626 MWs; its highest peak load during a winter season occurred on December 20, 2004 and was 6,838 MWs.

PECO's gas sales are generally higher during the winter periods when cold temperatures create demand for winter heating. PECO's highest daily gas send out occurred on January 17, 2000 and was 718 million cubic feet (mmcf).

Retail Electric Services

Electric utility restructuring legislation was adopted in Pennsylvania in December 1996 and in Illinois in December 1997. Both Illinois and Pennsylvania permit competition by alternative generation suppliers for the supply of retail electricity while transmission and distribution service remains regulated. The legislation and related regulatory orders in both states allow customers to choose an alternative electric generation supplier; required rate reductions and imposed freezes or caps on rates during a transition period following the adoption of the legislation; and allow the collection of competitive transition charges (CTCs) from customers to recover a portion of the costs that might not otherwise be recovered in a competitive market (stranded costs) during the transition period.

Under Illinois and Pennsylvania legislation, ComEd and PECO are required to provide generation services to customers, except for certain large customers of ComEd, who do not or cannot choose an alternative supplier. Provider of last resort (POLR) obligations refer to the obligation of a utility to provide bundled services to those customers who do not take service from an alternative retail electric supplier or who choose to return to the utility after taking service from an alternative supplier. Because the choice generally lies with the customer, POLR obligations make it difficult for the utility to predict and plan for the level of customers and associated electricity demanded.

ComEd. All of ComEd's customers are eligible to choose an alternative retail electric supplier and most non-residential customers can also elect the power purchase option (PPO) that allows the purchase of electricity from ComEd at market-based prices. As of December 31, 2005, one alternative electric supplier has approval from the ICC to serve residential customers in Illinois; however, no residential customers have actually selected an alternative electric supplier. At December 31, 2005, approximately 21,300 non-residential customers, representing approximately 33% of ComEd's annual retail kilowatthour sales, had elected to purchase their electricity from an alternative electric supplier or had chosen the PPO. Customers who receive electricity from an alternative electric supplier and customers who have elected the PPO continue to pay a delivery charge to ComEd, which generally includes a CTC. Assuming ComEd is able to fully collect its costs of delivering electric service, there should be minimal long-term impact of customer choice on its results of operations. On January 24, 2006, the ICC unanimously approved the reverse-auction process as described below under "Illinois Procurement Filing," with some modifications to enhance consumer protections and provide additional regulatory oversight. This approval, which is subject to rehearing and appeal, should provide ComEd with stability and greater certainty that it will be able to procure energy through the auction process and pass through the costs of that energy to ComEd's customers beginning in 2007 through a transparent market mechanism in the reverse-auction process. ComEd petitioned for rehearing of the ICC decision on certain issues, but that petition was denied by the ICC on February 8, 2006. ComEd has offered to ease the impact of the expected increase in rates on residential customers, some or all of which could require regulatory or legislative approval to implement. See risk factor "ComEd may be required to sell energy at capped rates while buying energy at market rates, which are more volatile and potentially higher" in ITEM 1A. Risk Factors of Exelon's 2005 Form 10-K for further details.

In addition to retail competition for generation services, the Illinois legislation provided for phased residential base rate reductions totaling 20%, a sharing with customers of any earnings over a defined threshold and a base rate freeze, reflecting the residential base rate reductions, through January 1, 2007. A utility may request a rate increase during the rate freeze period only when the return on equity falls beneath a defined floor to ensure the utility's financial viability. Under the Illinois legislation, if the two-year average of the earned return on common equity of a utility through December 31, 2006 exceeds an established threshold, one-half of the excess earnings must be refunded to customers. The threshold rate of return on common equity is based on a two-year average of the Monthly U.S. Treasury Long-Term Average Bond Rates (20 years and above) plus 8.5% in the years 2000 through 2006. Earnings for purposes of ComEd's threshold include ComEd's net income calculated in accordance with accounting principles generally accepted in the United States (GAAP) and reflect the amortization of regulatory assets. Under the Illinois statue, any impairment of goodwill has no impact on the determination of the cap on ComEd's allowed equity return during the transition period. As a result of the Illinois legislation, at December 31, 2005, ComEd had a regulatory asset related to recoverable transition costs with an unamortized balance of $43 million, which will be fully recovered and amortized during 2006. ComEd has not triggered the earnings sharing provision through 2005 and does not currently expect to trigger the earnings sharing provision in 2006.

ComEd expects its capital expenditures will exceed depreciation on its rate base assets through at least 2006. The base rate freeze, coupled with other provisions of the Illinois restructuring law, generally precludes rate recovery of and on such incremental investments prior to January 1, 2007. Unless ComEd can offset the additional carrying costs against cost reductions, its return on investment will be reduced during the remaining period of the rate freeze and until rate increases, post 2006, are approved authorizing a return of and on this new investment.

Illinois Procurement Filing. In 2004, the ICC initiated and conducted a workshop process to consider issues related to retail electric service in the post-transition period (i.e., post 2006). Issues addressed included utility wholesale electricity procurement methodology, rates, competition and utility service obligations and energy assistance programs. All interested parties were invited to participate. The end result was a report from the ICC to the Illinois General Assembly that was generally supportive of utilities competitively procuring electricity through a reverse-auction process with full recovery of the supply costs from retail customers. In the proposed reverse-auction model, qualified energy suppliers would compete in a transparent, fair and structured auction to provide electricity to the utilities and their customers; winning bidders would provide the electricity needed at the price determined by the auction's results; and the utilities would make no profit on the electricity but would recover from customers the price of procurement. The ICC staff would oversee the entire process.

On February 25, 2005, ComEd filed with the ICC seeking regulatory approval of tariffs that implement the methodologies supported by the report, including a proposal consistent with the reverse-auction process described above (the Procurement Case). As requested by ComEd, the ICC initiated hearings on the matter. The Illinois Attorney General, Citizens' Utility Board (CUB), Cook County State's Attorney's Office and the Environmental Law and Public Policy Center subsequently filed a motion to dismiss the proceeding arguing that customers whose retail service has not been declared competitive are entitled to cost-based rates for electricity and delivery and that the ICC lacked authority to approve rates based on the market value of electricity, as proposed by ComEd. On June 1, 2005, the administrative law judge denied the motion and, on July 13, 2005, the ICC denied the appeal. On December 5, 2005, the administrative law judge issued a proposed order that recommended that the ICC approve the competitive procurement process similar to the ComEd proposal. The administrative law judge reaffirmed an earlier ruling that the ICC has legal authority under the Public Utility Act to approve an auction process and the resulting rates. The proposed order also increased the regulatory oversight of the process.

On January 24, 2006, the ICC, by a unanimous vote, approved a reverse-auction competitive bidding process for procurement of power by ComEd for the time period after 2006. The procurement process is similar to the process described in the Procurement Case and the administrative law judge's order described above, with some modifications to enhance consumer protection. The auction will be administered by an independent auction manager, with oversight by the ICC staff. The first auction is scheduled to take place during the fall of 2006, at which time ComEd's entire load will be up for bid. To mitigate the effects of changes in future prices, the load will be staggered in three-year contracts. To further mitigate the impact on its residential customers of transitioning to this process, ComEd has offered to develop a "cap and deferral" proposal to ease the impact of the expected increase in rates on residential customers, some or all of which could require regulatory or legislative approval to implement. A cap and deferral proposal, generally speaking, would limit the procurement costs that ComEd could pass through to its customers for a specified period of time and allow ComEd to collect any unrecovered procurement costs in later years.

Several parties that were opposed to the Procurement Case have indicated that they will petition the ICC for rehearing and will challenge the ICC decision in court. ComEd also petitioned for rehearing of the ICC decision on certain issues, but that petition was denied by the ICC on February 8, 2006. It is also possible that interested parties could introduce legislation in Illinois in an attempt to modify the procurement process or the rates that ComEd may charge consumers for the power ComEd purchases to meet the needs of consumers. The Illinois General Assembly has held hearings concerning generation procurement after 2006, and it may take action on this issue.

On September 1, 2005, the Illinois Attorney General, the Cook County State's Attorney, CUB and the Environmental Law and Public Policy Center filed a two-count complaint in the Chancery Division of the Circuit Court of Cook County against the ICC and the individual ICC commissioners (the Procurement Litigation). The Procurement Litigation sought to block the ICC from approving the Procurement Case on the theory that the ICC lacked the authority to approve the rates because not all of the services that will be provided under the Procurement Case have been declared competitive and do not qualify for market-based rates. The legal argument underlying the Procurement Litigation is substantially similar to the legal argument that was presented to the administrative law judge, and to the ICC on appeal, and rejected by both, in the third quarter of 2005. ComEd intervened in the Procurement Litigation to deny the allegations in the complaint and sought a determination that the ICC has appropriate legal authority to approve the proposed electricity procurement process pending before the ICC in the Procurement Case. ComEd moved for summary judgment in the litigation, and the ICC moved to dismiss one claim in the litigation and for summary judgment on the other claim. A hearing on the motions was held on December 14, 2005 and the court issued a written order on January 20, 2006 denying the relief sought by the plaintiffs and dismissing the case with prejudice.

On October 17, 2005, ComEd and Generation filed an application with the FERC seeking approval that the proposed Illinois auction process meets FERC principles and that if Generation is selected as a winning bidder in the Illinois auction, the standard agreements under which Generation would sell energy, capacity and ancillary services to ComEd would be acceptable to the FERC. On December 16, 2005, the FERC issued an order granting both requests.

In November 2005, ComEd announced several actions intended to affirm the fact that ComEd is an independent entity, separate and distinct from its parent Exelon, and to strengthen ComEd's ability to successfully manage some potentially challenging financial and strategic issues as Illinois continues its transition to restructuring after 2006. The actions include the election of a new board of directors of ComEd and selection of senior officers. The senior officers have responsibilities solely for ComEd.

The ICC, in its Order approving the Procurement Case, also ordered its Staff to "present orders initiating three separate rulemakings regarding demand response programs, energy efficiency programs and renewable energy resources to the Commission within thirty (30) days of the entry of this Order." ComEd intends to participate in any such rulemakings.

Illinois Rate Case. On August 31, 2005, ComEd filed a rate case with the ICC, which seeks, among other things, to allocate the costs of delivering electricity and to adjust ComEd's rates for delivering electricity effective January 2, 2007 (Rate Case). Several intervenors in the Rate Case, including the ICC staff and the Illinois Attorney General, have suggested, and provided testimony, that ComEd's rates should actually be reduced. The commodity component of ComEd's rates will be established by the reverse-auction process in accordance with the ICC order in the Procurement Case, assuming the ICC order on this matter is upheld upon appeal. The results of the Rate Case are not expected to be known until at least the third quarter of 2006.

ComEd cannot predict the results of the Rate Case before the ICC or whether the Illinois General Assembly might take action that could have a material impact on the outcome of the regulatory process. However, if the price at which ComEd is allowed to sell electricity beginning in 2007 is below

ComEd's cost to procure and deliver electricity, there may be material adverse consequences to ComEd and, possibly, Exelon. Exelon and ComEd believe that these potential material adverse consequences could include, but may not be limited to, loss of ComEd's investment grade credit rating and a possible reduction in Exelon's credit ratings, limited or lost access for ComEd to credit markets to finance operations and capital investment, and loss of ComEd's capacity to enter into bilateral long-term electricity procurement contracts, which would likely force ComEd to procure electricity at more volatile and potentially higher prices in the spot market. Moreover, to the extent ComEd is not permitted to recover its costs, ComEd's ability to maintain and improve service may be diminished and its ability to maintain reliability may be impaired. In the nearer term, these prospects could have adverse effects on ComEd's liquidity if vendors reduce credit or shorten payment terms or if ComEd's financing alternatives become more limited and significantly less flexible. ComEd also cannot predict the long-term impact of customer choice for electricity supply on its results of operations.

The Illinois restructuring legislation also provided for the collection of a CTC from customers who choose to purchase electricity from an alternative electric supplier or elect the PPO during the transition period which extends through 2006. The CTC is applied on a cents per kWh basis and considers the revenue that would have been collected from a customer under tariffed rates as reduced by the revenue the utility will receive for providing delivery services to the customer, the market price for electricity and a defined mitigation factor, which represents the utility's opportunity to develop new revenue sources and achieve cost reductions. The CTC allows ComEd to recover some of its costs that might otherwise be unrecoverable under market-based rates.

ComEd's market value energy credit is used to determine the price for specified market-based rate offerings and the amount of the CTC that ComEd is allowed to collect from customers who select an alternative electric supplier or the PPO. The credit has the effect of reducing ComEd's CTCs to customers. The current annual market price adjustment reflects forward, rather than historical, market prices for electricity and allows customers to lock in current levels of CTCs for the remainder of the regulatory transition period ending in 2006.

In 2005 and 2004, ComEd collected $105 million and $169 million in CTC revenues, respectively. ComEd estimates that CTC revenue will range from $35 million to $50 million in 2006.

The Illinois restructuring legislation provides that an electric utility, such as ComEd, will be liable for actual damages suffered by customers in the event of a continuous electricity outage of four hours or more affecting 30,000 or more customers and provides for reimbursement of governmental emergency and contingency expenses incurred in connection with any such outage. The legislation bars recovery of consequential damages. The legislation also allows an affected utility to seek relief from these provisions from the ICC when the utility can show that the cause of the outage was unpreventable due to weather events or conditions, customer tampering or third-party causes. During the years 2005, 2004 and 2003, ComEd did not have any outages that triggered the reimbursement requirement.

ComEd has a purchase power agreement (PPA) with Generation under which ComEd obtains substantially all of its electric supply from Generation through 2006. Prices for this electricity vary depending on the time of day and month of delivery.

PECO. Under the Pennsylvania Electricity Generation Customer Choice and Competition Act (Competition Act), all of PECO's retail electric customers have the right to choose their generation suppliers. At December 31, 2005, approximately 1% of PECO's residential load, 13% of its small commercial and industrial load and 1% of its large commercial and industrial load were purchasing generation service from alternative generation suppliers. Customers who purchase electricity from an alternative electric supplier continue to pay a delivery charge to PECO.

In addition to retail competition for generation services, PECO's 1998 settlement of its restructuring case mandated by the Competition Act established caps on generation and distribution rates. The 1998 settlement also authorized PECO to recover $5.3 billion of stranded costs and to securitize up to $4.0 billion of its stranded cost recovery, which was subsequently increased to $5.0 billion.

Under the 1998 settlement, PECO's distribution and transmission rates were capped through June 30, 2005 at the level in effect on December 31, 1996. Generation rates, consisting of the charge for stranded cost recovery and a shopping credit or capacity and energy charge, were capped through December 31, 2010. For 2005, the generation rate cap was $0.0698 per kWh, increasing to $0.0751 per kWh in 2006 and $0.0801 per kWh in 2007. The rate caps are subject to limited exceptions, including significant increases in Federal or state taxes or other significant changes in law or regulations that would not allow PECO to earn a fair rate of return. Under the settlement agreement entered into by PECO in 2000 relating to the PAPUC's approval of the merger among PECO, Unicom Corporation (Unicom), the former parent company of ComEd, and Exelon (PECO / Unicom Merger), PECO agreed to $200 million in aggregate rate reductions for all customers over the period January 1, 2002 through December 31, 2005 and extended the rate cap on distribution and transmission rates through December 31, 2006.

Partial Settlement before the PAPUC. On January 27, 2006, the PAPUC approved the Merger and a partial settlement regarding PECO's distribution and transmission rates through 2010 and other financial commitments of PECO related to the Merger. The settlement reflected the conclusion of a process involving the majority of PECO customer groups during which PECO's cost data, return on equity and estimated Merger synergies were reviewed. The provisions of the PAPUC order and partial settlement are contingent upon the completion of the Merger. The PAPUC order and partial settlement require PECO to implement rate reductions aggregating $120 million during a four-year period and to cap its rates through the end of 2010. During the rate cap period, the PAPUC retains the right to lower PECO's rates if they are found to be excessive, and PECO retains the right to seek rate increases if certain events (such as significant increases in Federal or state income taxes or other significant changes in law or regulation that do not allow PECO to earn a fair rate of return) occur. The partial settlement also provides substantial funding for alternative energy and environmental projects, economic development, and expanded outreach and assistance for low-income customers. PECO also made commitments for enhanced customer service and reliability, commitments for charitable giving and employment, and a pledge to maintain its Philadelphia headquarters for a period of time. The total of these funding commitments is approximately $44 million, of which $30 million will be expensed at the time the Merger is completed. By separate motion, the PAPUC also indicated its intent to initiate a separate investigation, to which PECO had agreed in the partial settlement, to examine issues related to a potential combination of Philadelphia Gas Works, which provides gas distribution service in the City of Philadelphia, into Exelon's gas distribution businesses. This investigation will commence no earlier than 30 days after the close of the Merger. The outcome of this potential examination is uncertain. However, Exelon does not believe that the PAPUC has the authority to compel such a transaction if the two parties do not agree to terms through arms length negotiations. See General—Proposed Merger with Public Service Enterprise Group Incorporated above and Note 4 of Exelon's Notes to Consolidated Financial Statements for further discussion.

As a mechanism for utilities to recover their allowed stranded costs, the Competition Act provides for the imposition and collection of non-bypassable transition charges on customers' bills. Transition charges are assessed to and collected from all retail customers who have been assigned stranded cost responsibility and access the utility's transmission and distribution systems. As the transition charges are based on access to the utility's transmission and distribution system, they are assessed regardless of whether the customer purchases electricity from the utility or an alternative electric supplier. The Competition Act provides, however, that the utility's right to collect transition charges is contingent on the continued operation, at reasonable availability levels, of the assets for which the stranded costs were awarded, except where continued operation is no longer cost efficient because of the transition to a competitive market.

As mentioned above, PECO has been authorized by the PAPUC to recover stranded costs of $5.3 billion over a twelve-year period ending December 31, 2010, with a return on the unamortized balance of 10.75%. At December 31, 2005, the unamortized balance of PECO's stranded costs, or CTC regulatory asset, was $3.5 billion. The following table shows PECO's allowed recovery of stranded costs, and amortization of the associated regulatory asset, for the years 2006 through 2010 as authorized by the PAPUC based on the level of transition charges established in the settlement of PECO's restructuring case and the projected annual retail sales in PECO's service territory. Recovery of transition charges for stranded costs and PECO's allowed return on its recovery of stranded costs are included in revenues. To the extent the actual recoveries of transition charges in any one year differ from the authorized amount set forth below, an annual reconciliation adjustment to the transition charges rate is made to increase or decrease the subsequent year's collections accordingly, except during 2010, in which the reconciling adjustments are made quarterly or monthly as needed.

Year (in millions)	Estimated CTC Revenue	Estimated Stranded Cost Amortization
2006	$903	$550
2007	910	619
2008	917	697
2009	924	783
2010	932	880

Under the Competition Act, licensed entities, including alternative electric suppliers, may act as agents to provide a single bill and provide associated billing and collection services to retail customers located in PECO's retail electric service territory. In that event, the alternative supplier or other third party replaces the customer as the obligor with respect to the customer's bill and PECO generally has no right to collect such receivable from the customer. Third-party billing would change PECO's customer profile (and risk of non-payment by customers) by replacing multiple customers with the entity providing third-party billing for those customers. PAPUC-licensed entities may also finance, install, own, maintain, calibrate and remotely read advanced meters for service to retail customers in PECO's retail electric service territory. To date, no third parties are providing billing of PECO's charges to customers or advanced metering. Only PECO can physically disconnect or reconnect a customer's distribution service.

PECO has a PPA with Generation under which PECO obtains substantially all of its electric supply from Generation through 2010. The price for this electricity is essentially equal to the energy revenues earned from customers as specified by PECO's 1998 settlement of its restructuring case mandated by the Competition Act. Subsequent to 2010, PECO expects to procure all of its supply from market sources, which could include Generation.

Regulations applicable to all Pennsylvania electric utilities' POLR obligations are being developed by the PAPUC. PECO will continue to monitor the developments of these regulations.

In November 2004, Pennsylvania adopted Act 213, the Alternative Energy Portfolio Standards Act of 2004. For more information, see ITEM 1. Business—Environmental Regulation—Renewable and Alternative Energy Portfolio Standards of Exelon's 2005 Form 10-K.

Transmission Services

ComEd and PECO provide wholesale and unbundled retail transmission service under rates established by the FERC. The FERC has used its regulation of transmission to encourage competition for wholesale generation services and the development of regional structures to facilitate regional wholesale markets. Under the FERC's open transmission access policy promulgated in Order No. 888, ComEd and PECO, as owners of transmission facilities, are required to provide open access to their transmission facilities under filed tariffs at cost-based rates. Under the FERC's Order No. 889, ComEd and PECO are required to comply with the FERC's Standards of Conduct regulation, as amended, governing the communication of non-public information between the transmission owner's transmission employees and wholesale merchant employees or the employees of any energy affiliate of the transmission owner. The FERC's amendments to the Standards of Conduct regulation under Order No. 2004 do not detrimentally affect Exelon's business.

PJM Interconnection, LLC (PJM) is the independent system operator and the FERC-approved regional transmission organization (RTO) for the Mid-Atlantic and Midwest regions in which it operates. PJM is the transmission provider under, and the administrator of, the PJM Open Access Transmission Tariff (PJM Tariff), operates the PJM Interchange Energy Market and Capacity Credit Markets, and controls through central dispatch the day-to-day operations of the bulk power system of the PJM region. ComEd and PECO are members of PJM and provide regional transmission service pursuant to the PJM tariff. ComEd, PECO and the other transmission owners in PJM have turned over control of their transmission facilities to PJM and their transmission systems are currently under the dispatch control of PJM. Under the PJM Tariff, transmission service is provided on a region-wide, open-access basis using the transmission facilities of the PJM members at rates based on the costs of transmission service.

The FERC has attempted to expand the development of regional markets, which has generated substantial opposition from some state regulators and other governmental bodies. In addition, efforts to develop an RTO have been abandoned in certain regions. Notwithstanding these difficulties, the Midwest Independent System Operator, Inc. (MISO), has been certified as an RTO by FERC. MISO is attempting to develop central generation dispatch and transmission operations across the Midwestern United States, contiguous to PJM's footprint. The FERC has ordered the elimination of rate barriers and protocol differences between MISO and PJM. Exelon supports the development of RTOs and implementation of standard market protocols.

In November 2004, the FERC issued two orders authorizing ComEd and PECO to recover amounts as a result of the elimination of through and out (T&O) rates for transmission service scheduled out of or across their respective transmission systems and ending within pre-expansion PJM or MISO territories. T&O rates were terminated pursuant to FERC orders effective December 1, 2004. The new rates, known as Seams Elimination Charge/Cost Adjustment/Assignment (SECA), are collected from load-serving entities within PJM and MISO over a transitional period from December 1, 2004 through March 31, 2006, subject to refund, surcharge and hearing. As load-serving entities, ComEd and PECO are also required to pay SECA rates based on the benefits they receive from the elimination of T&O rates of other transmission owners within PJM and MISO. On June 16, 2005, FERC issued an order setting a hearing to address SECA cost recovery issues, and consolidated that proceeding with a proceeding to address long-term transmission rate design.

Amounts collected under the SECA rates are subject to refund and surcharge and the ultimate outcome of the proceeding establishing SECA rates is uncertain.

Gas

PECO's gas sales and gas transportation revenues are derived pursuant to rates regulated by the PAPUC. PECO's purchased gas cost rates, which represent a portion of total rates, are subject to quarterly adjustments designed to recover or refund the difference between the actual cost of purchased gas and the amount included in rates.

PECO's gas customers have the right to choose their gas suppliers or to purchase their gas supply from PECO at cost. Approximately 32% of PECO's current total yearly throughput is provided by gas suppliers other than PECO and is related primarily to the supply of PECO's large commercial and industrial customers. Gas transportation service provided to customers by PECO remains subject to rate regulation. PECO also provides billing, metering, installation, maintenance and emergency response services.

PECO's natural gas supply is provided by purchases from a number of suppliers for terms of up to eight years. These purchases are delivered under several long-term firm transportation contracts. PECO's aggregate annual firm supply under these firm transportation contracts is 44.6 million dekatherms. Peak gas is provided by PECO's liquefied natural gas (LNG) facility and propane-air plant. PECO also has under contract 22.0 million dekatherms of underground storage through service agreements. Natural gas from underground storage represents approximately 33% of PECO's 2005-2006 heating season planned supplies.

Construction Budget

ComEd's and PECO's businesses are capital intensive and require significant investments in energy transmission and distribution facilities, and in other internal infrastructure projects. The following table shows the most recent estimate of capital expenditures for plant additions and improvements for ComEd and PECO for 2006:

(in millions)	ComEd	PECO
Transmission and distribution	$870	$215
Gas	—	65
Other	55	50
Total	$925	$330

Approximately 50% of the projected 2006 capital expenditures at ComEd and PECO are for continuing efforts to maintain and improve the reliability of their transmission and distribution systems. The remainder of the capital expenditures support customer and load growth.

Generation

Generation is one of the largest competitive electric generation companies in the United States, as measured by owned and controlled MWs. Generation combines its large generation fleet with an experienced wholesale power marketing operation and the competitive retail sales business of Exelon Energy, which became part of Generation effective as of January 1, 2004.

At December 31, 2005, Generation owned generation assets with a net capacity of 25,099 MWs, including 16,856 MWs of nuclear capacity. In addition, Generation controlled another 8,191 MWs of capacity through long-term contracts.

Generation's wholesale marketing unit, Power Team, a major wholesale marketer of energy, uses Generation's energy generation portfolio, transmission rights and expertise to ensure delivery of energy to Generation's wholesale customers under long-term and short-term contracts, including the load requirements of ComEd and PECO. In addition, Power Team markets energy in the wholesale bilateral and spot markets.

Exelon Energy provides retail electric and gas services as an unregulated retail energy supplier in Illinois, Michigan and Ohio. Exelon Energy's business is dependent upon continued deregulation of retail electric and gas markets and its ability to obtain supplies of electricity and gas at competitive prices in the wholesale market. The low-margin nature of the business makes it important to service customers with higher volumes so as to manage costs.

Generating Resources

At December 31, 2005, the generating resources of Generation consisted of the following:

Type of Capacity	MWs
Owned generation assets [a]	
Nuclear	16,856
Fossil [b, c]	6,636
Hydroelectric	1,607
Owned generation assets	25,099
Long-term contracts [d]	8,191
TEG and TEP [e]	230
Total generating resources	33,520

(a) See General Description of Our Business—Generation "Fuel" for sources of fuels used in electric generation.
(b) Includes the total capacity of the Southeast Chicago Energy Project.
(c) Excludes 195 MWs related to the capacity of Handley Units 1 and 2 and Mountain Creek Unit 3. These units were removed from service in 2005.
(d) Contracts ranging in duration of up to 25 years.
(e) Generation, through its investments in Termoeléctrica del Golfo (TEG) and Termoeléctrica Peñoles (TEP), owns a 49.5% interest in two facilities in Mexico, each with a capacity of 230 MWs.

The owned generating resources of Generation are located in the Midwest region (approximately 45% of capacity), the Mid-Atlantic region (approximately 44% of capacity), the Southern region (approximately 9%), and the Northeast region (approximately 2% of capacity). The 8,191 MWs of capacity that Generation controls through long-term contracts are in the Midwest, Southeast and South Central regions.

On January 31, 2005, subsidiaries of Generation completed a series of transactions that resulted in Generation's sale of its investment in Sithe Energies, Inc. (Sithe). Specifically, subsidiaries of Generation closed on the acquisition of Reservoir Capital Group's 50% interest in Sithe and the sale of 100% of Sithe to Dynegy, Inc. (Dynegy). Prior to closing on the sale to Dynegy, subsidiaries of Generation received approximately $65 million in cash distributions from Sithe. As a result of the sale, Exelon and Generation deconsolidated approximately $820 million of debt from their balance sheets and were released from approximately $125 million of credit support. See Note 3 of Exelon's Notes to Consolidated Financial Statements for further information regarding the sale of Sithe.

The sale of Sithe did not include Tamuin International Inc. (formerly Sithe International, Inc.), which was sold to a subsidiary of Generation on October 13, 2004. Tamuin International, Inc., through its subsidiaries, has a 49.5% interest in two Mexican business trusts that own the TEG and TEP power stations, two 230 MW petcoke-fired generating facilities in Tamuín, Mexico.

Nuclear Facilities

Generation has ownership interests in eleven nuclear generating stations currently in service, consisting of 19 units with 16,856 MWs of capacity. For additional information, see ITEM 2. Properties of Exelon's 2005 Form 10-K. Generation's nuclear generating stations are operated by Generation, with the exception of the two units at the Salem Generating Station (Salem), which are operated by PSEG Nuclear, LLC (PSEG Nuclear), an indirect, wholly owned subsidiary of PSEG. AmerGen, wholly owned by Generation, operates the Clinton Nuclear Power Station, the Three Mile Island (TMI) Unit No. 1 and the Oyster Creek Generating Station (Oyster Creek).

Effective January 17, 2005, Generation began overseeing daily plant operations at Salem and Hope Creek nuclear generating stations through an Operating Services Contract (OSC) with PSEG Nuclear. Hope Creek is a nuclear generating station wholly owned by PSEG Nuclear. Under the OSC, PSEG Nuclear remains as the license holder with exclusive legal authority to operate and maintain the plants, retains responsibility for management oversight and has full authority with respect to the marketing of its share of the output from the facilities.

In 2005, 71% of Generation's electric supply was generated from the nuclear generating facilities. During 2005 and 2004, the nuclear generating facilities operated by Generation achieved a 93.5% capacity factor.

During 2004, both Quad Cities' units operated only intermittently at Extended Power Uprate (EPU) generation levels due to performance issues with their steam dryers. As of the third quarter of 2005, both of the Quad Cities' units returned to EPU generation levels after extensive testing and load verification on new replacement steam dryers was completed.

Near the end of 2005, the generation levels of both Quad Cities' units were again reduced to pre-EPU generation levels to address vibration–related equipment issues not directly related to the steam dryers. The units will be brought back to full EPU generation levels after all issues are addressed to ensure safe and reliable operations at the EPU output levels which is expected to occur in 2006.

In 2004, Generation joined a consortium of eleven companies, NuStart Energy Development, LLC (NuStart), which was formed for the purpose of seeking a license to build a new nuclear facility under the NRC's new permitting process. As of December 31, 2005, Generation's investment in NuStart was $2 million.

Regulation of Nuclear Power Generation. Generation is subject to the jurisdiction of the NRC with respect to the operation of its nuclear generating stations, including the licensing of operation of each station. The NRC subjects nuclear generating stations to continuing review and regulation covering, among other things, operations, maintenance, emergency planning, security and environmental and radiological aspects of those stations. The NRC may modify, suspend or revoke operating licenses and impose civil penalties for failure to comply with the Atomic Energy Act, the regulations under such Act or the terms of such licenses. Changes in regulations by the NRC may require a substantial increase in capital expenditures for nuclear generating facilities and/or increased operating costs of nuclear generating units.

NRC reactor oversight results, as of December 31, 2005, indicate that the performance indicators for the nuclear plants operated by Generation are all in the highest performance band.

Licenses. Generation has 40-year operating licenses from the NRC for each of its nuclear units and has received 20-year operating license renewals for Peach Bottom Units 2 and 3, Dresden Units 2 and 3, and Quad Cities Units 1 and 2. In December 2004, the NRC issued an order that will permit Oyster Creek to operate beyond its license expiration in April 2009 if the NRC has not completed reviewing the application for renewal. The application for Oyster Creek's license renewal was filed July 22, 2005, in compliance with this order. Generation is currently evaluating its other nuclear units for possible license renewal. The operating license renewal process takes approximately four to five years from the commencement of the project until completion of the NRC's review. The NRC review process takes approximately two years from the docketing of an application. Each requested license renewal is expected to be for 20 years beyond the current license expiration. Depreciation provisions are based on the estimated useful lives of the stations, which assume the renewal of the operating licenses for all of Generation's operating nuclear generating stations. In the first quarter of 2005, Generation applied the same depreciation estimated useful life assumption to its ownership share in the Salem Generating Station.

The following table summarizes the current operating license expiration dates for Generation's nuclear facilities in service:

Station	Unit	In-Service Date [a]	Current License Expiration
Braidwood	1	1988	2026
	2	1988	2027
Byron	1	1985	2024
	2	1987	2026
Clinton	1	1987	2026
Dresden	2	1970	2029
	3	1971	2031
LaSalle	1	1984	2022
	2	1984	2023
Limerick	1	1986	2024
	2	1990	2029
Oyster Creek	1	1969	2009
Peach Bottom	2	1974	2033
	3	1974	2034
Quad Cities	1	1973	2032
	2	1973	2032
Salem	1	1977	2016
	2	1981	2020
Three Mile Island	1	1974	2014

(a) Denotes year in which nuclear unit began commercial operations.

Nuclear Waste Disposal. There are no facilities for the reprocessing or permanent disposal of spent nuclear fuel (SNF) currently in operation in the United States, nor has the NRC licensed any such facilities. Generation currently stores all SNF generated by nuclear generating facilities in on-site storage pools and, in the case of Peach Bottom, Oyster Creek, Dresden and Quad Cities, some SNF has been placed in dry cask storage facilities. Not all of Generation's SNF storage pools have sufficient storage capacity for the life of the respective plant. Generation is developing dry cask storage facilities, as necessary, to support operations.

As of December 31, 2005, Generation had approximately 44,792 SNF assemblies (10,402 tons) stored on site in SNF pools or dry cask storage. On-site dry cask storage in concert with on-site storage pools will be capable of meeting all current and future SNF storage requirements at Generation's sites. The following table describes the current status of Generation's SNF storage facilities.

Site	Date for loss of full core reserve [a]
Dresden	Dry cask storage in operation
Quad Cities	Dry cask storage in operation
Byron	2011
LaSalle	2012
Braidwood	2013
Clinton [b]	2006
Peach Bottom	Dry cask storage in operation
Limerick	2009
Oyster Creek	Dry cask storage in operation
Three Mile Island	Life of plant storage capable in SNF pool
Salem	2011

(a) The date for loss of full core reserve identifies when the on-site storage pool will no longer have sufficient space to discharge a full complement of fuel from the reactor core.

(b) A modification to the on-site storage pool is in progress to increase the amount of SNF that can be stored in the pool. This will move the date for loss of full core reserve at Clinton out to approximately 2012.

Under the Nuclear Waste Policy Act of 1982 (NWPA), the U.S. Department of Energy (DOE) is responsible for the development of a repository for and the disposal of SNF and high-level radioactive waste. As required by the NWPA, Generation is a party to contracts with the DOE (Standard Contracts) to provide for disposal of SNF from its nuclear generating stations. In accordance with the NWPA and the Standard Contracts, Generation pays the DOE one mill ($.001) per kWh of net nuclear generation for the cost of SNF disposal. This fee may be adjusted prospectively in order to ensure full cost recovery. The NWPA and the Standard Contracts required the DOE to begin taking possession of SNF generated by nuclear generating units by no later than January 31, 1998. The DOE, however, failed to meet that deadline and its performance will be delayed significantly. The DOE's current estimate for opening a SNF permanent disposal facility is 2012. This extended delay in SNF acceptance by the DOE has led to Generation's adoption of dry cask storage at its Dresden, Quad Cities, Peach Bottom and Oyster Creek Stations and its consideration of dry cask storage at other stations. See Note 13 of Exelon's Notes to Consolidated Financial Statements for additional information regarding spent fuel storage claims and issues.

During 2004, Exelon and the U.S. Department of Justice, in close consultation with the DOE, reached a settlement of a suit originally commenced by ComEd in 1998. Under the settlement, the government has agreed to reimburse Exelon for costs associated with storage of spent fuel at Generation's nuclear stations pending DOE's fulfilment of its obligations to take possession of SNF. Under the settlement agreement, Generation received $80 million in gross reimbursements for storage costs already incurred ($53 million net, after considering amounts due from Exelon to co-owners of certain nuclear stations). In 2005, Generation received $58 million in gross reimbursements for storage costs incurred between October 1, 2003 and June 30, 2005, ($35 million net, after considering amounts due from Exelon to co-owners and previous owners of certain nuclear stations). Generation plans to submit annual reimbursement requests for costs associated with the storage of spent nuclear fuel. In all cases, reimbursement requests will be made only after costs are incurred and only for costs resulting from DOE delays in accepting the SNF.

The Standard Contracts with the DOE also required the payment to the DOE of a one-time fee applicable to nuclear generation through April 6, 1983. The fee related to the former PECO units has been paid. Pursuant to the Standard Contracts, ComEd previously elected to pay the one-time fee of $277 million for its units (which are now part of Generation), with interest to the date of payment, just prior to the first delivery of SNF to the DOE. As of December 31, 2005, the unfunded liability for the one-time fee with interest (which has been assumed by Generation) was $906 million. Interest accrues at the 13-week Treasury Rate. The 13-week Treasury Rate in effect, for calculation of the interest accrual at December 31, 2005, was 3.983%. The outstanding one-time fee obligation for the Oyster Creek and TMI units remains with the former owners. The Clinton Unit has no outstanding obligation.

As a by-product of their operations, nuclear generating units produce low-level radioactive waste (LLRW). LLRW is accumulated at each generating station and permanently disposed of at Federally licensed disposal facilities. The Federal Low-Level Radioactive Waste Policy Act of 1980 provides that states may enter into agreements to provide regional disposal facilities for LLRW and restrict use of those facilities to waste generated within the region. Illinois and Kentucky have entered into an agreement, although neither state currently has an operational site and none is currently expected to be operational until after 2011. Pennsylvania, which had agreed to be the host site for LLRW disposal facilities for generators located in Pennsylvania, Delaware, Maryland and West Virginia, has suspended the search for a permanent disposal site.

Generation has temporary on-site storage capacity at its nuclear generation stations for limited amounts of LLRW and has been shipping its LLRW to disposal facilities in South Carolina and Utah. With a limited number of available LLRW disposal facilities, Generation anticipates the possibility of continuing difficulties in disposing of LLRW. Generation continues to pursue alternative disposal strategies for LLRW, including a LLRW reduction program to minimize cost impacts.

The National Energy Policy Act of 1992 requires that the owners of nuclear reactors pay for the decommissioning and decontamination of the DOE uranium enrichment facilities. The total cost to all domestic utilities covered by this requirement was originally $150 million per year through 2006, of which Generation's share was approximately $20 million per year. Payments are adjusted annually to reflect inflation. Including the effect of inflation, Generation paid $31 million in 2005 ($27 million net after considering amounts collected from co-owners of certain nuclear stations).

Nuclear Insurance. The Price-Anderson Act limits the liability of nuclear reactor owners for claims that could arise from a single incident. The Price-Anderson Act was extended to December 31, 2025 under the terms of the Energy Policy Act. As of December 31, 2005, the current limit was $10.76 billion and is subject to change to account for the effects of inflation and changes in the number of licensed reactors. As required by the Price-Anderson Act, Generation carries the maximum available amount of nuclear liability insurance (currently $300 million for each operating site) and the remaining $10.46 billion is provided through mandatory participation in a financial protection pool. Under the Price-Anderson Act, all nuclear reactor licensees can be assessed a maximum charge per reactor per incident. The maximum assessment for all nuclear operators per reactor per incident (including a 5% surcharge) is $100.6 million, payable at no more than $15 million per reactor per incident per year. This assessment is subject to inflation and state premium taxes. In addition, the U.S. Congress could impose revenue-raising measures on the nuclear industry to pay claims.

See "Nuclear Insurance" within Note 20 of Exelon's Notes to Consolidated Financial Statements for a description of nuclear-related insurance coverage.

For information regarding property insurance, see ITEM 2. Properties—Generation of Exelon's 2005 Form 10-K. Generation is self-insured to the extent that any losses may exceed the amount of insurance maintained or are within the policy deductible for its insured losses. Such losses could have a material adverse effect on Generation's financial condition and results of operations.

Decommissioning. NRC regulations require that licensees of nuclear generating facilities demonstrate reasonable assurance that funds will be available in certain minimum amounts at the end of the life of the facility to decommission the facility. As more fully described below, both ComEd and PECO are currently collecting amounts from customers, which are ultimately remitted to the trust funds maintained by Generation that will be used to decommission nuclear facilities. The AmerGen facilities are not covered by ComEd, PECO or any other rate recovery of decommissioning funding from customers. Decommissioning expenditures are expected to occur primarily after the plants are retired. Based on current operating licenses and anticipated license renewals, decommissioning expenditures for plants in operation are currently estimated to begin in 2029.

Under the ICC order, ComEd is permitted to recover up to $73 million per year through 2006 from customers to decommission former ComEd nuclear plants. Collections are limited based on the ratio of electricity purchased by ComEd to the total amount generated from those units. In 2005, decommissioning revenues collected from ComEd customers totaled approximately $68 million and are expected to be approximately the same in 2006. Under the current ICC order, ComEd is not permitted to collect amounts for decommissioning subsequent to 2006. Nuclear decommissioning costs associated with the nuclear generating stations formerly owned by PECO continue to be recovered currently through rates charged by PECO to customers. Amounts recovered, currently $33 million per year, are remitted to Generation as allowed by the PAPUC. The PAPUC will allow PECO to collect from customers and remit to Generation, annually, through the operating life of the plants.

In 2003, the General Accounting Office (GAO) published a study on the NRC's need for more effective analyses to ensure the adequate accumulation of funds to decommission nuclear power plants in the United States. See the risk factor "Generation's financial performance may be negatively affected by liabilities arising from its ownership and operation of nuclear facilities" for further detail. Generation has reviewed the GAO's report and believes that, in reaching its conclusions, the GAO did not consider all aspects of Generation's decommissioning strategy, such as fund growth during the decommissioning period. The inclusion of estimated earnings growth on Generation's nuclear trust funds during the decommissioning period virtually eliminates any funding shortfalls identified in the GAO report.

Generation believes that the amounts currently being collected from ComEd and PECO, coupled with Generation's nuclear decommissioning trust funds and the expected investment earnings thereon will be sufficient to fully fund Generation's decommissioning obligations. AmerGen maintains decommissioning trust funds for each of its plants in accordance with NRC regulations. Generation believes that amounts in these trust funds together with expected investment earnings thereon will be sufficient to fully fund AmerGen's decommissioning obligations.

See Critical Accounting Policies and Estimates within Management's Discussion and Analysis of Financial Condition and Results of Operation for a further discussion of nuclear decommissioning.

Zion, a two-unit nuclear generation station, Peach Bottom Unit 1 and Dresden Unit 1 have permanently ceased power generation. SNF at Zion and Dresden Unit 1 is currently being stored in on-site storage pools and dry cask storage, respectively, until a permanent repository under the NWPA is completed. All of Peach Bottom Unit 1's SNF has been moved off site. Generation has recorded a liability totaling $766 million at December 31, 2005, which represents the estimated cost of decommissioning Zion, Peach Bottom Unit 1 and Dresden Unit 1 in current year dollars. Certain decommissioning costs are currently being incurred; however, the majority of decommissioning expenditures are expected to occur primarily after 2013, 2033 and 2031 for Zion, Peach Bottom Unit 1 and Dresden Unit 1, respectively.

Fossil and Hydroelectric Facilities

Generation operates various fossil and hydroelectric facilities and maintains ownership interest in several other facilities such as LaPorte, Keystone, Conemaugh and Wyman, which are operated by third parties. In 2005, approximately 7% of Generation's electric supply was generated from Generation's owned fossil and hydroelectric generating facilities. The majority of this output was dispatched to support Generation's power marketing activities. For additional information regarding Generation's electric generating facilities, see ITEM 2. Properties—Generation of Exelon's 2005 Form 10-K.

Licenses. Fossil generation plants are generally not licensed and, therefore, the decision on when to retire plants is, fundamentally, a commercial one. Hydroelectric plants are licensed by the FERC. The Muddy Run and Conowingo facilities have licenses that expire in September 2014. Generation is in the process of performing pre-application analyses and anticipates filing a Notice of Intent to renew the licenses in 2009 pursuant to FERC regulations.

Insurance. Generation does not purchase business interruption insurance for its wholly owned fossil and hydroelectric operations. For its other types of insured losses, Generation is self-insured to the extent that losses are within the policy deductible or exceed the amount of insurance maintained. Such losses could have a material adverse effect on Exelon and Generation's financial condition and their results of operations and cash flows. For information regarding property insurance, see ITEM 2. Properties—Generation of Exelon's 2005 Form 10-K.

Long-Term Contracts

In addition to energy produced by owned generation assets, Generation sells electricity purchased under the long-term contracts described below:

Seller	Location	Expiration	Capacity (MWs)
Kincaid Generation, LLC	Kincaid, Illinois	2011	1,108
Tenaska Georgia Partners, LP	Franklin, Georgia	2030	925
Tenaska Frontier, Ltd	Shiro, Texas	2020	830
Green Country Energy, LLC	Jenks, Oklahoma	2022	795
Elwood Energy, LLC	Elwood, Illinois	2012	772
Lincoln Generating Facility, LLC	Manhattan, Illinois	2011	664
Reliant Energy Aurora, LP	Aurora, Illinois	2008	600
Others [(a)]	Various	2006 to 2023	2,497
Total			8,191

(a) Includes long-term capacity contracts with nine counterparties.

Federal Power Act

The Federal Power Act gives the FERC exclusive rate-making jurisdiction over wholesale sales of electricity and the transmission of electricity in interstate commerce. Pursuant to the Federal Power Act, all public utilities subject to the FERC's jurisdiction are required to file rate schedules with the FERC with respect to wholesale sales and transmission of electricity. Transmission tariffs established under FERC regulation give Generation access to transmission lines that enable it to participate in competitive wholesale markets.

Because Generation sells power in the wholesale markets, Generation is a public utility for purposes of the Federal Power Act and is required to obtain the FERC's acceptance of the rate schedules for wholesale sales of electricity. In 2000, Generation received authorization from the FERC to sell power at market-based rates. As is customary with market-based rate schedules, the FERC reserved the right to suspend market-based rate authority on a retroactive basis if it subsequently determined that Generation or any of its affiliates violated the terms and conditions of its tariff or the Federal Power Act. The FERC is also authorized to order refunds if it finds that the market-based rates are not just and reasonable under the Federal Power Act.

For a number of years, the FERC has been encouraging the voluntary formation of RTOs, such as PJM, to provide transmission service across multiple transmission systems. The intended benefits of establishing these entities include managing transmission congestion, developing larger wholesale markets for energy and capacity, and the elimination or reduction of transmission charges imposed by successive transmission systems when wholesale generators cross several transmission systems to deliver capacity.

To date, PJM, the Midwest ISO, and ISO New England, have been approved as RTOs. Because of some states' opposition to imposition of centralized energy and capacity markets, the new FERC Chairman has been seeking to enhance the independence of transmission operations without the overlay of centralized markets.

Exelon supports the development of RTOs and implementation of standard market protocols but cannot predict their success or whether they will lead to the development of the envisioned large, successful wholesale markets. The FERC issued a final rule establishing standardized generator interconnection policies and procedures. Under this interconnection policy generators will benefit from not having to deal on a case-by-case basis with different and sometimes inconsistent requirements of different transmission providers.

In 2004, the FERC implemented market power tests for suppliers to qualify to sell power at market-based rates. These new tests, the market share test and the pivotal supplier test, must both be passed by Generation, or market power mitigation must be imposed for Generation to continue to make sales of capacity and energy in the wholesale market at market-based rates. The FERC allows the relevant geographic market to include a RTO's footprint, and Generation used an expanded PJM footprint as the relevant market.

On July 5, 2005, the FERC approved Generation's continued authority to charge market-based rates for wholesale sales of electricity, including to its affiliates ComEd and PECO. In the same order, the FERC stated that Generation had failed to address the affiliate abuse prong of the FERC's market-based rate eligibility test and used that statement as the basis for instituting a proceeding under the provision of the Federal Power Act, Section 206 and establishing a refund effective date of July 26, 2005 in the event that the FERC ultimately found that Generation did not, in fact, qualify for market-based rates. The FERC ordered Generation to make a compliance filing within 30 days of the order addressing the affiliate abuse and reciprocal dealing prong of the market-based rate test.

On August 4, 2005, Generation filed a Petition for Rehearing asking the FERC to rescind the part of its market-based rate order that had opened a Section 206 investigation into the issue of affiliate abuse and had established a refund effective date. Generation had addressed the affiliate abuse issue in its original November 2003 triennial update filing. The September 2004 filing had addressed only the new generation market power issue, as the FERC had directed. In the August 2005 filing, Generation noted the original reference in the September 2004 filing to the fact that the FERC had previously found that circumstances existed that guarded against affiliate abuse. Generation further noted that as of both the September 2004 and August 2005 filings there had been no change in the circumstances cited in the FERC's original order granting authority to Generation to sell electricity at market-based rates. Generation's pleading asked the FERC to either grant the rehearing request or to consider the August filing to be the required compliance filing.

The July 2005 market-based rate order also directed Exelon to make compliance filings within 30 days of the order amending the market-based rate tariffs of Exelon's various subsidiaries to include prohibiting sales of electricity to Public Service Electric and Gas Company (PSE&G), PSEG's regulated utility, unless specific authority were sought for such sales under Section 203 of the Federal Power Act. These compliance filings were made in accordance with the Order.

The Energy Policy Act of 2005. The Energy Policy Act, which was signed into law on August 8, 2005, implements several significant changes intended to improve electric reliability, promote investment in electric facilities, streamline electric regulation, improve wholesale competition, address problems identified in the western energy crisis and Enron collapse, promote fuel diversity and cleaner fuel sources, and promote greater efficiency in electric generation, delivery and use.

The Energy Policy Act, through amendment of the Federal Power Act, also transfers to the FERC certain additional authority. The FERC obtains new authority to review the acquisition or merger of generating facilities, along with the responsibility to address more explicitly cross-subsidization issues in these situations. The FERC now has the authority to approve siting of electric transmission facilities located in national interest electric transmission corridors if states cannot or will not act in a timely manner to approve siting. The Energy Policy Act also creates a self-regulating electric reliability organization with the FERC oversight to enforce reliability rules.

Fuel

The following table shows sources of electric supply in gigawatthours (GWhs) for 2005 and estimated for 2006:

	Source of Electric Supply	
	2005	2006 (Est.)
Nuclear units	137,936	137,832
Purchases—non-trading portfolio	42,623	50,098
Fossil and hydroelectric units	13,778	13,891
Total supply	194,337	201,821

The fuel costs for nuclear generation are substantially less than for fossil-fuel generation. Consequently, nuclear generation is generally the most cost-effective way for Generation to meet its commitment to supply the requirements of ComEd and PECO, some of Exelon Energy's requirements, and for sales to other utilities.

The cycle of production and utilization of nuclear fuel includes the mining and milling of uranium ore into uranium concentrates, the conversion of uranium concentrates to uranium hexafluoride, the enrichment of the uranium hexafluoride and the fabrication of fuel assemblies. Generation has uranium concentrate inventory and supply contracts sufficient to meet all of its uranium concentrate requirements through 2008. Generation's contracted conversion services are sufficient to meet all of its uranium conversion requirements through 2008. All of Generation's enrichment requirements have been contracted through 2010. Contracts for fuel fabrication have been obtained through 2008. Generation does not anticipate difficulty in obtaining the necessary uranium concentrates or conversion, enrichment or fabrication services for its nuclear units.

Generation obtains approximately 40% of its uranium enrichment services from European suppliers. There is an ongoing trade action by USEC, Inc. alleging dumping in the United States against European enrichment services suppliers. In January 2002, the U.S. International Trade Commission determined that USEC, Inc. was "materially injured or threatened with material injury" by low-enriched uranium exported by European suppliers. The U.S. Department of Commerce has assessed countervailing and anti-dumping duties against the European suppliers. Both USEC, Inc. and the European suppliers have appealed these decisions. Generation is uncertain at this time as to the outcome of the pending appeals; however, as a result of these actions, Generation may incur higher costs for uranium enrichment services necessary for the production of nuclear fuel.

Coal is obtained for coal-fired plants primarily through annual contracts with the remainder supplied through either short-term contracts or spot-market purchases.

Natural gas requirements for operating stations are procured through annual, monthly and spot-market purchases. Some fossil generation stations can use either oil or gas as fuel. Fuel oil inventories are managed so that in the winter months sufficient volumes of fuel are available in the event of extreme weather conditions and during the remaining months to take advantage of favorable market pricing.

Generation uses financial instruments to mitigate price risk associated with commodity price exposures. Generation also hedges forward price risk with both over-the-counter and exchange-traded instruments.

Power Team

Generation's wholesale operations include the physical delivery and marketing of power obtained through its generation capacity, and long-, intermediate- and short-term contracts. Generation seeks to maintain a net positive supply of energy and capacity, through ownership of generation assets and purchase power and lease agreements, to protect it from the potential operational failure of one of its owned or contracted power generating units. Generation has also contracted for access to additional generation through bilateral long-term PPAs. These agreements are commitments related to power generation of specific generation plants and/or are dispatchable in nature similar to asset ownership. Generation enters into PPAs with the objective of obtaining low-cost energy supply sources to meet its physical delivery obligations to customers. Power Team may buy power to meet the energy demand of its customers, including ComEd and PECO. These purchases may be made for more than the energy demanded by Power Team's customers. Power Team then sells this open position, along with capacity not used to meet customer demand, in the wholesale energy market. Generation has also purchased transmission service to ensure that it has reliable transmission capacity to physically move its power supplies to meet customer delivery needs.

Power Team also manages the price and supply risks for energy and fuel associated with generation assets and the risks of power marketing activities. The maximum length of time over which cash flows related to energy commodities are currently being hedged is three years. Generation's hedge ratio in 2006 for its energy marketing portfolio is approximately 88%. This hedge ratio represents the percentage of forecasted aggregate annual generation supply that is committed to firm sales, including sales to ComEd's and PECO's retail load. The hedge ratio is not fixed and will vary from time to time depending upon market conditions, demand and volatility. During summer peak demand periods, the hedge ratio declines to assure Generation's commitment to meet demand in ComEd's and PECO's regions. For the portion of generation supply that is unhedged, fluctuations in market price of energy will cause volatility in Generation's results of operations.

Power Team also uses financial and commodity contracts for proprietary trading purposes but this activity accounts for only a small portion of Power Team's efforts. The trading portfolio is subject to a risk management policy that includes stringent risk management limits including volume, stop-loss and value-at-risk limits to manage exposure to market risk. Additionally, the corporate risk management group and Exelon's Risk Management Committee (RMC) monitor the financial risks of the power marketing activities.

At December 31, 2005, Generation's long-term commitments relating to the purchase and sale of energy, capacity and transmission rights from and to unaffiliated utilities and others were as follows:

(in millions)	Net Capacity Purchases (a)	Power Only Sales	Power Only Purchases from Non-Affiliates	Transmission Rights Purchases (b)
2006	$ 616	$2,783	$1,508	$ 7
2007	527	947	491	3
2008	460	80	194	—
2009	434	18	194	—
2010	436	19	194	—
Thereafter	3,391	—	355	—
Total	$5,864	$3,847	$2,936	$ 10

(a) Net capacity purchases include tolling agreements that are accounted for as operating leases. Amounts presented in the commitments represent Generation's expected payments under these arrangements at December 31, 2005. Expected payments include certain capacity charges which are conditional on plant availability.

(b) Transmission rights purchases include estimated commitments in 2006 for additional transmission rights that will be required to fulfill firm sales contracts.

In connection with the 2001 corporate restructuring, Generation entered into a PPA, as amended, with ComEd under which Generation has agreed to supply all of ComEd's load requirements through 2006. Under the ComEd PPA, prices for energy vary depending upon the time of day and month of delivery. Subsequent to 2006, ComEd expects to procure all of its supply from market sources, which could include Generation. Additionally, Generation has a PPA with PECO under which Generation has agreed to supply PECO with substantially all of PECO's electric supply needs through 2010. PECO has also assigned its rights and obligations under various PPAs and fuel supply agreements to Generation. Generation supplies electricity to PECO from the transferred generation assets, assigned PPAs and other market sources. Subsequent to 2010, PECO expects to procure all of its electricity from market sources, which could include Generation.

Capital Expenditures

Generation's business is capital intensive and requires significant investments in energy generation and in other internal infrastructure projects. Generation's estimated capital expenditures for 2006 are as follows:

(in millions)	
Production plant	$ 604
Nuclear fuel	511
Total	$1,115

PART II

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

MARKET FOR OUR COMMON EQUITY AND RELATED STOCKHOLDER MATTERS

Exelon's common stock is listed on the New York Stock Exchange. As of January 31, 2006, there were 667,233,091 shares of common stock outstanding and approximately 160,754 shareholders of common stock of record.

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

	2005				2004			
	Fourth Quarter	Third Quarter	Second Quarter	First Quarter	Fourth Quarter	Third Quarter	Second Quarter	First Quarter
High price	$56.00	$57.46	$52.01	$47.18	$44.90	$37.90	$34.89	$34.43
Low price	46.62	49.60	44.14	41.77	36.73	32.69	30.92	32.18
Close	53.14	53.44	51.33	45.89	44.07	36.69	33.29	34.43
Dividends	0.400	0.400	0.400	0.400	0.400	0.305	0.275	0.275

On July 22, 2005, Exelon's shareholders approved the issuance of Exelon common stock as contemplated by the Agreement and Plan of Merger, dated December 20, 2004, between Exelon and PSEG. Effective October 24, 2005, Exelon's Amended and Restated Articles of Incorporation were amended to increase the number of authorized shares of Exelon common stock from 1.2 billion to 2 billion.

Dividends

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

Under Illinois law, ComEd may not pay any dividend on its stock unless, among other things, "[its] earnings and earned surplus are sufficient to declare and pay same after provision is made for reasonable and proper reserves," or unless it has specific authorization from the ICC. At December 31, 2005, Exelon had retained earnings of $3.2 billion, which includes ComEd's retained deficit of $(81) million consisting of $1,099 million of retained earnings appropriated for future dividends offset by unappropriated deficit of $(1,180) million, PECO's retained earnings of $649 million and Generation's undistributed earnings of $1,002 million.

PECO's Articles of Incorporation prohibit payment of any dividend on, or other distribution to the holders of, common stock if, after giving effect thereto, the capital of PECO represented by its common stock together with its retained earnings is, in the aggregate, less than the involuntary liquidating value of its then outstanding preferred stock. At December 31, 2005, such capital was $2.8 billion and amounted to about 32 times the liquidating value of the outstanding preferred stock of $87 million.

PECO may not declare dividends on any shares of its capital stock in the event that: (1) it exercises its right to extend the interest payment periods on the subordinated debentures which were issued to PEC L.P. or PECO Trust IV; (2) it defaults on its guarantee of the payment of distributions on the Series D Preferred Securities of PEC L.P. or the preferred trust securities of PECO Trust IV; or (3) an event of default occurs under the Indenture under which the subordinated debentures are issued (see ITEM 1. Business—Other Subsidiaries of ComEd and PECO with Publicly Held Securities of Exelon's 2005 Form 10-K).

The following table sets forth Exelon's quarterly cash dividends per share paid during 2005 and 2004:

(per share)	2005 4th Quarter	2005 3rd Quarter	2005 2nd Quarter	2005 1st Quarter	2004 4th Quarter	2004 3rd Quarter	2004 2nd Quarter	2004 1st Quarter
Exelon	$0.400	$0.400	$0.400	$0.400	$0.400	$0.305	$0.275	$0.275

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

(in millions)	2005 4th Quarter	2005 3rd Quarter	2005 2nd Quarter	2005 1st Quarter	2004 4th Quarter	2004 3rd Quarter	2004 2nd Quarter	2004 1st Quarter
ComEd	$146	$107	$107	$138	$137	$113	$104	$103
PECO	122	116	116	115	115	96	90	90
Generation	108	430	80	239	335	61	55	54

In July 2004, the Exelon Board of Directors approved a policy of targeting a dividend payout ratio of 50% to 60% of ongoing earnings. On January 24, 2006, the Exelon Board of Directors declared a regular quarterly dividend of $0.40 per share on Exelon's common stock. The dividend is payable on March 10, 2006, to shareholders of record of Exelon at 5:00 p.m. Eastern Standard Time on February 15, 2006.

The Board of Directors of Exelon also declared a regular quarterly dividend of $0.40 per share on Exelon's common stock for the second quarter of 2006. The dividend is payable on June 10, 2006, to shareholders of record of Exelon at 5:00 p.m. Eastern Standard Time on May 15, 2006.

The Board of Directors of Exelon has also declared an additional dividend payable within 30 days after closing of the Merger if the Merger closes after February 15, 2006 and on or before May 15, 2006. The dividend will be pro-rated, with shareholders receiving $0.00449 per share per day from February 15, 2006 to the closing of the Merger. This pro rata dividend is equivalent to $0.40 per share for the full quarter. If the Merger is not closed on or before May 15, 2006, the Board of Directors of Exelon expects to declare and pay a similar pro rata dividend for the period after May 15, 2006.

The Board of Directors of Exelon also changed its policy for dividend record and payment dates that will take effect after the closing of the Merger. Currently, dividend record dates are the fifteenth day of the second month of the quarter, and payment dates are the tenth day of the third month of the quarter. After the closing of the Merger, when the dividend is increased as required by the Merger Agreement, the record date will be the eighth day of the third month of a quarter, and the payment date will be the last business day of the third month of a quarter. The Board expects that there will be another pro-rated dividend for the period from the Merger closing date to the first regular record date under the new dividend schedule. This post-closing pro-rated dividend will be calculated at the increased dividend rate and will be paid on the first regular payment date under the new dividend schedule. The use of pro-rated dividends is intended to keep shareholders whole with respect to their dividends.

SELECTED FINANCIAL DATA

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

in millions, except for per share data	For the Years Ended December 31, 2005	2004	2003	2002	2001
Statement of Income data:					
Operating revenues	$15,357	$14,133	$15,148	$14,060	$13,978
Operating income	2,724	3,499	2,409	3,280	3,406
Income from continuing operations	$ 951	$ 1,870	$ 892	$ 1,690	$ 1,448
Income (loss) from discontinued operations	14	(29)	(99)	(20)	(32)
Income before cumulative effect of changes in accounting principles	965	1,841	793	1,670	1,416
Cumulative effect of changes in accounting principles (net of income taxes)	(42)	23	112	(230)	12
Net income [(a), (b)]	$ 923	$ 1,864	$ 905	$ 1,440	$ 1,428
Earnings per average common share (diluted):					
Income from continuing operations	$ 1.40	$ 2.79	$ 1.36	$ 2.60	$ 2.24
Income (loss) from discontinued operations	0.02	(0.04)	(0.15)	(0.03)	(0.05)
Income before cumulative effect of changes in accounting principles	1.42	2.75	1.21	2.57	2.19
Cumulative effect of changes in accounting principles (net of income taxes)	(0.06)	0.03	0.17	(0.35)	0.02
Net income	$ 1.36	$ 2.78	$ 1.38	$ 2.22	$ 2.21
Dividends per common share	$ 1.60	$ 1.26	$ 0.96	$ 0.88	$ 0.91
Average shares of common stock outstanding—diluted	676	669	657	649	645

(a) Change between 2005 and 2004 is primarily due to the goodwill impairment charge of $1.2 billion in 2005.
(b) Change between 2004 and 2003 is primarily due to the impairment of Boston Generating, LLC long-lived assets of $945 million in 2003.

in millions	December 31, 2005	2004	2003	2002	2001
Balance Sheet data:					
Current assets	$ 4,637	$ 3,880	$ 4,524	$ 4,096	$ 3,707
Property, plant and equipment, net	21,981	21,482	20,630	17,957	14,665
Noncurrent regulatory assets	4,386	4,790	5,226	5,546	5,774
Goodwill [(a)]	3,475	4,705	4,719	4,992	5,335
Other deferred debits and other assets	7,910	7,867	6,800	5,249	5,460
Total assets	$42,389	$42,724	$41,899	$37,840	$34,941
Current liabilities	$ 6,563	$ 4,836	$ 5,683	$ 5,845	$ 4,342
Long-term debt, including long-term debt to financing trusts	11,760	12,148	13,489	13,127	12,879
Regulatory liabilities	2,170	2,204	1,891	486	225
Other deferred credits and other liabilities	12,683	13,918	12,246	9,968	8,749
Minority interest	1	42	—	77	31
Preferred securities of subsidiaries [(b)]	87	87	87	595	613
Shareholders' equity	9,125	9,489	8,503	7,742	8,102
Total liabilities and shareholders' equity	$42,389	$42,724	$41,899	$37,840	$34,941

(a) Change between 2005 and 2004 is primarily due to the goodwill impairment charge of $1.2 billion in 2005.
(b) Due to the adoptions of FIN 46 and FIN 46-R in 2003, the mandatorily redeemable preferred securities of ComEd and PECO were reclassified as long-term debt to financing trusts in 2003.

Exelon Corporation

Executive Overview

Financial Results. Exelon's net income was $923 million in 2005 as compared to $1,864 million in 2004 and diluted earnings per average common share were $1.36 for 2005 as compared to $2.78 for 2004. The decrease was primarily due to the following:

- a $1.2 billion impairment charge associated with ComEd's goodwill;
- losses for the cumulative effect of adopting FASB Interpretation No. (FIN) 47, "Accounting for Conditional Asset Retirement Obligations" (FIN 47);
- an increase to the reserve for estimated future asbestos-related bodily injury claims;
- increased depreciation and amortization expense, including CTC amortization at PECO;
- the gain associated with the sale of Boston Generating recorded in 2004;
- a gain recorded in 2004 as a cumulative effect of a change in accounting principle due to the adoption of FIN 46 (revised December 2003), "Consolidation of Variable Interest Entities" (FIN 46-R); and
- a gain recorded in 2004 from the reimbursement of costs incurred prior to 2004 under a settlement with DOE related to spent nuclear fuel storage.

The factors driving the overall decrease in net income above were partially offset by the following:

- higher margins on Generation's wholesale market sales;
- favorable weather conditions in Exelon's service territories;
- reduced severance and severance-related charges;
- lower pension expense as a result of a discretionary pension contribution made in the first quarter of 2005; and
- losses associated with 2004 debt retirements at ComEd.

Investment Strategy. In 2005, Exelon continued to follow a disciplined approach in investing to maximize earnings and cash flows from its assets and businesses, while selling those investments that do not meet its strategic goals. Highlights from 2005 include the following:

- *Proposed Merger with PSEG*—On December 20, 2004, Exelon entered into a Merger Agreement with PSEG, and shareholders of both companies approved the transaction in July 2005. The Merger also received approval from regulatory agencies in New York, Texas and Connecticut, in addition to the FERC approval in June 2005. On September 13, 2005, Exelon announced that PECO had reached a partial settlement, subject to approval, with some but not all of the parties related to the Pennsylvania review of the Merger. The PAPUC approved the settlement and the Merger on January 27, 2006.

  In New Jersey, hearings for the Merger review have been extended; they are expected to conclude on March 27, 2006. Settlement discussions began in December 2005 and are expected to resume after the hearings conclude. Scheduled dates for the Administrative Law Judge's (ALJ) initial decision and final order from the NJBPU also may be extended, but no firm dates have been set.

Other remaining regulatory reviews include the U.S. Department of Justice (DOJ). Exelon will attempt to reach a settlement that satisfactorily resolves issues and allows the Merger to close in the second quarter of 2006. However, in the absence of an earlier settlement, Exelon expects that the closing of the Merger will occur in the third quarter of 2006. See Note 3 of Exelon's Notes to Consolidated Financial Statements for further information.

- *Sithe*—On January 31, 2005, subsidiaries of Generation completed a series of transactions that resulted in Generation's sale of its investment in Sithe. Specifically, subsidiaries of Generation closed on the acquisition of Reservoir Capital Group's 50% interest in Sithe and the sale of 100% of Sithe to Dynegy. See Note 3 of Exelon's Notes to Consolidated Financial Statements for further information regarding the sale of Generation's investment in Sithe.

Financing Activities. During 2005, Exelon met its capital resource requirements primarily with internally generated cash. When necessary, Exelon obtains funds from external sources, including capital markets, and through bank borrowings. On March 7, 2005, Exelon entered into a $2 billion term loan agreement to fund pension contributions in the first quarter of 2005. On April 1, 2005, Exelon entered into a $500 million term loan agreement that was subsequently fully borrowed to reduce the $2 billion term loan referenced above. On June 9, 2005, Exelon issued and sold $1.7 billion of senior debt securities pursuant to its senior debt indenture, dated as of May 1, 2001, consisting of $400 million of 4.45% senior notes due 2010, $800 million of 4.90% senior notes due 2015 and $500 million of 5.625% senior notes due 2035. The net proceeds from the sale of the notes were used to repay the $1.5 billion in remaining principal due on the $2 billion term loan agreement and $200 million of the $500 million term loan agreement. See Notes 10 and 11 of Exelon's Notes to Consolidated Financial Statements for further discussion.

Regulatory Developments—Illinois. As discussed in General Description of Our Business and Note 4 of Exelon's Notes to Consolidated Financial Statements, on January 24, 2006, the ICC, by a unanimous vote, approved a reverse-auction competitive bidding process for procurement of power by ComEd for the time period after 2006. To mitigate the impact on its residential customers of transitioning to this process, ComEd has offered to develop a "cap and deferral" proposal to ease the impact of the expected increase in rates on residential customers, some or all of which could require regulatory or legislative approval to implement. Several parties have indicated that they will petition the ICC for rehearing and will challenge the ICC decision in court. ComEd has also petitioned for rehearing of the ICC decision on certain issues, but that petition was denied by the ICC on February 8, 2006. It is also possible that interested parties could introduce legislation in Illinois in attempt to modify the procurement process or the rates that ComEd may charge consumers for the power ComEd purchases to meet the needs of consumers. The Illinois General Assembly has held hearings concerning generation procurement after 2006, and it may take action on this issue.

ComEd also has filed and has pending a regulatory proceeding before the ICC, referred to as the Rate Case. The Rate Case seeks, among other things, to allocate the costs of delivering electricity and to adjust ComEd's rates for delivering electricity effective January 2, 2007. The Rate Case also proposes procedures under which ComEd will allocate the costs from the Procurement Case among ComEd customers. Several intervenors in the Rate Case, including the ICC staff and the Illinois Attorney General, have suggested, and provided testimony, that ComEd's rates should actually be reduced. The results of the Rate Case are not expected to be known until the third quarter of 2006.

Market-Based Rates Filing. On July 5, 2005, the FERC approved Generation's continued authority to charge market-based rates for wholesale sales of electricity, including to its affiliates ComEd and PECO. In the same order, the FERC stated that Generation had failed to address the affiliate abuse issue of the FERC's market-based rate eligibility test. On August 4, 2005, Generation filed a Petition for Rehearing asking the FERC to rescind that part of its market-based rate order. Generation expects the FERC to make a decision in 2006. If the FERC were to suspend Generation's market-based rate authority, Generation would be required to supply and implement a plan for mitigation of market power. FERC's default mitigation would require Generation to file and obtain FERC acceptance of cost-based rate schedules or schedules tied to a public index. In addition, the loss of market-based rate authority would subject Generation to the accounting, record-keeping and reporting requirements that are imposed on public utilities with cost-based rate schedules.

Repeal of PUHCA. Pursuant to the Energy Policy Act, PUHCA was repealed effective February 8, 2006. Under the Energy Policy Act, FERC obtained additional jurisdiction for merger review and for the review of affiliate transactions, and FERC's financing jurisdiction resumed to the extent that it was preempted by PUHCA. Exelon continues to review the effects of the Energy Policy Act and FERC's proposed rules with respect to future financing authority for its subsidiaries. To the extent that the SEC's jurisdiction under PUHCA preempted certain aspects of state regulation, the repeal of PUHCA permits the states in which Exelon and its subsidiaries operate to adopt additional regulations if they so choose, absent any preemption by the FERC.

See General Description of Our Business and Note 4 of Exelon's Notes to the Consolidated Financial Statements for information on other regulatory matters.

Outlook for 2006 and Beyond. Exelon's future financial results will be affected by a number of factors, including the following:

- Exelon expects the Merger will result in synergies, cost savings and operating efficiencies. Although Exelon expects to achieve these anticipated benefits of the Merger, achieving them, including synergies, is subject to a number of uncertainties. See ITEM 1A. Risk Factors within Exelon's 2005 Form 10-K for additional information.
- Certain governmental officials and consumer advocacy groups claim that ComEd's retail rates for electricity should not be based solely on its cost to procure electricity and capacity in the wholesale market. Additionally, certain parties to ComEd's Rate Case proceeding have indicated ComEd's rates for delivering energy should be reduced and not increased. If the price at which ComEd is allowed to sell electricity beginning in 2007 is below ComEd's cost to procure and deliver electricity, or if ComEd is unable to recover its costs and investment through the Rate Case, there may be material adverse consequences to ComEd and, possibly, Exelon. However, the ICC's unanimous approval of the reverse-auction process, barring any successful appeals or change in law, should provide ComEd with stability and greater certainty that it will be able to procure energy and pass through the costs of that energy to ComEd's customers beginning in 2007 through a transparent market mechanism in the reverse-auction process. The results of the Rate Case should be known during the third quarter of 2006.
- As of December 31, 2005, Hurricanes Katrina and Rita have not significantly impacted Exelon's results of operations and cash flows. However, Hurricanes Katrina and Rita are expected to impact the already increasing costs of certain supplies and the lead time to order these supplies in 2006. As a result, costs of such supplies could be $30 million to $40 million higher in 2006 compared to 2005, impacting results of operations and cash flows.
- Exelon, through three wholly owned subsidiaries, has investments in synthetic fuel-producing facilities. Section 45k (formerly Section 29) of the Internal Revenue Code provides tax credits for the sale of synthetic fuel produced from coal. However, Section 45k contains a provision under which credits are phased out (i.e., eliminated) in the event crude oil prices for a year exceed certain thresholds.

  The estimated annual average price per barrel of oil on the New York Mercantile Exchange, Inc. index (NYMEX) would have to exceed $59 and $61 in 2006 and 2007, respectively, for a phase-out to begin. In 2005, the estimated annual average price per barrel of $57 did not exceed the bottom of the phase-out range of $58. As a result, Exelon's interests in synthetic fuel-producing facilities increased Exelon's net income by $81 million during 2005. Based on the 2006 and 2007 NYMEX futures prices at December 31, 2005, Exelon estimates there will be a phase out of tax credits of 38% and 36% in 2006 and 2007, respectively. This would decrease Exelon's net income as compared to 2005 by as much as $38 million and $36 million in 2006 and 2007, respectively. These estimates can change significantly due to the volatility in oil prices. See Liquidity and Capital Resources for further discussion.

Critical Accounting Policies and Estimates

The preparation of financial statements in conformity with GAAP requires that management apply accounting policies and make estimates and assumptions that affect results of operations and the amounts of assets and liabilities reported in the financial statements. Management discusses these policies, estimates and assumptions within its Accounting and Disclosure Governance Committee on a regular basis and provides periodic updates on management decisions to the Audit Committee of the Exelon Board of Directors. Management believes that the areas described below require significant judgment in the application of accounting policy or in making estimates and assumptions in matters that are inherently uncertain and that may change in subsequent periods. Further discussion of the application of these accounting policies can be found in the Registrants' Notes to Consolidated Financial Statements.

Asset Retirement Obligations (ARO) (Exelon, ComEd, PECO and Generation)

Nuclear Decommissioning (Exelon and Generation)

Generation must make significant estimates and assumptions in accounting for its obligation to decommission its nuclear generating plants in accordance with SFAS No. 143, "Accounting for Asset Retirement Obligations" (SFAS No. 143).

SFAS No. 143 requires that Generation estimate the fair value of its obligation for the future decommissioning of its nuclear generating plants. To estimate that fair value, Generation uses a probability-weighted, discounted cash flow model which considers multiple outcome scenarios based upon significant estimates and assumptions embedded in the following:

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

Cost Escalation Studies. Generation uses cost escalation factors to escalate the estimated base year decommissioning costs, which are included in the decommissioning cost studies discussed above, through the decommissioning period for each of the units. Cost escalation studies are used to determine escalation factors and are based on inflation indices for labor, equipment and materials, energy and low-level radioactive waste disposal costs. Cost escalation studies are updated on an annual basis.

Probabilistic Cash Flow Models. Generation's probabilistic cash flow models include the assignment of probabilities to various cost levels and various decommissioning timing scenarios. Probabilities assigned to cost levels include an assessment of the likelihood of actual costs plus 15% or minus 10% over the base cost scenario. The probabilities assigned to various timing scenarios incorporate the likelihood of continued operation through current license lives or through anticipated license renewals and the timing of DOE acceptance of spent nuclear fuel for permanent disposal.

Discount Rates. The probability-weighted estimated future cash flows using these various scenarios are discounted using credit-adjusted, risk-free rates applicable to the various businesses in which each of the nuclear units originally operated.

Changes in the assumptions underlying the foregoing items could materially affect the decommissioning obligation recorded with a corresponding change to the asset retirement cost (ARC) asset. However, if the ARO relates to retired units, which have no remaining useful life and, likewise, no existing ARC, the offset may be recorded in current period earnings. Changes in the assumptions could affect future updates to the decommissioning obligation. For example, the 20-year average cost escalation rates used in the latest ARO calculation were approximately 3% to 4%. A uniform increase in these escalation rates of 25 basis points would increase the total ARO recorded by Exelon by approximately 9% or more than $350 million. Under SFAS No. 143, the nuclear decommissioning obligation is adjusted on an ongoing basis due to the passage of time and revisions to either the timing or amount of the original estimate of the future undiscounted cash flows required to decommission the nuclear plants. For more information regarding the adoption and ongoing application of SFAS No. 143, see Notes 1 and 13 of Exelon's Notes to Consolidated Financial Statements.

Conditional ARO (Exelon, ComEd, PECO and Generation)

As of December 31, 2005, Exelon, ComEd, PECO and Generation adopted FASB Interpretation No. 47, "Accounting for Conditional Asset Retirement Obligations" (FIN 47). FIN 47 clarified that a legal obligation associated with the retirement of a long-lived asset whose timing and/or method of settlement are conditional on a future event is within the scope of SFAS No. 143. Under FIN 47, Exelon, ComEd, PECO and Generation are required to record a conditional ARO at its estimated fair value if that fair value can be reasonably estimated. As of December 31, 2005, Exelon, ComEd, PECO and Generation had liabilities of $236 million, $151 million, $20 million and $65 million, respectively, associated with their conditional AROs.

The adoption of FIN 47 required the Registrants to update an existing inventory, originally created for the adoption of SFAS No. 143, and to determine which, if any, of the conditional AROs could be reasonably estimated. The ability to reasonably estimate a conditional ARO was a matter of management judgment, based upon management's ability to estimate a settlement date or range of settlement dates, a method or potential method of settlement and probabilities associated with the potential dates and methods of settlement of its conditional AROs. In determining whether their conditional AROs could be reasonably estimated, management considered the Registrants' past practices, industry practices, management's intent and the estimated economic lives of the assets. The fair value of the conditional AROs was then estimated using an expected present value technique. Additionally, Exelon, ComEd and PECO assessed the likelihood of recovering these obligations from customers which led to the recognition of regulatory assets. Changes in management's assumptions regarding settlement dates, settlement methods, assigned probabilities or recovery mechanisms could have a material effect on the liabilities recorded by each Registrant at December 31, 2005 as well as the associated cumulative effect of a change in accounting principle recorded at Exelon, ComEd, PECO and Generation and the associated regulatory assets recorded at Exelon, ComEd and PECO. The liabilities associated with conditional AROs will be adjusted on an ongoing basis due to the passage of time, new laws and regulations and revisions to either the timing or amount of the original estimates of undiscounted cash flows. These adjustments could have a significant impact on the Consolidated Balance Sheets and Consolidated Statements of Income of the Registrants. For more information regarding the adoption and ongoing application of FIN 47, see Notes 1 and 14 of Exelon's Notes to Consolidated Financial Statements.

Asset Impairments (Exelon, ComEd, PECO and Generation)

Goodwill (Exelon and ComEd)

As of December 31, 2004, Exelon and ComEd had approximately $4.7 billion of goodwill, which related entirely to the goodwill recorded upon the acquisition of ComEd. Exelon and ComEd perform assessments for impairment of their goodwill at least annually, or more frequently if events or circumstances indicate that goodwill might be impaired. Application of the goodwill impairment test requires management's judgments, including the identification of reporting units, assigning assets and liabilities to reporting units, assigning goodwill to reporting units, and determining the fair value of each reporting unit.

Exelon and ComEd performed their annual assessments of goodwill impairment as of November 1, 2005 and determined that goodwill was impaired by $1.2 billion. Exelon assesses goodwill impairment at its ComEd reporting unit; accordingly, a goodwill impairment charge at ComEd is fully reflected in Exelon's results of operations. After reflecting the impairment, Exelon and ComEd have $3.5 billion of goodwill as of December 31, 2005.

In the assessments, Exelon and ComEd estimated the fair value of the ComEd reporting unit using a probability-weighted, discounted cash flow model with multiple scenarios. The fair value incorporates management's assessment of current events and expected future cash flows. The 2005 impairment was driven by changes in the fair value of ComEd's purchase power agreement with Generation, the upcoming end of ComEd's transition period and related transition revenues, regulatory uncertainty in Illinois as of November 1, 2005, anticipated increases in capital expenditures in future years and decreases in market valuations of comparable companies that are utilized to estimate the fair value of ComEd. Changes in assumptions regarding these variables or in the assessment of how they interrelate could produce a different impairment result, which could be material. For example, a hypothetical decrease of approximately 10% in ComEd's expected discounted cash flows would result in additional impairment for both ComEd and Exelon of $1.2 billion. An additional impairment would require Exelon and ComEd to further reduce both goodwill and current period earnings by the amount of the impairment.

Long-Lived Assets (Exelon, ComEd, PECO and Generation)

Exelon, ComEd, PECO and Generation evaluate the carrying value of their long-lived assets, excluding goodwill, when circumstances indicate the carrying value of those assets may not be recoverable. The review of long-lived assets for impairment requires significant assumptions about operating strategies and estimates of future cash flows, which require assessments of current and projected market conditions. For the generation business, forecasting future cash flows requires assumptions regarding forecasted commodity prices for the sale of power and costs of fuel. A variation in the assumptions used could lead to a different conclusion regarding the realizability of an asset and, thus, could have a significant effect on the consolidated financial statements. An impairment would require the affected registrant to reduce both the long-lived asset and current period earnings by the amount of the impairment.

Investments (Exelon, ComEd, PECO and Generation)

Exelon, ComEd, PECO and Generation had approximately $6,398 million, $75 million, $95 million and $5,705 million, respectively, of investments, including investments held in nuclear decommissioning trust funds, recorded as of December 31, 2005. Exelon, ComEd, PECO and Generation consider investments to be impaired when a decline in fair value below cost is judged to be other-than-temporary. If the cost of an investment exceeds its fair value, they evaluate, among other factors, general market conditions, the duration and extent to which the fair value is less than cost, as well as their intent and ability to hold the investment. The Registrants may also consider specific adverse conditions related to the financial health of and business outlook for the investee when reviewing an investment for impairment. An impairment would require the affected registrant to reduce both the investment and current period earnings by the amount of the impairment.

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

The Registrants have a significant investment in electric generation assets and electric and natural gas transmission and distribution assets. Depreciation of these assets is generally provided over their estimated service lives on a straight-line basis using the composite method. The estimation of service lives requires management judgment regarding the period of time that the assets will be in use. As circumstances warrant, depreciation estimates are reviewed to determine if any changes are needed. Changes to depreciation estimates in future periods could have a significant impact on the amount of property, plant and equipment recorded and the depreciation charged to the financial statements.

Historically, Generation has extended the estimated service lives of certain nuclear-fuel generating facilities based upon Generation's intent to apply for license renewals for these facilities. While Generation has received license renewals for certain facilities, and has applied for or expects to apply for and obtain approval of license renewals for the remaining facilities, circumstances may arise that would prevent Generation from obtaining additional license renewals. A change in depreciation estimates resulting from Generation's inability to receive additional license renewals could have a significant effect on Generation's results of operations.

In August 2005, PECO filed a depreciation rate study with the PAPUC. The impact of the new rates, based on the study, which will be effective March 2006, is not expected to be material.

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

Exelon sponsors defined benefit pension plans and postretirement welfare benefit plans applicable to essentially all ComEd, PECO, Generation and BSC employees and certain Enterprises employees. See Note 15 of Exelon's Notes to Consolidated Financial Statements for further information regarding the accounting for Exelon's defined benefit pension plans and postretirement welfare benefit plans.

The costs of providing benefits under these plans are dependent on historical information such as employee age, length of service and level of compensation and the actual rate of return on plan assets. Also, Exelon utilizes assumptions about the future, including the expected rate of return on plan assets, the discount rate applied to benefit obligations, rate of compensation increases and the anticipated rate of increase in health care costs.

The selection of key actuarial assumptions utilized in the measurement of the plan obligations and costs drives the results of the analysis and the resulting charges. The long-term expected rate of return on plan assets (EROA) assumption used in calculating pension cost was 9.00% in 2005, 2004 and 2003. The weighted average EROA assumption used in calculating other postretirement benefit costs was 8.30% in 2005 compared to a range of 8.33% to 8.35% in 2004 and 8.40% for 2003. A lower EROA is used in the calculation of other postretirement benefit costs, as the other postretirement benefit trust activity is partially taxable while the pension trust activity is non-taxable.

The discount rate for determining the plan obligations was 5.60%, 5.75% and 6.25% at December 31, 2005, 2004 and 2003, respectively. The discount rates at December 31, 2004 and 2003 were selected by reference to the Moody's Aa Corporate Bond Index adjusted to reflect the duration of expected future cash flows for pension and other postretirement welfare benefit payments. At

December 31, 2005, the discount rate was determined by developing a spot rate curve based on the yield to maturity of more than 400 Aa graded non-callable (or callable with make whole provisions) bonds with similar maturities to the related pension and other postretirement welfare benefit obligations. The spot rates are used to discount the estimated distributions under the pension and other postretirement welfare benefit plans. The discount rate is the single level rate that produces the same result as the spot rate curve.

The following tables illustrate the effects of changing the major actuarial assumptions discussed above (dollars in millions):

Change in Actuarial Assumption	Impact on Projected Benefit Obligation at December 31, 2005	Impact on Pension Liability at December 31, 2005	Impact on 2006 Pension Cost
Pension benefits			
Decrease discount rate by 0.5%	$683	$548	$50
Decrease rate of return on plan assets by 0.5%	—	—	45

Change in Actuarial Assumption	Impact on Other Postretirement Benefit Obligation at December 31, 2005	Impact on Postretirement Benefit Liability at December 31, 2005	Impact on 2006 Postretirement Benefit Cost
Postretirement benefits			
Decrease discount rate by 0.5%	$208	$—	$24
Decrease rate of return on plan assets by 0.5%	—	—	6

Assumed health care cost trend rates also have a significant effect on the costs reported for Exelon's postretirement benefit plans. To estimate the 2005 cost, Exelon assumed a health care cost trend rate of 9%, decreasing to an ultimate trend rate of 5% in 2010, compared to the 2004 assumption of 10%, decreasing to an ultimate trend rate of 4.5% in 2011. A one-percentage point change in assumed health care cost trend rates in 2005 would have had the following effects (dollars in millions):

Effect of a one percentage point increase in assumed health care cost trend	
on total service and interest cost components	$ 41
on postretirement benefit obligation	$ 399
Effect of a one percentage point decrease in assumed health care cost trend	
on total service and interest cost components	$ (30)
on postretirement benefit obligation	$(297)

The assumptions are reviewed at the beginning of each year during Exelon's annual review process and at any interim remeasurement of the plan obligations. The impact of assumption changes is reflected in the recorded pension and postretirement benefit amounts as they occur, or over a period of time if allowed under applicable accounting standards. As these assumptions change from period to period, recorded pension and postretirement benefit amounts and funding requirements could also change.

In 2005, Exelon incurred approximately $221 million in costs associated with its pension and postretirement benefit plans. The decrease in Exelon's pension and postretirement benefit costs in 2005 compared to 2004 and 2003 was primarily attributable to discretionary pension contributions of $2 billion made during the first quarter of 2005.

Regulatory Accounting (Exelon, ComEd and PECO)

Exelon, ComEd and PECO account for their regulated electric and gas operations in accordance with SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation" (SFAS No. 71), which requires Exelon, ComEd and PECO to reflect the effects of rate regulation in their financial statements. Use of SFAS No. 71 is applicable to utility operations that meet the following criteria: (1) third-party regulation of rates; (2) cost-based rates; and (3) a reasonable assumption that all costs will be recoverable from customers through rates. As of December 31, 2005, Exelon, ComEd and PECO have concluded that the operations of ComEd and PECO meet the criteria. If it is concluded in a future period that a separable portion of their businesses no longer meets the criteria, Exelon, ComEd and PECO are required to eliminate the financial statement effects of regulation for that part of their business, which would include the elimination of any or all regulatory assets and liabilities that had been recorded in their Consolidated Balance Sheets. The impact of not meeting the criteria of SFAS No. 71 could be material to the financial statements as a one-time extraordinary item and through impacts on continuing operations. See Note 4 of Exelon's Notes to Consolidated Financial Statements for further information regarding regulatory issues.

Regulatory assets represent costs that have been deferred to future periods when it is probable that the regulator will allow for recovery through rates charged to customers. Regulatory liabilities represent revenues received from customers to fund expected costs that have not yet been incurred. As of December 31, 2005, Exelon and PECO had recorded $4.4 billion of net regulatory assets within their Consolidated Balance Sheets. At December 31, 2005, Exelon and ComEd had recorded $2.2 billion of net regulatory liabilities within their Consolidated Balance Sheets. See Note 21 of Exelon's Notes to Consolidated Financial Statements for further information regarding the significant regulatory assets and liabilities of Exelon, ComEd and PECO.

For each regulatory jurisdiction where they conduct business, Exelon, ComEd and PECO continually assess whether the regulatory assets and liabilities continue to meet the criteria for probable future recovery or settlement. This assessment includes consideration of factors such as changes in applicable regulatory environments, recent rate orders to other regulated entities in the same jurisdiction, the status of any pending or potential deregulation legislation and the ability to recover costs through regulated rates.

The electric businesses of both ComEd and PECO are currently subject to rate freezes or rate caps that limit the opportunity to recover increased costs and the costs of new investment in facilities through rates during the rate freeze or rate cap period. Because the current rates include the recovery and settlement of existing regulatory assets and liabilities, respectively, and rates in effect during the rate freeze or rate cap periods are expected to allow Exelon, ComEd and PECO to earn a reasonable rate of return during that period, management believes the existing regulatory assets and liabilities are probable of recovery. This determination reflects the current political and regulatory climate at the Federal level and in the states where ComEd and PECO do business but is subject to change in the future. If future recovery of costs ceases to be probable, the regulatory assets and liabilities would be written-off and recognized in current period earnings. A write-off of regulatory assets could limit the ability of ComEd and PECO to pay dividends under Federal and state law.

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

The Registrants enter into derivatives to manage their exposure to fluctuations in interest rates, changes in interest rates related to planned future debt issuances and changes in the fair value of outstanding debt. Generation utilizes derivatives with respect to energy transactions to manage the utilization of its available generating capability and provisions of wholesale energy to its affiliates. Generation also utilizes energy option contracts and energy financial swap arrangements to limit the market price risk associated with forward energy commodity contracts. Additionally, Generation enters into energy-related derivatives for trading purposes. All of the Registrant's derivative activities are in accordance with Exelon's Risk Management Policy (RMP).

The Registrants account for derivative financial instruments under SFAS No. 133, “Accounting for Derivatives and Hedging Activities” (SFAS No. 133). Under the provisions of SFAS No. 133, all derivatives are recognized on the balance sheet at their fair value unless they qualify for a normal purchases or normal sales exception. Derivatives recorded at fair value on the balance sheet are presented as current or noncurrent mark-to-market derivative assets or liabilities. Changes in the derivatives recorded at fair value are recognized in earnings unless specific hedge accounting criteria are met, in which case those changes are recorded in earnings as an offset to the changes in fair value of the exposure being hedged or deferred in accumulated other comprehensive income and recognized in earnings when the hedged transaction occurs.

Normal Purchases and Normal Sales Exception. The availability of the normal purchases and normal sales exception is based upon the assessment of the ability and intent to deliver or take delivery of the underlying item. This assessment is based primarily on internal models that forecast customer demand for electricity and gas supply. These models include assumptions regarding customer load growth rates, which are influenced by the economy, weather and the impact of customer choice, and generating unit availability, particularly nuclear generating unit capability factors. If it was determined that a transaction designated as a “normal” purchases or a “normal” sale no longer met the scope exceptions, the fair value of the related contract would be recorded on the balance sheet and immediately recognized through earnings.

Energy Contracts. Identification of an energy contract as a qualifying cash-flow hedge requires Generation to determine that the contract is in accordance with the RMP, the forecasted future transaction is probable, and the hedging relationship between the energy contract and the expected future purchase or sale of energy is expected to be highly effective at the initiation of the hedge and throughout the hedging relationship. Internal models that measure the statistical correlation between the derivative and the associated hedged item determine the effectiveness of such an energy contract designated as a hedge. Generation reassesses its cash-flow hedges on a regular basis to determine if they continue to be effective and that the forecasted future transactions are probable. When a contract does not meet the effective or probable criteria of SFAS No. 133, hedge accounting is discontinued and changes in the fair value of the derivative are recorded through earnings.

As a part of accounting for derivatives, the Registrants make estimates and assumptions concerning future commodity prices, load requirements, interest rates, the timing of future transactions and their probable cash flows, the fair value of contracts and the expected changes in the fair value in deciding whether or not to enter into derivative transactions, and in determining the initial accounting treatment for derivative transactions. Generation uses quoted exchange prices to the extent they are available or external broker quotes in order to determine the fair value of energy contracts. When external prices are not available, Generation uses internal models to determine the fair value. These internal models include assumptions of the future prices of energy based on the specific market in which the energy is being purchased, using externally available forward market pricing curves for all periods possible under the pricing model. Generation uses the Black model, a standard industry valuation model, to determine the fair value of energy derivative contracts that are marked-to-market.

Interest-Rate Derivative Instruments. To determine the fair value of interest-rate swap agreements, the Registrants use external dealer prices or internal valuation models that utilize assumptions of available market pricing curves.

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

In the preparation of their financial statements, the Registrants make judgments regarding the future outcome of contingent events and record loss contingency amounts that are probable and reasonably estimated based upon available information. The amounts recorded may differ from the actual income or expense that occurs when the uncertainty is resolved. The estimates that the

Registrants make in accounting for contingencies and the gains and losses that they record upon the ultimate resolution of these uncertainties have a significant effect on the liabilities and expenses in their financial statements.

Taxation

The Registrants are required to make judgments regarding the potential tax effects of various financial transactions and results of operations in order to estimate their obligations to taxing authorities. These tax obligations include income, real estate, sales and use and employment-related taxes and ongoing appeals related to these tax matters. These judgments include reserves for potential adverse outcomes regarding tax positions that have been taken. The Registrants also estimate their ability to utilize tax attributes, including those in the form of carryforwards for which the benefits have already been reflected in the financial statements. Other than as noted below, the Registrants do not record valuation allowances for deferred tax assets related to capital losses that the Registrants believe will be realized in future periods. While the Registrants believe the resulting tax reserve balances as of December 31, 2005 reflect the probable expected outcome of pending tax matters in accordance with SFAS No. 5, “Accounting for Contingencies,” and SFAS No. 109, “Accounting for Income Taxes,” the ultimate outcome of such matters could result in favorable or unfavorable adjustments to their consolidated financial statements and such adjustments could be material.

Environmental Costs

As of December 31, 2005, Exelon, ComEd, PECO and Generation had accrued liabilities of $128 million, $54 million, $47 million and $27 million, respectively, for environmental investigation and remediation costs. These liabilities are based upon estimates with respect to the number of sites for which the Registrants will be responsible, the scope and cost of work to be performed at each site, the portion of costs that will be shared with other parties and the timing of the remediation work. Where timing and costs of expenditures can be reliably estimated, amounts are discounted. These amounts represent $89 million, $48 million, and $41 million of the total accrued for Exelon, ComEd, and PECO, respectively. Generation has no accrued environmental investigation and remediation costs recorded on a discounted basis. Where timing and amounts cannot be reliably estimated, amounts are recognized on an undiscounted basis. Such amounts represent $39 million, $6 million, $6 million and $27 million, respectively, of the total accrued liabilities for Exelon, ComEd, PECO and Generation. Estimates can be affected by the factors noted above as well as by changes in technology, regulations or the requirements of local governmental authorities.

Asbestos Personal Injury Claims

As of December 31, 2005, Exelon and Generation have approximately $50 million reserved in total for asbestos-related bodily injury claims. Approximately $9 million of this amount relates to 120 open claims presented to Generation as of December 31, 2005, while the remaining $41 million of the reserve is for estimated future asbestos-related bodily injury claims anticipated to arise through 2030 based on actuarial assumptions and analysis. Exelon’s and Generation’s management each determined that it was not reasonable to estimate future asbestos-related personal injury claims beyond 2030 based on the historical claims data available and the significant amount of judgment required to estimate this liability. In calculating the future losses, management and the actuaries made various assumptions, including but not limited to, the overall number of future claims estimated through the use of actuarial models, Exelon’s estimated portion of future settlements and obligations, the distribution of exposure sites, the anticipated future mix of diseases that related to asbestos exposure and the anticipated levels of awards made to plaintiffs. Exelon plans to obtain annual updates of the estimate of future losses. The amounts recorded by Generation for estimated future asbestos-related bodily injury claims are based upon historical experience and third-party actuarial studies. Projecting future events, such as the number of new claims to be filed each year, the average cost of disposing of claims, as well as the numerous uncertainties surrounding asbestos-related litigation and possible legislative measures in the United States, could cause the actual costs to be higher or lower than projected. Management cautions, however, that these estimates for asbestos-related bodily injury cases and settlements are difficult to predict and may be influenced by many factors. Accordingly, these matters, if resolved in a manner different from the estimate, could have a material effect on Exelon's or Generation's results of operations, financial position and cash flow.

Severance Accounting (Exelon, ComEd, PECO and Generation)

The Registrants provide severance benefits to terminated employees pursuant to pre-existing severance plans primarily based upon each individual employee's years of service with the Registrants and compensation level. The Registrants accrue severance benefits that are considered probable and can be reasonably estimated in accordance with SFAS No. 112, "Employer's Accounting for Postemployment Benefits, an amendment of FASB Statements No. 5 and 43" (SFAS No. 112). A significant assumption in estimating severance charges is the determination of the number of positions to be eliminated. The Registrants base their estimates on their current plans and ability to determine the appropriate staffing levels to effectively operate their businesses. Exelon, ComEd, PECO and Generation recorded severance charges (benefits) of $(14) million, $(9) million, $1 million and $(4) million, respectively, in 2005, and severance charges of $32 million, $10 million, $3 million and $2 million, respectively, in 2004, related to personnel reductions. The Registrants may incur further severance costs if they identify additional positions to be eliminated. These costs will be recorded in the period in which the costs can be reasonably estimated.

Revenue Recognition (Exelon, ComEd, PECO and Generation)

Revenues related to the sale of energy are recorded when service is rendered or energy is delivered to customers. The determination of ComEd's, PECO's and Exelon Energy's energy sales to individual customers, however, is based on systematic readings of customer meters generally on a monthly basis. At the end of each month, amounts of energy delivered to customers since the date of the last meter reading are estimated, and corresponding unbilled revenue is recorded. This unbilled revenue is estimated each month based on daily customer usage measured by generation or gas throughput volume, estimated customer usage by class, estimated losses of energy during delivery to customers and applicable customer rates. Customer accounts receivable of ComEd, PECO and Generation included estimates of $287 million, $175 million and $89 million, respectively, for unbilled revenue as of December 31, 2005 as a result of unread meters at ComEd, PECO and Exelon Energy. Increases in volumes delivered to the utilities' customers and favorable rate mix due to changes in usage patterns in customer classes in the period could be significant to the calculation of unbilled revenue. Changes in the timing of meter reading schedules and the number and type of customers scheduled for each meter reading date would also have an effect on the estimated unbilled revenue; however, total operating revenues would remain materially unchanged.

The determination of Generation's energy sales, excluding Exelon Energy's, is based on estimated amounts delivered as well as fixed quantity sales. At the end of each month, amounts of energy delivered to customers during the month are estimated and the corresponding unbilled revenue is recorded. Customer accounts receivable of Exelon and Generation as of December 31, 2005 include unbilled energy revenues of $435 million related to unbilled energy sales of Generation. Increases in volumes delivered to the wholesale customers in the period, as well as price, would increase unbilled revenue.

Generation's revenue from service agreements, such as the nuclear Operating Service Agreement with PSEG Nuclear, is dependent upon when the services are rendered. Service agreements representing a cost recovery arrangement are presented gross within revenues for the amounts due from the party receiving the service, and the costs associated with providing the service are presented within operating and maintenance expenses.

Results of Operations (Dollars in millions except for per share data, unless otherwise noted)

Year Ended December 31, 2005 Compared to Year Ended December 31, 2004

Significant Operating Trends—Exelon

Exelon Corporation	2005	2004	Favorable (unfavorable) variance
Operating revenues	$15,357	$14,133	$ 1,224
Purchased power and fuel expense	5,646	4,929	(717)
Operating and maintenance expense	3,718	3,700	(18)
Impairment of goodwill	1,207	—	(1,207)
Depreciation and amortization	1,334	1,295	(39)
Operating income	2,724	3,499	(775)
Other income and deductions	(829)	(922)	93
Income from continuing operations before income taxes and minority interest	1,895	2,577	(682)
Income taxes	944	713	(231)
Income from continuing operations	951	1,870	(919)
Income (loss) from discontinued operations, net of income taxes	14	(29)	43
Income before cumulative effect of a change in accounting principle	965	1,841	(876)
Cumulative effect of changes in accounting principles	(42)	23	(65)
Net income	923	1,864	(941)
Diluted earnings per share	$ 1.36	$ 2.78	$ (1.42)

Net Income. Net income for 2005 reflects an impairment charge of $1,207 million associated with ComEd's goodwill and losses of $42 million for the cumulative effect of adopting FIN 47, partially offset by higher realized prices on market sales at Generation and favorable weather conditions in the ComEd and PECO service territories. Net income for 2004 reflects income of $32 million for the adoption of FIN 46-R, partially offset by a loss of $9 million related to the adoption of Emerging Issues Task Force (EITF) Issue No. 03-16, "Accounting for Investments in Limited Liability Companies" (EITF 03-16). See Note 1 of Exelon's Notes to Consolidated Financial Statements for further information regarding the adoption of FIN 46-R.

Operating Revenues. Operating revenues increased primarily due to increased revenues at ComEd and PECO and increased revenues from non-affiliates at Generation. The increase in revenues at ComEd and PECO was primarily due to favorable weather conditions, an increase in the number of customers choosing ComEd or PECO as their electric supplier and higher transmission revenues, partially offset by decreased CTC collections at ComEd. The increase in revenues from non-affiliates at Generation was primarily due to higher prices on energy sold in the market, partially offset by an increase in the percentage of energy produced and sold to ComEd and PECO and the sale of Boston Generating in 2004. See further analysis and discussion of operating revenues by segment below.

Purchased Power and Fuel Expense. Purchased power and fuel expense increased primarily due to overall higher market energy prices and higher natural gas and oil prices, partially offset by the decrease in fuel expense due to the sale of Boston Generating in 2004, favorable mark-to-market adjustments related to non-trading activities and the expiration of the purchase power agreement with Midwest Generation in 2004. Purchased power represented 22% of Generation's total supply in 2005 compared to 24% in 2004. See further analysis and discussion of purchased power and fuel expense by segment below.

Operating and Maintenance Expense. Operating and maintenance expense increased primarily due to a gain recorded in 2004 related to the DOE Settlement, an increase to the reserve for the estimated future asbestos-related bodily injury claims that was recorded in 2005, higher costs associated with planned nuclear refueling outages, and increased costs related to an operating agreement with a subsidiary of Tamuin International, Inc. (formerly Sithe International, Inc.), partially offset by the sale of Boston Generating in 2004 and decreased severance and benefit expense. See further discussion of operating and maintenance expenses by segment below.

Impairment of Goodwill. ComEd recorded a $1,207 million charge during 2005 to impair its goodwill.

Depreciation and Amortization Expense. The increase in depreciation and amortization expense was primarily due to additional plant placed in service, additional amortization of the CTC at PECO and accelerated amortization of PECO's current customer information and billing system, partially offset by the establishment of an ARC asset for retired nuclear units in 2004 which was immediately impaired through depreciation expense.

Operating Income. Exclusive of the changes in operating revenues, purchased power and fuel expense, operating and maintenance expense, impairment of goodwill and depreciation and amortization expense discussed above, the change in operating income was the result of increased taxes other than income, partially offset by the sale of Boston Generating in 2004 and reduced property tax expense.

Other Income and Deductions. The change in other income and deductions reflects a 2004 charge at ComEd associated with the accelerated retirement of debt and the related reduction in interest expense from these debt retirements and increased realized gains related to the decommissioning trust fund investments for the AmerGen plants, partially offset by increased interest expense on short-term debt at Exelon, increased losses from Exelon's investment in synthetic fuel-producing facilities and an $85 million gain recorded in 2004 on the sale of Boston Generating.

Effective Income Tax Rate. The effective income tax rate from continuing operations was 50% for 2005 compared to 28% for 2004. Exclusive of the goodwill impairment charge, the effective income tax rate for 2005 was 30%. See Note 12 of Exelon's Notes to the Consolidated Financial Statements for further discussion of the change in the effective income tax rate.

Discontinued Operations. On January 31, 2005, subsidiaries of Generation completed a series of transactions that resulted in Generation's sale of its investment in Sithe. In addition, Exelon has sold or wound down substantially all components of Enterprises and AllEnergy, a business within Exelon Energy. Accordingly, the results of operations and any gain or loss on the sale of these entities have been presented as discontinued operations within Exelon's and Generation's Consolidated Statements of Income. See Notes 2 and 3 of Exelon's Notes to Consolidated Financial Statements for further information regarding the presentation of Sithe, certain Enterprises businesses and AllEnergy as discontinued operations and the sale of Sithe. The results of Sithe and AllEnergy are included in the Generation discussion below.

The income from discontinued operations increased by $43 million from 2004 to 2005 primarily due to the gain on the sale of Sithe in the first quarter of 2005.

Cumulative Effect of Changes in Accounting Principles. The cumulative effect of changes in accounting principles reflects the impact of adopting FIN 47 as of December 31, 2005 and the consolidation of Sithe in accordance with FIN 46-R as of March 31, 2004. See Notes 1 and 14 of Exelon's Notes to Consolidated Financial Statements for further discussion of the consolidation of Sithe and the adoption of FIN 47, respectively.

Results of Operations by Business Segment

The comparisons of 2005 and 2004 operating results and other statistical information set forth below include intercompany transactions, which are eliminated in Exelon's consolidated financial statements.

Net Income (Loss) from Continuing Operations by Business Segment

	2005	2004	Favorable (unfavorable) variance
ComEd	$ (676)	$ 676	$(1,352)
PECO	520	455	65
Generation	1,109	657	452
Other [(a)]	(2)	82	(84)
Total	$ 951	$1,870	$ (919)

(a) Other includes corporate operations, shared service entities, including BSC, Enterprises, investments in synthetic fuel-producing facilities and intersegment eliminations.

Income (Loss) Before Cumulative Effect of Changes in Accounting Principles by Business Segment

	2005	2004	Favorable (unfavorable) variance
ComEd	$ (676)	$ 676	$(1,352)
PECO	520	455	65
Generation	1,128	641	487
Other [(a)]	(7)	69	(76)
Total	$ 965	$1,841	$ (876)

(a) Other includes corporate operations, shared service entities, including BSC, Enterprises, investments in synthetic fuel-producing facilities and intersegment eliminations.

Net Income (Loss) by Business Segment

	2005	2004	Favorable (unfavorable) variance
ComEd	$ (685)	$ 676	$(1,361)
PECO	517	455	62
Generation	1,098	673	425
Other [(a)]	(7)	60	(67)
Total	$ 923	$1,864	$ (941)

(a) Other includes corporate operations, shared service entities, including BSC, Enterprises, investments in synthetic fuel-producing facilities and intersegment eliminations.

Results of Operations–ComEd

	2005	2004	Favorable (unfavorable) variance
Operating revenues	$6,264	$5,803	$ 461
Operating expenses			
Purchased power	3,520	2,588	(932)
Operating and maintenance	833	897	64
Impairment of goodwill	1,207	—	(1,207)
Depreciation and amortization	413	410	(3)
Taxes other than income	303	291	(12)
Total operating expense	6,276	4,186	(2,090)
Operating income (loss)	(12)	1,617	(1,629)
Other income and deductions			
Interest expense	(295)	(369)	74
Equity in losses of unconsolidated affiliates	(14)	(19)	5
Net loss on extinguishment of long-term debt	—	(130)	130
Other, net	8	34	(26)
Total other income and deductions	(301)	(484)	183
Income (loss) before income taxes and cumulative effect of a change in accounting principle	(313)	1,133	(1,446)
Income taxes	363	457	94
Income (loss) before cumulative effect of a change in accounting principles	(676)	676	(1,352)
Cumulative effect of change in accounting principle	(9)	—	(9)
Net income (loss)	$ (685)	$ 676	$(1,361)

Net Loss. ComEd's net loss in 2005 was driven by the impairment of goodwill and higher purchased power expense, partially offset by higher operating revenues due to favorable weather and due to the impacts of a 2004 charge associated with the accelerated retirement of long-term debt and lower interest expense.

Operating Revenues. The changes in operating revenues for 2005 compared to 2004 consisted of the following:

	Increase (decrease)
Weather	$415
Customer choice	81
Rate changes and mix	(66)
Volume	(3)
Other	(9)
Retail revenue	418
PJM transmission	58
T&O / SECA rates	(28)
Other	13
Wholesale and miscellaneous revenues	43
Increase in operating revenues	$461

Weather. Revenues were higher by $415 million due to favorable weather conditions in 2005 compared to 2004. The demand for electricity is affected by weather conditions. Very warm weather in summer months and very cold weather in other months are referred to as “favorable weather conditions” because these weather conditions result in increased sales of electricity. Conversely, mild weather in non-summer months reduces demand. In ComEd’s service territory, cooling and heating degree days were 90% and 1% higher, respectively, than the prior year.

Customer choice. For 2005 and 2004, 33% and 35% of energy delivered to ComEd’s retail customers was provided by alternative electric suppliers or under the Power Purchase Option (PPO).

All ComEd customers have the choice to purchase energy from an alternative electric supplier. This choice does not impact the volume of deliveries, but affects revenue collected from customers related to supplied energy and generation service. As of December 31, 2005, one alternative supplier was approved to serve residential customers in the ComEd service territory. However, no residential customers have selected this alternative supplier.

	2005	2004
Retail customers purchasing energy from an alternative electric supplier:		
Volume (GWhs) [(a)]	19,310	20,939
Percentage of total retail deliveries	21%	24%
Retail customers purchasing energy from an alternative electric supplier or the ComEd PPO:		
Number of customers at period end	21,276	22,161
Percentage of total retail customers	[(b)]	[(b)]
Volume (GWhs) [(a)]	30,905	30,426
Percentage of total retail deliveries	33%	35%

(a) One GWh is the equivalent of one million kilowatthours (kWh).
(b) Less than one percent.

Rate changes and mix. The change is primarily due to the increased wholesale market price of electricity and other adjustments to the energy component of the CTC calculation which resulted in a decrease of $64 million to $105 million in 2005 as compared to 2004. As a result of increasing mitigation factors and changes in energy prices, ComEd anticipates that CTC revenues will range from $35 million to $50 million in 2006. Under current Illinois law, no CTCs will be collected after 2006.

PJM transmission. ComEd’s transmission revenues increased by $58 million in 2005 due to ComEd’s May 1, 2004 entry into PJM.

T&O / SECA rates. Revenues decreased $28 million as a result of the elimination of T&O rates in accordance with FERC orders that became effective December 1, 2004. Effective December 1, 2004, PJM became obligated to pay SECA collections to ComEd, and ComEd became obligated to pay SECA charges—see “Purchased Power Expense” below. See Note 4 of Exelon’s Notes to Consolidated Financial Statements for more information on T&O / SECA rates.

Purchased Power Expense. The changes in purchased power expense for 2005 compared to 2004 consisted of the following:

	Increase (decrease)
Prices	$606
Weather	200
Customer choice	65
PJM	63
Volume	7
T&O collections / SECA rates	(15)
Other	6
Increase in purchased power expense	$932

Prices. Purchased power increased due to higher prices associated with ComEd's PPA with Generation of $497 million, and ancillary services of $109 million from PJM. In 2000, ComEd and Generation entered into a PPA that fixed the pricing for purchased power through December 31, 2004 based upon the then current market prices. As a result of the Amended and Restated Purchase Power Agreement as of April 30, 2004 with Generation, starting in January 1, 2005, ComEd began paying higher prices for its purchased power from Generation and ceased to procure its ancillary services from Generation. This agreement fixed the pricing for purchased power through December 31, 2006 based upon the current market prices as of April 30, 2004.

Weather. The $200 million increase in purchased power expense attributable to weather was due to favorable weather conditions in the ComEd service territory, which increased the amount of electricity sold.

Customer choice. The $65 million increase in purchased power expense from customer choice was primarily due to fewer ComEd non-residential customers electing to purchase energy from an alternative electric supplier.

PJM. The $63 million increase reflects higher transmission and purchased power expense of $57 million due to ComEd's May 1, 2004 entry into PJM and PJM administrative fees that increased by $6 million over 2004 fees.

T&O Collections / SECA rates. Prior to FERC orders issued in November 2004, ComEd collected T&O rates for transmission service scheduled out of or across ComEd's transmission system. Rates collected as the transmission owner were recorded in operating revenues. After joining PJM on May 1, 2004, PJM allocated T&O collections to ComEd as a load-serving entity. The collections received by ComEd as a load-serving entity were recorded as a decrease to purchased power expense. ComEd's purchased power expense increased $14 million due to ComEd no longer collecting T&O revenues in 2005.

Effective December 1, 2004, PJM became obligated to pay SECA collections to ComEd and ComEd became obligated to pay SECA charges. During 2005, ComEd recorded SECA collections net of SECA charges of $29 million. See Note 4 of Exelon's Notes to Consolidated Financial Statements for more information on T&O /SECA rates.

Operating and Maintenance Expense. The changes in operating and maintenance expense for 2005 compared to 2004 consisted of the following:

	Increase (decrease)
Severance-related expenses [(a)]	$(47)
Employee fringe benefits [(b)]	(18)
Pension expense and deferred compensation [(c)]	(15)
Allowance for uncollectible accounts	(13)
Injuries and damages	(2)
Corporate allocations [(b)]	15
Storm costs	14
Contractors	12
PSEG merger integration costs	8
Other	(18)
Decrease in operating and maintenance expense	$(64)

(a) Consists of salary continuance severance costs, curtailment charges for pension and other postretirement benefits, and special termination benefit charges related to other postretirement benefits. The decrease reflects reduced severance-related activity in 2005 as compared to 2004.
(b) Excludes severance-related expenses and pension expense. Reflects fewer employees compared to prior year and a reduction in 2005 related to estimated medical plan fees. A portion of the employee reduction is offset by an increase in corporate allocations.
(c) Pension expense in 2005 is lower than in 2004 due in large part to significant pension plan contributions made in the first quarter of 2005. See Note 15 of Exelon's Notes to Consolidated Financial Statements for additional information.

Impairment of Goodwill. During the fourth quarter of 2005, ComEd completed the annually required assessment of goodwill for impairment purposes. The assessment compares the carrying value of goodwill to the estimated fair value of goodwill as of a point in time (November 1). The estimated fair value incorporates management's assessment of current events and expected future cash flows. The 2005 test indicated that ComEd's goodwill was impaired and a charge of $1.2 billion was recorded. The 2005 impairment was driven by changes in the fair value of ComEd's purchase power agreement with Generation, the upcoming end of ComEd's transition period and related transition revenues, regulatory uncertainty in Illinois as of November 1, 2005, anticipated increases in capital expenditures in future years and decreases in market valuations of comparable companies that are utilized to estimate the fair value of ComEd. After reflecting the impairment, ComEd has approximately $3.5 billion of remaining goodwill as of December 31, 2005.

Depreciation and Amortization Expense. The changes in depreciation and amortization expense for 2005 compared to 2004 consisted of the following:

	Increase (decrease)
Depreciation expense	$ 17
Other amortization expense	(14)
Increase in depreciation and amortization expense	$ 3

The increase in depreciation expense is primarily due to capital additions.

The decrease in other amortization expense was primarily due to completing the amortization of one of ComEd's software packages in 2004.

Taxes Other Than Income. The changes in taxes other than income for 2005 compared to 2004 consisted of the following:

	Increase (decrease)
Taxes on utility revenues [(a)]	$13
Tax refund [(b)]	6
Other	(7)
Increase in taxes other than income	$12

(a) As these taxes were collected from customers and remitted to the taxing authorities and included in revenues and expenses, the increase in expense was offset by a corresponding increase in revenues.
(b) During 2004, a refund was received for Illinois electricity distribution taxes.

Interest Expense. The reduction in interest expense of $74 million for 2005 compared to 2004 was primarily due to long-term debt retirements and prepayments in 2004 pursuant to Exelon's accelerated liability management plan and scheduled payments on long-term debt owed to the ComEd Funding Trust.

Equity in Losses of Unconsolidated Affiliates. The decrease in equity in losses of unconsolidated affiliates was a result of a decrease in interest expense of the deconsolidated financing trusts due to scheduled repayments of outstanding long-term debt.

Net Loss on Extinguishment of Long-Term Debt. In 2004, Exelon initiated an accelerated liability management plan at ComEd that resulted in the retirement of approximately $768 million of long-term debt, of which $618 million was retired during the third quarter of 2004. During 2004, ComEd recorded a charge of $130 million associated with the retirement of debt under the plan. The components of this charge included the following: $86 million related to prepayment premiums; $12 million related to net unamortized premiums, discounts and debt issuance costs; $24 million of losses on reacquired debt previously deferred as regulatory assets; and $12 million related to settled cash-flow interest-rate swaps previously deferred as regulatory assets partially offset by $4 million of unamortized gain on settled fair value interest-rate swaps.

Other, Net. The changes in other, net for 2005 compared to 2004 consisted of the following:

	Increase (decrease)
Loss on settlement of cash-flow swaps [(a)]	$(15)
Interest income on long-term receivable from UII, LLC [(b)]	(16)
Other	5
Decrease in other, net	$(26)

(a) See Note 16 of Exelon's Notes to Consolidated Financial Statements for further information.
(b) The decrease in interest income on the long-term receivable from UII, LLC resulted from this receivable being repaid in late 2004.

Income Taxes. The effective income tax rate was (116.0)% and 40.3% for 2005 and 2004, respectively. Exclusive of the goodwill impairment charge, the effective rate for 2005 was 40.6%. See Note 10 of ComEd's Notes to Consolidated Financial Statements in Exelon's 2005 Form 10-K for further details of the components of the effective income tax rates.

Cumulative Effect of a Change in Accounting Principle. The cumulative effect of a change in accounting principle reflects the impact of adopting FIN 47 as of December 31, 2005. See Note 12 of ComEd's Notes to Consolidated Financial Statements in Exelon's 2005 Form 10-K for further discussion of the adoption of FIN 47.

Electric Operating Statistics and Revenue Detail

Retail Deliveries—(in GWhs)	2005	2004	Variance	% Change
Full service [(a)]				
Residential	30,042	26,463	3,579	13.5%
Small commercial & industrial	21,378	21,662	(284)	(1.3%)
Large commercial & industrial	7,904	6,913	991	14.3%
Public authorities & electric railroads	2,133	1,893	240	12.7%
Total full service	61,457	56,931	4,526	7.9%
PPO				
Small commercial & industrial	5,591	4,110	1,481	36.0%
Large commercial & industrial	6,004	5,377	627	11.7%
	11,595	9,487	2,108	22.2%
Delivery only [(b)]				
Small commercial & industrial	5,677	6,305	(628)	(10.0%)
Large commercial & industrial	13,633	14,634	(1,001)	(6.8%)
	19,310	20,939	(1,629)	(7.8%)
Total PPO and delivery only	30,905	30,426	479	1.6%
Total retail deliveries	92,362	87,357	5,005	5.7%

(a) Full service reflects deliveries to customers taking electric service under tariffed rates.
(b) Delivery only service reflects customers electing to receive generation service from an alternative electric supplier.

Electric Revenue	2005	2004	Variance	% Change
Full service [a]				
Residential	$2,584	$2,295	$289	12.6%
Small commercial & industrial	1,671	1,649	22	1.3%
Large commercial & industrial	408	380	28	7.4%
Public authorities & electric railroads	132	126	6	4.8%
Total full service	4,795	4,450	345	7.8%
PPO [b]				
Small commercial & industrial	385	274	111	40.5%
Large commercial & industrial	345	304	41	13.5%
	730	578	152	26.3%
Delivery only [c]				
Small commercial & industrial	95	128	(33)	(25.8%)
Large commercial & industrial	156	204	(48)	(23.5%)
	251	332	(81)	(24.4%)
Total PPO and delivery only	981	910	71	7.8%
Total electric retail revenues	5,776	5,360	416	7.8%
Wholesale and miscellaneous revenue [d]	488	443	45	10.2%
Total operating revenues	$6,264	$5,803	$461	7.9%

(a) Full service revenue reflects deliveries to customers taking electric service under tariffed rates, which include the cost of energy and the cost of the transmission and the distribution of the energy.

(b) Revenues from customers choosing the PPO include an energy charge at market rates, transmission and distribution charges, and a CTC.

(c) Delivery only revenues reflect revenue under tariff rates from customers electing to receive generation service from an alternative electric supplier, which includes a distribution charge and a CTC. Prior to ComEd's full integration into PJM on May 1, 2004, ComEd's transmission charges received from alternative electric suppliers were included in wholesale and miscellaneous revenue.

(d) Wholesale and miscellaneous revenues include transmission revenue (including revenue from PJM), sales to municipalities and other wholesale energy sales.

Results of Operations—PECO

	2005	2004	Favorable (unfavorable) variance
Operating revenues	$4,910	$4,487	$ 423
Operating expenses			
Purchased power	2,515	2,172	(343)
Operating and maintenance	549	547	(2)
Depreciation and amortization	566	518	(48)
Taxes other than income	231	236	5
Total operating expense	3,861	3,473	(388)
Operating income	1,049	1,014	35
Other income and deductions			
Interest expense	(280)	(303)	23
Equity in losses of unconsolidated affiliates	(16)	(25)	9
Other, net	14	18	(4)
Total other income and deductions	(282)	(310)	28
Income before income taxes and cumulative effect of a change in accounting principle	767	704	63
Income taxes	247	249	2
Income before cumulative effect of a change in accounting principle	520	455	65
Cumulative effect of a change in accounting principle	(3)	—	(3)
Net income	517	455	62
Preferred stock dividends	4	3	(1)
Net income on common stock	$ 513	$ 452	$ 61

Net Income. PECO's net income in 2005 increased primarily as a result of higher revenues, net of related purchased power expense, due to favorable weather and lower interest expense due to the scheduled retirement of debt owed to PETT, partially offset by higher CTC amortization.

Operating Revenues. The changes in PECO's operating revenues for 2005 compared to 2004 consisted of the following:

	Electric	Gas	Total increase (decrease)
Rate changes and mix	$ 72	$ 90	$162
Customer choice	118	—	118
Volume	101	(21)	80
Weather	54	10	64
Retail revenue	345	79	424
T&O / SECA rates	3	—	3
PJM transmission	(3)	—	(3)
Other	9	(10)	(1)
Wholesale and miscellaneous revenues	9	(10)	(1)
Increase in operating revenues	$354	$ 69	$423

Rate changes and mix. The increase in electric revenues at PECO attributable to rate changes and mix resulted from increased residential sales, which are billed at higher average rates relative to other customer classes. In addition, rates were higher in 2005 for certain large commercial and industrial customers whose rates reflect wholesale energy prices, which were higher in 2005 relative to 2004.

The increase in gas revenues was due to increases in rates through PAPUC-approved changes to the purchased gas adjustment clause that became effective March 1, 2004, March 1, 2005, June 1, 2005, September 1, 2005 and December 1, 2005. The average purchased gas cost rate per million cubic feet in effect for 2005 was 12% higher than the average rate for 2004.

Customer choice. For 2005 and 2004, 5% and 12%, respectively, of energy delivered to PECO's retail customers was provided by alternative electric suppliers.

All PECO customers have the choice to purchase energy from an alternative electric supplier. This choice does not impact the volume of deliveries, but affects revenue collected from customers related to supplied energy and generation service. Operating income is not affected by customer choice since any increase or decrease in revenues is completely offset by any related increase or decrease in purchased power expense.

	2005	2004
Retail customers purchasing energy from an alternative electric supplier:		
Number of customers at period end	44,500	101,500
Percentage of total retail customers	3%	7%
Volume (GWhs) [(a)]	2,094	4,605
Percentage of total retail deliveries	5%	12%

(a) One GWh is the equivalent of one million kilowatthours (kWh).

The increase in electric retail revenue associated with customer choice was primarily related to a significant number of residential customers returning to PECO as their energy provider in December 2004. This action followed the assignment of approximately 194,000 residential customers to alternative electric suppliers for a one-year term beginning in December 2003, as required by the PAPUC and PECO's final electric restructuring order. In 2005, additional customers returned to PECO as their energy supplier primarily as a result of two alternative energy suppliers exiting the market.

Volume. The increase in electric revenues was primarily as a result of higher delivery volume, exclusive of the effects of weather and customer choice, due to an increased number of customers and increased usage per customer across all customer classes. The decrease in gas revenues attributable to lower delivery volume, exclusive of the effects of weather, was primarily due to decreased customer usage, which is consistent with rising gas prices.

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 other months are referred to as "favorable weather conditions" because these weather conditions result in increased sales of electricity and gas. Conversely, mild weather reduces demand. Revenues were positively affected by favorable weather conditions at PECO in 2005 compared to 2004. In the PECO service territory, cooling and heating degree days were 21% and 2% higher, respectively, than the prior year.

T&O / SECA rates. Effective December 1, 2004, PJM became obligated to pay SECA collections to PECO, and PECO became obligated to pay SECA charges—see "Purchased Power and Fuel Expense" below. The elimination of T&O revenues and inclusion of SECA revenues had a minimal impact on PECO as T&O revenues recognized in the past were not material and SECA revenues currently being recognized also are not material. See Note 4 of Exelon's Notes to Consolidated Financial Statements for more information on T&O / SECA rates.

Other wholesale and miscellaneous revenues. Electric revenues increased $9 million primarily due to increased wholesale sales, and gas revenues decreased $10 million primarily due to decreased off-system sales.

Purchased Power and Fuel Expense. The changes in PECO's purchased power and fuel expense for 2005 compared to 2004 consisted of the following:

	Electric	Gas	Total increase (decrease)
Prices	$ 83	$ 90	$173
Customer choice	118	—	118
Weather	21	7	28
Volume	32	(15)	17
PJM transmission	11	—	11
SECA rates	9	—	9
Other	—	(13)	(13)
Increase in purchased power and fuel expense	$274	$ 69	$343

Prices. PECO's purchased power expense increased due to a change in the mix of average pricing related to its PPA with Generation. Fuel expense for gas increased due to higher gas prices. See "Operating Revenues" above.

Customer choice. The increase in purchased power expense from customer choice was primarily due to a significant number of residential customers returning to PECO as their energy provider in December 2004.

Weather. The increase in purchased power and fuel expense attributable to weather was primarily due to serving the increased demand due to favorable weather conditions in the PECO service territory.

Volume. The increase in purchased power expense attributable to volume, exclusive of the effects of weather and customer choice, was due primarily to an increased number of customers and increased usage per customer across all customer classes. The decrease in gas fuel expense attributable to volume, exclusive of the effects of weather, was due to decreased customer usage, which is consistent with rising gas prices.

SECA rates. Effective December 1, 2004, PJM became obligated to pay SECA collections to PECO, and PECO became obligated to pay SECA charges. During 2005 and 2004, PECO recorded SECA charges of $10 million and $1 million, respectively. See Note 4 of Exelon's Notes to Consolidated Financial Statements for more information on T&O /SECA rates.

Other. The decrease in gas fuel expense of $13 million was associated with decreased off-system sales.

Operating and Maintenance Expense. The changes in operating and maintenance expense for the 2005 compared to 2004 consisted of the following:

	Increase (decrease)
Contractors [(a)]	$ 8
Storm costs	7
Implementation of new customer information and billing system	4
PSEG merger integration costs	2
Severance-related expenses [(b)]	(14)
Injuries and damages	(6)
Other	1
Increase in operating and maintenance expense	$ 2

(a) The increase was primarily due to increases in vegetation management services compared to the prior year at PECO.
(b) Consists of salary continuance severance costs, curtailment charges for pension and other post retirement benefits, and special termination benefit charges related to other postretirement benefits. The decrease reflects reduced severance-related activity in 2005 compared to 2004.

Depreciation and Amortization Expense. The changes in depreciation and amortization expense for 2005 compared to 2004 consisted of the following:

	Increase (decrease)
Competitive transition charge amortization	$37
Accelerated amortization of PECO billing system	13
Depreciation expense	3
Other amortization expense	(5)
Increase in depreciation and amortization expense	$48

PECO's additional amortization of the CTC is in accordance with its original settlement under the Pennsylvania Competition Act.

In January 2005, as part of a broader systems strategy at PECO associated with the pending merger with PSEG, Exelon's Board of Directors approved the implementation of a new customer information and billing system at PECO. The approval of this new system requires the accelerated amortization of PECO's current system through 2006 and the recognition of additional amortization expense of $13 million and $10 million in 2005 and 2006, respectively. If additional system changes are approved, additional accelerated depreciation may be required.

The increase in depreciation expense is primarily due to capital additions.

Taxes Other Than Income. The changes in taxes other than income for 2005 compared to 2004 consisted of the following:

	Increase (decrease)
Reduction in capital stock tax accrual in 2005 [(a)]	$(17)
Reduction in real estate tax accrual in 2005 [(b)]	(6)
Taxes on utility revenues [(c)]	24
Other	(6)
Decrease in taxes other than income	$ (5)

(a) Represents a reduction in 2005 of prior year capital stock tax accruals as a result of a favorable decision from the Pennsylvania Board of Finance and Revenue.
(b) Represents the reduction of a real estate tax accrual in March 2005 following settlements between PECO and various taxing authorities related to prior year tax assessments. See Note 20 of Exelon's Notes to the Financial Statements for additional information.
(c) As these taxes were collected from customers and remitted to the taxing authorities and included in revenues and expenses, the increase in tax expense was offset by a corresponding increase in revenues.

Interest Expense. The reduction in interest expense at PECO of $23 million for 2005 compared to 2004 was primarily due to scheduled payments on long-term debt owed to PETT.

Equity in Losses of Unconsolidated Affiliates. The decrease in equity in losses of unconsolidated affiliates was a result of a decrease in interest expense of the deconsolidated financing trusts of PECO due to scheduled repayments of outstanding long-term debt.

Income Taxes. PECO's effective income tax rate was 32.2% for 2005 compared to 35.4% for 2004. The decrease in the effective tax rate was primarily attributable to a state income tax benefit recorded as a result of the favorable settlement of a 2000 Pennsylvania corporate net income tax audit. See Note 8 of PECO's Notes to Consolidated Financial Statements in Exelon's 2005 Form 10-K for further details of the components of the effective income tax rates.

Cumulative Effect of a Change in Accounting Principle. The cumulative effect of a change in accounting principle reflects the impact of adopting FIN 47 as of December 31, 2005. See Note 10 of PECO's Notes to Consolidated Financial Statements in Exelon's 2005 Form 10-K for further discussion of the adoption of FIN 47.

PECO Electric Operating Statistics and Revenue Detail

PECO's electric sales statistics and revenue detail are as follows:

Retail Deliveries—(in GWhs)	2005	2004	Variance	% Change
Full service [(a)]				
Residential	13,135	10,349	2,786	26.9%
Small commercial & industrial	7,263	6,728	535	8.0%
Large commercial & industrial	15,205	14,908	297	2.0%
Public authorities & electric railroads	962	914	48	5.3%
Total full service	36,565	32,899	3,666	11.1%
Delivery only [(b)]				
Residential	334	2,158	(1,824)	(84.5%)
Small commercial & industrial	1,257	1,687	(430)	(25.5%)
Large commercial & industrial	503	760	(257)	(33.8%)
Total delivery only	2,094	4,605	(2,511)	(54.5%)
Total retail deliveries	38,659	37,504	1,155	3.1%

(a) Full service reflects deliveries to customers taking electric service under tariffed rates.
(b) Delivery only service reflects customers receiving electric generation service from an alternative electric supplier.

Electric Revenue	2005	2004	Variance	% Change
Full service [a]				
Residential	$1,705	$1,317	$ 388	29.5%
Small commercial & industrial	818	756	62	8.2%
Large commercial & industrial	1,173	1,113	60	5.4%
Public authorities & electric railroads	84	80	4	5.0%
Total full service	3,780	3,266	514	15.7%
Delivery only [b]				
Residential	25	164	(139)	(84.8%)
Small commercial & industrial	63	86	(23)	(26.7%)
Large commercial & industrial	13	20	(7)	(35.0%)
Total delivery only	101	270	(169)	(62.6%)
Total electric retail revenues	3,881	3,536	345	9.8%
Miscellaneous revenue [c]	212	203	9	4.4%
Total electric and other revenue	$4,093	$3,739	$ 354	9.5%

(a) Full service revenue reflects revenue from customers taking electric service under tariffed rates, which includes the cost of energy, the cost of the transmission and the distribution of the energy and a CTC.
(b) Delivery only revenue reflects revenue from customers receiving generation service from an alternative electric supplier, which includes a distribution charge and a CTC.
(c) Miscellaneous revenues include transmission revenue from PJM and other wholesale energy sales.

PECO's Gas Sales Statistics and Revenue Detail

PECO's gas sales statistics and revenue detail were as follows:

Deliveries to customers (in million cubic feet (mmcf))	2005	2004	Variance	% Change
Retail sales	59,751	59,949	(198)	(0.3%)
Transportation	25,310	27,148	(1,838)	(6.8%)
Total	85,061	87,097	(2,036)	(2.3%)

Revenue	2005	2004	Variance	% Change
Retail sales	$ 783	$ 702	$ 81	11.5%
Transportation	16	18	(2)	(11.1%)
Resales and other	18	28	(10)	(35.7%)
Total gas revenue	$ 817	$ 748	$ 69	9.2%

Results of Operations—Generation

	2005	2004	Favorable (unfavorable) variance
Operating revenues	$9,046	$7,703	$1,343
Operating expenses			
Purchased power	2,569	2,307	(262)
Fuel	1,913	1,704	(209)
Operating and maintenance	2,288	2,201	(87)
Depreciation and amortization	254	286	32
Taxes other than income	170	166	(4)
Total operating expenses	7,194	6,664	(530)
Operating income	1,852	1,039	813
Other income and deductions			
Interest expense	(128)	(103)	(25)
Equity in losses of unconsolidated affiliates	(1)	(14)	13
Other, net	95	130	(35)
Total other income and deductions	(34)	13	(47)
Income from continuing operations before income taxes and minority interest	1,818	1,052	766
Income taxes	709	401	(308)
Income from continuing operations before minority interest	1,109	651	458
Minority interest	—	6	(6)
Income from continuing operations	1,109	657	452
Discontinued operations			
Loss from discontinued operations	—	(45)	45
Gain on disposal of discontinued operations	24	—	24
Income taxes	5	(29)	(34)
Income (loss) from discontinued operations	19	(16)	35
Income before cumulative effect of changes in accounting principles	1,128	641	487
Cumulative effect of changes in accounting principles	(30)	32	(62)
Net income	$1,098	$ 673	$ 425

Net Income. Generation's net income in 2005 increased $425 million as compared to the prior year, primarily as a result of higher revenue, net of purchased power and fuel expense, partially offset by higher operating and maintenance expense and interest expense. Generation's revenue, net of purchased power and fuel expense, increased $872 million in 2005 as compared to the prior year. This increase was driven by the contractual increase in prices associated with Generation's power sales agreement with ComEd and higher average margins on wholesale market sales as higher spot market prices more than compensated for higher fuel prices and the impact of higher nuclear generation.

Operating Revenues. For 2005 and 2004, Generation's sales were as follows:

Revenue	2005	2004	Variance	% Change
Electric sales to affiliates	$4,775	$3,749	$1,026	27.4%
Wholesale and retail electric sales	3,341	3,227	114	3.5%
Total energy sales revenue	8,116	6,976	1,140	16.3%
Retail gas sales	613	448	165	36.8%
Trading portfolio	17	—	17	n.m.
Other revenue (a)	300	279	21	7.5%
Total revenue	$9,046	$7,703	$1,343	17.4%

(a) Includes sales related to tolling agreements, fossil fuel sales and decommissioning revenue from ComEd and PECO.
n.m. Not meaningful

Sales (in GWhs)	2005	2004	Variance	% Change
Electric sales to affiliates	121,961	110,465	11,496	10.4%
Wholesale and retail electric sales	72,376	92,134	(19,758)	(21.4)%
Total sales	194,337	202,599	(8,262)	(4.1)%

Trading volumes of 26,924 GWhs and 24,001 GWhs for 2005 and 2004, respectively, are not included in the table above.

Electric sales to affiliates. Revenue from sales to affiliates increased $1,026 million in 2005 as compared to the prior year. The increase in revenue from sales to affiliates was primarily due to a $635 million increase from overall higher prices associated with Generation's PPA with ComEd and a $391 million increase from higher electric sales volume. As a result of the Amended and Restated Purchase Power Agreement as of April 30, 2004 with ComEd, effective January 1, 2005, Generation began receiving overall higher prices from ComEd for its purchased power. The higher sales volumes to ComEd and PECO resulted from favorable weather conditions in the summer and winter periods in the ComEd and PECO service territories and an increase in the number of customers returning from alternative electric suppliers in 2005 compared to the prior year.

Wholesale and retail electric sales. The changes in Generation's wholesale and retail electric sales for 2005 compared to 2004 consisted of the following:

	Increase (decrease)
Price	$ 879
Volume	(526)
Sale of Boston Generating	(239)
Increase in wholesale and retail electric sales	$ 114

(a) Sales to Boston Generating of $9 million were included in other revenue for 2004.

Wholesale and retail sales increased $114 million due to an increase in market prices in 2005 compared to the prior year. The increase in market prices was primarily driven by higher fuel prices (e.g. oil and natural gas). The increase in price was partially offset by lower volumes of generation capacity sold to the market in 2005 as compared to 2004. Generation had less power to sell into the market as a result of higher demand for power sold to affiliates in 2005 and the expiration of its purchase power agreement with Midwest Generation in 2004. The remaining decrease in wholesale and retail sales of $239 million was due to the sale of Boston Generating in May 2004.

Retail gas sales. Retail gas sales increased $165 million primarily due to significantly higher gas prices in the overall market.

Trading portfolio. Trading portfolio income increased $17 million in 2005 compared to the prior year due to an increase in trading volumes. See Quantitative and Qualitative Disclosures About Market Risk—Proprietary Trading Activities for further information.

Other revenues. The increase in other revenues in 2005 was primarily due to an increase of $60 million associated with revenue from Generation's operating services agreements with PSEG and Tamuin International, Inc. This increase was partially offset by a decrease of $39 million related to lower fuel sales, a reduction in decommissioning revenue from ComEd and lower sales from tolling and gas management agreements. The increased revenue from the operating services agreements was substantially offset by a corresponding increase in Generation's operating and maintenance expense.

Purchased Power and Fuel Expense. Generation's supply sources are summarized below:

Supply Source (in GWhs)	2005	2004	Variance	% Change
Nuclear generation [a]	137,936	136,621	1,315	1.0%
Purchases—non-trading portfolio	42,623	48,968	(6,345)	(13.0)%
Fossil and hydroelectric generation [b]	13,778	17,010	(3,232)	(19.0)%
Total supply	194,337	202,599	(8,262)	(4.1)%

(a) Represents Generation's proportionate share of the output of its nuclear generating plants.
(b) Fossil and hydroelectric generation decreased by 4,978 GWhs as a result of lower fossil fuel generation due to the sale of Boston Generating in May 2004.

The changes in Generation's purchased power and fuel expense for 2005 compared to 2004 consisted of the following:

	Increase (decrease)
Price	$ 845
Volume	(93)
Mark-to-market	9
Sale of Boston Generating	(226)
Other	(64)
Increase in purchased power and fuel expense	$ 471

Price. The increase reflects overall higher market energy prices for purchased power and higher natural gas and oil prices in 2005 as compared to the prior year. The increase in unplanned outages in 2005 occurred during periods of higher energy prices, which caused Generation to purchase power in the market at high prices. Additionally, overall energy market conditions resulted in higher prices for raw materials (i.e., oil, gas and coal) used in the production of electricity. These factors contributed to an increase in the average purchase power costs of approximately $13 per MWh for 2005.

Volume. The reduced volume in 2005 as compared to 2004 was primarily due to lower volumes of purchased power in the market slightly offset by higher nuclear and fossil generation needed to meet ComEd's and PECO's load requirements.

Mark-to-market. Mark-to-market losses on hedging activities were $12 million for 2005 compared to losses of $3 million for 2004.

Boston Generating. The decrease in purchased power and fuel expense associated with Boston Generating was due to the sale of the business in May 2004.

Other. Other decreases in purchased power and fuel expense were primarily due to lower transmission expense in 2005 as compared to the prior year resulting from the expansion of the PJM region due to new transmission owners joining PJM and reduced inter-region transmission charges, primarily associated with ComEd's integration into PJM on May 1, 2004.

Generation's average margin per MWh of electricity sold for 2005 and 2004 was as follows:

($/MWh)	2005	2004	% Change
Average electric revenue			
Electric sales to affiliates (a)	$39.15	$33.94	15.4%
Wholesale and retail electric sales	46.16	35.03	31.8%
Total—excluding the trading portfolio	41.76	34.43	21.3%
Average electric supply cost (b)—excluding the trading portfolio	$20.11	$17.60	14.3%
Average margin—excluding the trading portfolio	$21.65	$16.83	28.6%

(a) The increase in $/MWh is due to higher prices in 2005 associated with Generation's PPA with ComEd.

(b) Average supply cost includes purchased power and fuel costs associated with electric sales. Average electric supply cost does not include fuel costs associated with retail gas sales.

Nuclear fleet operating data and purchased power cost data for 2005 and 2004 were as follows:

	2005	2004
Nuclear fleet capacity factor (a)	93.5%	93.5%
Nuclear fleet production cost per MWh (a)	$13.03	$12.43
Average purchased power cost for wholesale operations per MWh	$60.27	$47.11

(a) Excludes Salem, which is operated by PSEG Nuclear.

The nuclear fleet capacity factor was the same in 2005 as compared to 2004. Higher costs associated with the planned refuel outages and higher non-outage operating costs resulted in a higher production cost per MWh produced for 2005 as compared to 2004. There were nine planned refueling outages and 25 non-refueling outages in 2005 compared to nine planned refuel outages and 20 non-refueling outages in 2004.

During 2004, both Quad Cities' units operated intermittently at Extended Power Uprate (EPU) generation levels due to performance issues with their steam dryers. As of the third quarter of 2005, both of the Quad Cities' units returned to EPU generation levels after extensive testing and load verification on new replacement steam dryers was completed. Near the end of 2005, the generation levels of both Quad Cities' units were again reduced to pre-EPU generation levels to address vibration–related equipment issues not directly related to the steam dryers. The units will be brought back to full EPU generation levels after all issues are addressed to ensure safe and reliable operations at the EPU output levels which is expected to occur in 2006.

Operating and Maintenance Expense. The increase in operating and maintenance expense for 2005 compared to 2004 consisted of the following:

	Increase (decrease)
Nuclear refueling and non-outage operating costs	$ 78
DOE Settlement in 2004	42
Tamuin International	44
Accrual for estimated future asbestos-related bodily injury claims	43
Nuclear operating services agreement	14
Pension, payroll and benefit costs	(58)
Boston Generating	(62)
Decommissioning-related activity	(38)
Other	24
Increase in operating and maintenance expense	$ 87

This net $87 million increase is attributable to the following:

- A $78 million increase in nuclear refueling and non-outage operating costs due to an increase in nuclear maintenance costs of $44 million related to planned nuclear refueling outages for plants operated by Generation and the co-owned Salem Generating Station, and increases in other nuclear operating and maintenance expenses of $34 million, primarily security and inflationary costs;
- A $42 million reimbursement in 2004 of costs incurred prior to 2004 for the storage of spent nuclear fuel associated with the DOE Settlement Agreement;
- A $44 million increase in expenses associated with Generation's operating service agreement with a subsidiary of Tamuin International, Inc;
- The establishment of a $43 million liability in June 2005 for estimated future asbestos-related bodily injury claims (see further discussion in Note 20 to Exelon's Notes to Consolidated Financial Statements); and
- Costs of $14 million in 2005 associated with the Salem and Hope Creek Operating Services Agreement with PSEG, the reimbursement of which is included in other revenues.

The increases in operating and maintenance expense described above were partially offset by lower payroll-related expenses (a $58 million reduction), the elimination of $62 million in expenses at Boston Generating due to its sale in May 2004 and a $36 million reduction in the contractual obligation that Generation has to ComEd related to decommissioning obligations (which is included in the $38 million of decommissioning-related activity in the table above).

Depreciation and Amortization. The decrease in depreciation and amortization expense for 2005 compared to 2004 was primarily due to the establishment of an ARC asset for retired nuclear units of $36 million recorded in the third quarter of 2004 which was immediately impaired through depreciation expense as this asset was associated with retired nuclear units that do not have any remaining useful life. This decrease was partially offset by increased depreciation expense due to recent capital additions.

Taxes Other Than Income. The increase in taxes other than income for 2005 as compared to 2004 was primarily due to a net increase in Generation's reserves related to payroll taxes, sales and use taxes and other taxes other than income, partially offset by a reduction in taxes resulting from the sale of Boston Generating in May 2004.

Other, Net. The decrease in other income for 2005 as compared to the prior year was primarily due to the $85 million gain ($52 million, net of taxes) on the disposal of Boston Generating recorded in May 2004, partially offset by gains of $36 million realized in the second quarter of 2005 related to the decommissioning trust fund investments for the AmerGen plants, primarily associated with changes in Generation's investment strategy.

Effective Income Tax Rate. The effective income tax rate from continuing operations was 39.0% for 2005 compared to 38.1% for 2004. See Note 12 of Generation's Notes to the Consolidated Financial Statements in Exelon's 2005 Form 10-K for further discussion of the change in the effective income tax rate.

Discontinued Operations. On January 31, 2005, subsidiaries of Generation completed a series of transactions that resulted in Generation's sale of its investment in Sithe. In addition, Generation has sold or wound down substantially all components of AllEnergy, a business within Exelon Energy. Accordingly, the results of operations and the gain on the sale of Sithe and results of AllEnergy have been presented as discontinued operations for 2005 within Generation's Consolidated Statements of Income. See Notes 2 and 3 of Exelon's Notes to Consolidated Financial Statements for further information regarding the presentation of Sithe's and AllEnergy's results of operations as discontinued operations and the sale of Sithe as discontinued operations.

Cumulative Effect of Changes in Accounting Principles. The cumulative effect of changes in accounting principles reflects the impact of adopting FIN 47 as of December 31, 2005 and the consolidation of Sithe in accordance with FIN 46-R as of March 31, 2004. See Notes 1 and 14 of Generation's Notes to Consolidated Financial Statements in Exelon's 2005 Form 10-K for further discussion of the consolidation of Sithe and the adoption of FIN 47, respectively.

Year Ended December 31, 2004 Compared To Year Ended December 31, 2003

Significant Operating Trends—Exelon

Exelon Corporation	2004	2003	Favorable (unfavorable) variance
Operating revenues	$14,133	$15,148	$(1,015)
Purchased power and fuel expense	4,929	6,194	1,265
Operating and maintenance expense	3,700	3,915	215
Impairment of Boston Generating, LLC long-lived assets	—	945	945
Depreciation and amortization	1,295	1,115	(180)
Operating income	3,499	2,409	1,090
Other income and deductions	(922)	(1,123)	201
Income from continuing operations before income taxes and minority interest	2,577	1,286	1,291
Income taxes	713	389	(324)
Income from continuing operations	1,870	892	978
Loss from discontinued operations, net of income taxes	(29)	(99)	70
Income before cumulative effect of changes in accounting principles	1,841	793	1,048
Cumulative effect of changes in accounting principles	23	112	(89)
Net income	1,864	905	959
Diluted earnings per share	2.78	1.38	1.40

Net Income. Net income for 2004 reflects income of $32 million for the adoption of FIN 46-R, partially offset by a loss of $9 million related to the adoption of Emerging Issues Task Force (EITF)

Issue No. 03-16, “Accounting for Investments in Limited Liability Companies” (EITF 03-16). Net income for 2003 reflects income of $112 million for the adoption of SFAS No. 143. See Note 1 of Exelon’s Notes to Consolidated Financial Statements for further information regarding the adoptions of FIN 46-R, EITF 03-16 and SFAS No. 143.

Operating Revenues. Operating revenues decreased primarily due to decreased revenues at Enterprises due to the sale of InfraSource in 2003, the sale of Boston Generating in 2004 and Generation’s adoption of EITF No. 03-11, “Reporting Realized Gains and Losses on Derivative Instruments That Are Subject to FASB Statement No. 133, ‘Accounting for Derivative Instruments and Hedging Activities,’ and not ‘Held for Trading Purposes’ as Defined in EITF Issue No. 02-3, ‘Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities’” (EITF 03-11) in the first quarter of 2004, which changed the presentation of certain power transactions and decreased 2004 operating revenues by $980 million. The adoption of EITF 03-11 had no impact on net income. Operating revenues were favorably affected by Generation’s acquisition of the remaining 50% of AmerGen in 2003. Operating revenues were also favorably affected by increased volume growth and transmission revenues at ComEd and PECO collected from PJM, partially offset by unfavorable weather conditions and customer choice initiatives. See further discussion of operating revenues by segment below.

Purchased Power and Fuel Expense. Purchased power and fuel expense decreased primarily due to Generation’s adoption of EITF 03-11 during 2004 which resulted in a decrease in purchased power expense and fuel expense of $980 million. In addition, purchased power decreased due to Generation’s acquisition of the remaining 50% of AmerGen in 2003, which was only partially offset by an increase in fuel expense, and the sale of Boston Generating in 2004. Purchased power represented 24% of Generation’s total supply in 2004 compared to 37% in 2003. Purchased power also decreased at ComEd and PECO due to unfavorable weather conditions and customer choice. See further discussion of purchased power and fuel expense by segment below.

Impairment of the Long-Lived Assets of Boston Generating. Generation recorded a $945 million charge (before income taxes) during 2003 to impair the long-lived assets of Boston Generating.

Operating and Maintenance Expense. Operating and maintenance expense decreased primarily as a result of decreased expenses at InfraSource due to its sale in 2003 and decreased severance and severance-related expenses, partially offset by increased expenses at Generation due to the acquisition of the remaining 50% of AmerGen. Operating and maintenance expense increased $65 million due to investments in synthetic fuel-producing facilities made in the fourth quarter of 2003 and the third quarter of 2004. See further discussion of operating and maintenance expenses by segment below.

Depreciation and Amortization Expense. The increase in depreciation and amortization expense was primarily due to additional plant placed in service at ComEd, PECO and Generation, the acquisition of the remaining 50% in AmerGen in 2003 and the establishment of an ARC asset for retired nuclear units in 2004 which was immediately impaired through depreciation expense in 2004. The increase also resulted from increased amortization expense due to investments made in the fourth quarter of 2003 and the third quarter of 2004 in synthetic fuel-producing facilities and increased competitive transition charge amortization at PECO. These increases were partially offset by reduced depreciation and amortization expense at Enterprises due to the sale of InfraSource in 2003.

Operating Income. Exclusive of the changes in operating revenues, purchased power and fuel expense, the impairment of Boston Generating’s long-lived assets, operating and maintenance expense and depreciation and amortization expense discussed above, the change in operating income was primarily the result of increased taxes other than income in 2004 as compared to 2003, primarily due to the reduction of certain real estate tax accruals at PECO and Generation during 2003.

Other Income and Deductions. Other income and deductions in 2004 reflects interest expense of $828 million, equity in losses of unconsolidated affiliates of $154 million, debt retirement charges of $130 million (before income taxes) recorded at ComEd associated with an accelerated liability management plan, and an $85 million gain (before income taxes) on the 2004 sale of Boston Generating. Other income and deductions in 2003 reflects interest expense of $873 million and impairment charges of $255 million (before income taxes) related to Generation's investment in Sithe. Equity in earnings of unconsolidated affiliates decreased by $187 million due to the acquisition of the remaining 50% of AmerGen in 2003, the deconsolidation of certain financing trusts during 2003 and investments in synthetic fuel-producing facilities made in the fourth quarter of 2003 and the third quarter of 2004.

Effective Income Tax Rate. The effective income tax rate from continuing operations was 28% for 2004 compared to 30% for 2003. The decrease in the effective rate was primarily attributable to investments in synthetic fuel-producing facilities made in the fourth quarter of 2003.

Discontinued Operations. 2004 and 2003 discontinued operations consist of Sithe's 2004 results (beginning April 1, 2004), certain qualifying components of Enterprises, and AllEnergy. AllEnergy is a business within Exelon Energy, which is a business within Generation. A discussion of the results of Sithe and AllEnergy is included in the Generation segment results discussion below. Enterprises' after-tax loss from discontinued operations of $78 million in 2003 and $13 million in 2004 decreased by $65 million primarily due to a 2004 gain on the sale of the Chicago operations of Thermal and a decrease in operating and maintenance expense of $401 million, partially offset by a decrease in revenues. At December 31, 2004, the remaining assets of the businesses associated with the former Enterprises segment totaled approximately $274 million in comparison to $697 million at December 31, 2003.

Results of Operations by Business Segment

Historically, Exelon had reported Enterprises as a segment. Exelon sold or unwound substantially all components of Enterprises in 2004 and 2003. As a result, Enterprises is no longer reported as a segment and is included within the "other" category within the results of operations by business segment below. Other consists of corporate operations, including Exelon Business Services Company, Enterprises and investments in synthetic fuel-producing facilities.

The comparison of 2004 and 2003 operating results and other statistical information set forth below include intercompany transactions, which are eliminated in Exelon's consolidated financial statements.

Transfer of Exelon Energy Company from Enterprises to Generation. Effective January 1, 2004, Enterprises' competitive retail sales business, Exelon Energy Company, was transferred to Generation. The 2003 information related to the Generation segment discussed below has been adjusted to reflect the transfer of Exelon Energy Company from Enterprises to the Generation segment. Exelon Energy Company's 2003 results, excluding intercompany eliminations, were as follows:

Total revenues	$660
Intersegment revenues	4
Operating revenues and purchased power from affiliates	200
Depreciation and amortization	1
Operating expenses	648
Interest expense	1
Income from continuing operations before income taxes	6
Income taxes	3
Income from continuing operations	3
Loss from discontinued operations, net of income taxes	(21)
Net loss	(18)

Income (Loss) from Continuing Operations

	2004	2003	Favorable (unfavorable) variance
ComEd	$ 676	$ 702	$ (26)
PECO	455	473	(18)
Generation	657	(238)	895
Other	82	(45)	127
Total	$1,870	$ 892	$978

Income (Loss) Before Cumulative Effect of Changes in Accounting Principles by Business Segment

	2004	2003	Favorable (unfavorable) variance
ComEd	$ 676	$ 702	$ (26)
PECO	455	473	(18)
Generation	641	(259)	900
Other	69	(123)	192
Total	$1,841	$ 793	$1,048

Net Income (Loss) by Business Segment

	2004	2003	Favorable (unfavorable) variance
ComEd	$ 676	$ 707	$ (31)
PECO	455	473	(18)
Generation	673	(151)	824
Other	60	(124)	184
Total	$1,864	$ 905	$959

Results of Operations—ComEd

	2004	2003	Favorable (unfavorable) variance
Operating revenues	$5,803	$5,814	$ (11)
Operating expenses			
Purchased power	2,588	2,501	(87)
Operating and maintenance	897	1,093	196
Depreciation and amortization	410	386	(24)
Taxes other than income	291	267	(24)
Total operating expense	4,186	4,247	61
Operating income	1,617	1,567	50
Other income and deductions			
Interest expense	(369)	(423)	54
Distributions on mandatorily redeemable preferred securities	—	(26)	26
Equity in losses of unconsolidated affiliates	(19)	—	(19)
Net loss on extinguishment of long-term debt	(130)	—	(130)
Other, net	34	49	(15)
Total other income and deductions	(484)	(400)	(84)
Income before income taxes and cumulative effect of a change in accounting principle	1,133	1,167	(34)
Income taxes	457	465	8
Income before cumulative effect of a change in accounting principle	676	702	(26)
Cumulative effect of a change in accounting principle	—	5	(5)
Net Income	$ 676	$ 707	$ (31)

Net Income. ComEd's net income in 2004 decreased primarily due to costs associated with ComEd's accelerated retirement of long-term debt, partially offset by higher operating income. The decrease in operating and maintenance expense was primarily driven by lower severances charges.

Operating Revenues. The changes in operating revenues for 2004 compared to the 2003 consisted of the following:

	Increase (decrease)
Weather	$(113)
Customer choice	(104)
Rate changes and mix	(75)
Volume	178
Retail revenue	(114)
PJM transmission	164
T&O charges	(41)
Other	(20)
Wholesale and miscellaneous revenues	103
Decrease in operating revenues	$ (11)

Weather. The weather impact for the year ended December 31, 2004 was unfavorable compared to the same period in 2003 as a result of milder weather in 2004. Cooling degree-days decreased 12% and heating degree-days decreased 6% in the year ended December 31, 2004 compared to the same period in 2003.

Customer Choice. All ComEd customers have the choice to purchase energy from an alternative electric supplier. This choice generally does not impact the volume of deliveries, but affects revenue collected from customers related to energy supplied by ComEd; however, as of December 31, 2004, no alternative electric supplier had approval from the ICC, and no electric utilities had chosen, to enter the ComEd residential market for the supply of electricity.

	2004	2003
Retail customers purchasing energy from an alternative electric supplier:		
Volume (GWhs) [(a)]	20,939	17,317
Percentage of total retail deliveries	24%	20%
Retail customers purchasing energy from an alternative electric supplier or the ComEd PPO:		
Number of customers at period end	22,161	20,300
Percentage of total retail customers	[(b)]	[(b)]
Volume (GWhs) [(a)]	30,426	26,908
Percentage of total retail deliveries	35%	31%

(a) One GWh is the equivalent of one million kilowatthours (kWh).
(b) Less than one percent.

Rate Changes and Mix. In addition to a change in revenue from the change in rate mix due to changes in monthly usage patterns in all customer classes during 2004 compared to 2003, revenue changed as a result of rate changes. Starting in the June 2003 billing cycle, the increased wholesale market price of electricity and other adjustments to the energy component, decreased the collection of CTCs as compared to the respective prior year period. ComEd's CTC revenues decreased by $135 million for the year ended December 31, 2004 as compared to the same period in 2003. This decrease was partially offset by increased wholesale market prices which increased energy revenue received under the ComEd PPO and by increased average rates, resulting from a change in customer usage, paid by small and large commercial and industrial customers totaling $53 million. For the years ended December 31, 2004 and December 31, 2003, ComEd collected $169 million and $304 million, respectively, of CTC revenue. Under the current restructuring statute, no CTCs will be collected after 2006.

Volume. ComEd's electric revenues from higher delivery volume, exclusive of effects of weather and customer choice, increased due to an increased number of customers and increased usage per customer, generally across all customer classes.

PJM transmission. ComEd's transmission revenues and purchased power expense each increased by $164 million due to ComEd's May 1, 2004 entry into PJM.

T&O Charges. Prior to FERC orders issued in November 2004, ComEd collected T&O charges for energy flowing across ComEd's transmission system. Charges collected as the transmission owner were recorded in operating revenues. In addition after ComEd joined PJM on May 1, 2004, PJM allocated T&O collections to ComEd as a load serving entity. The collections received as a load serving entity were recorded as a decrease to purchased power expense. See Note 4 of Exelon's Notes to Consolidated Financial Statements for more information on T&O charges.

Purchased Power Expense. The changes in ComEd's purchased power expense for 2004 compared to 2003 consisted of the following:

	Increase (decrease)
PJM transmission	$164
Volume	94
PJM administrative fees	15
Customer choice	(87)
Weather	(57)
T&O charges	(22)
Prices	(7)
Other	(13)
Increase in purchased power expense	$ 87

PJM transmission. ComEd's transmission revenues and purchased power expense each increased by $164 million due to ComEd's May 1, 2004 entry into PJM. See "Operating Revenues" above.

Volume. ComEd's purchased power expense increased due to increases, exclusive of the effects of weather and customer choice, in the number of customers and average usage per customer, generally across all customer classes.

PJM administrative fees. ComEd began paying PJM administrative fees upon its full integration into PJM on May 1, 2004.

Customer choice. An increase in customer switching resulted in a reduction of purchased power expense, primarily due to ComEd's non-residential customers electing to purchase energy from an alternative electric supplier.

Weather. ComEd's purchased power expense decreased due to unfavorable weather conditions.

T&O changes. Prior to FERC orders issued in November 2004, ComEd collected T&O charges for energy flowing across ComEd's transmission system. Charges collected as the transmission owner were recorded in operating revenues. In addition, after ComEd joined PJM on May 1, 2004, PJM allocated T&O collections to ComEd as a load serving entity. The collections received as a load serving entity were recorded as a decrease to purchased power expense. See Note 4 of Exelon's Notes to Consolidated Financial Statements for more information on T&O charges.

Prices. ComEd's purchased power expense increased due to a change in the mix of average pricing related to ComEd's PPAs with Generation.

Operating and Maintenance Expense. The changes in operating and maintenance expense for the 2004 compared to 2003 consisted of the following:

	Increase (decrease)
Severance-related expenses	$(115)
Charge recorded at ComEd in 2003 [(a)]	(41)
Payroll expense [(b)]	(25)
Contractors	(18)
FERC annual fees [(c)]	(11)
Environmental charges	(10)
Allowance for uncollectible accounts expense	(9)
Incremental storm costs	(7)
Corporate allocations [(d)]	43
Other	(3)
Decrease in operating and maintenance expense	$(196)

(a) In 2003, ComEd reached an agreement with various Illinois retail market participants and other interested parties.
(b) Due to fewer employees in 2004 compared to 2003.
(c) After joining PJM on May 1, 2004, ComEd is no longer directly charged annual fees by the FERC. PJM pays the annual FERC fees.
(d) Higher corporate allocations primarily result from centralization of information technology, supply, human resources, communications, and finance functions into BSC from all of the Exelon operating companies, and changes in the corporate governance allocation calculation. Corporate governance allocations increased overall as a result of higher centralized costs distributed out of BSC, the sale of the Enterprises companies resulting in ComEd comprising a greater base percentage of Exelon, and an SEC-mandated change to the methodology used to allocate Exelon's corporate governance costs.

Depreciation and Amortization Expense. The changes in depreciation and amortization expense for 2004 compared to 2003 consisted of the following:

	Increase (decrease)
Depreciation expense	$21
Other amortization expense	3
Increase in depreciation and amortization expense	$24

ComEd's increase in depreciation expense is primarily due to capital additions. Recoverable transition costs amortization remained constant in 2004 as compared to 2003.

Taxes Other Than Income. The increase was primarily attributable to a $25 million credit in 2003 for use tax payments for periods prior to the PECO / Unicom Merger and a refund of $5 million for Illinois Electricity Distribution taxes in 2003 partially offset by a refund of $8 million for Illinois Electricity Distribution taxes in 2004.

Interest Expense. The reduction in interest expense was primarily due to scheduled principal payments, debt retirements and prepayments, and refinancings at lower rates.

Equity in Losses of Unconsolidated Affiliates. During 2004, ComEd recorded $19 million of equity in net losses of subsidiaries as a result of ComEd deconsolidating their financing trusts.

Net Loss on Extinguishment of Long-Term Debt. In 2004, Exelon initiated an accelerated liability management plan at ComEd that resulted in the retirement of approximately $768 million of long-term debt, of which $618 million was retired during the third quarter of 2004. During 2004, ComEd recorded a charge of $130 million associated with the retirement of debt under the plan. The components of this charge included the following: $86 million related to prepayment premiums; $12 million related to net unamortized premiums, discounts and debt issuance costs; $24 million of losses on reacquired debt previously deferred as regulatory assets; and $12 million related to settled cash-flow interest-rate swaps previously deferred as regulatory assets partially offset by $4 million of unamortized gain on settled fair value interest-rate swaps.

Other, net. The change in other, net primarily results from the reversal of a $12 million reserve for potential plant disallowance in 2003 as a result of an agreement with various Illinois retail market participants and other interested parties, a reduction of AFDUC equity of $5 million during 2004 as a result of lower construction work in process balances and a $5 million decrease in interest income on the long-term receivable from UII, LLC (formerly Unicom Investments, Inc.) as a result of a lower principal balance, which were partially offset by various other items.

Income Taxes. ComEd's effective income tax rate was 40.3% for 2004 and 39.8% 2003. See Note 10 of ComEd's Notes to Consolidated Financial Statements in Exelon's 2005 Form 10-K for further details of the components of the effective income tax rates.

ComEd Electric Operating Statistics and Revenue Detail

ComEd's electric sales statistics and revenue detail are as follows:

Retail Deliveries—(in GWhs)	2004	2003	Variance	% Change
Full service [(a)]				
Residential	26,463	26,206	257	1.0%
Small commercial & industrial	21,662	23,334	(1,672)	(7.2%)
Large commercial & industrial	6,913	6,955	(42)	(0.6%)
Public authorities & electric railroads	1,893	2,297	(404)	(17.6%)
Total full service	56,931	58,792	(1,861)	(3.2%)
PPO				
Small commercial & industrial	4,110	3,912	198	5.1%
Large commercial & industrial	5,377	5,677	(300)	(5.3%)
	9,487	9,589	(102)	(1.1%)
Delivery only [(b)]				
Small commercial & industrial	6,305	5,210	1,095	21.0%
Large commercial & industrial	14,634	12,110	2,524	20.8%
	20,939	17,320	3,619	20.9%
Total PPO and delivery only	30,426	26,909	3,517	13.1%
Total retail deliveries	87,357	85,701	1,656	1.9%

(a) Full service reflects deliveries to customers taking electric service under tariffed rates.
(b) Delivery only service reflects customers electing to receive generation service from an alternative electric supplier.

Electric Revenue	2004	2003	Variance	% Change
Full service [(a)]				
Residential	$2,295	$2,272	$ 23	1.0%
Small commercial & industrial	1,649	1,720	(71)	(4.1%)
Large commercial & industrial	380	413	(33)	(8.0%)
Public authorities & electric railroads	126	153	(27)	(17.6%)
Total full service	4,450	4,558	(108)	(2.4%)
PPO [(b)]				
Small commercial & industrial	274	256	18	7.0%
Large commercial & industrial	304	312	(8)	(2.6%)
	578	568	10	1.8%
Delivery only [(c)]				
Small commercial & industrial	128	132	(4)	(3.0%)
Large commercial & industrial	204	216	(12)	(5.6%)
	332	348	(16)	(4.6%)
Total PPO and delivery only	910	916	(6)	(0.7%)
Total electric retail revenues	5,360	5,474	(114)	(2.1%)
Wholesale and miscellaneous revenue [(d)]	443	340	103	30.3%
Total operating revenues	$5,803	$5,814	$ (11)	(0.2%)

(a) Full service revenue reflects deliveries to customers taking electric service under tariffed rates, which include the cost of energy and the cost of the transmission and the distribution of the energy.

(b) Revenues from customers choosing the PPO include an energy charge at market rates, transmission and distribution charges, and a CTC.

(c) Delivery only revenues reflect revenue under tariff rates from customers electing to receive generation service from an alternative electric supplier, which includes a distribution charge and a CTC. Prior to ComEd's full integration into PJM on May 1, 2004, ComEd's transmission charges received from alternative electric suppliers were included in wholesale and miscellaneous revenue.

(d) Wholesale and miscellaneous revenues include transmission revenue (including revenue from PJM), sales to municipalities and other wholesale energy sales.

Results of Operations—PECO

	2004	2003	Favorable (unfavorable) variance
Operating revenues	$4,487	$4,388	$ 99
Operating expenses			
Purchased power and fuel expense	2,172	2,096	(76)
Operating and maintenance	547	576	29
Depreciation and amortization	518	487	(31)
Taxes other than income	236	173	(63)
Total operating expense	3,473	3,332	(141)
Operating income	1,014	1,056	(42)
Other income and deductions			
Interest expense	(303)	(324)	21
Distributions on mandatorily redeemable preferred securities	—	(8)	8
Equity in losses of unconsolidated affiliates	(25)	—	(25)
Other, net	18	2	16
Total other income and deductions	(310)	(330)	20
Income before income taxes	704	726	(22)
Income taxes	249	253	4
Net income	455	473	(18)
Preferred stock dividends	3	5	2
Net income on common stock	$ 452	$ 468	$ (16)

Net Income. PECO's net income in 2004 decreased primarily due to higher taxes other than income, due primarily to the reduction of real estate tax accruals in 2003, and higher depreciation and amortization expense due to increased CTC amortization, partially offset by higher operating revenues net of purchased power and fuel expense and lower operating and maintenance expense.

Operating Revenues. The changes in PECO's operating revenues for 2004 compared to the 2003 consisted of the following:

	Electric	Gas	Total increase (decrease)
Volume	$148	$ 3	$151
Rate changes and mix	1	111	112
Weather	(63)	(21)	(84)
Customer choice	(78)	—	(78)
Retail revenue	8	93	101
PJM transmission	(15)	—	(15)
Other	3	10	13
Wholesale and miscellaneous revenues	(12)	10	(2)
Increase (decrease) in operating revenues	$ (4)	$103	$ 99

Volume. PECO's electric revenues increased as a result of higher delivery volume, exclusive of the effects of weather and customer choice, due to an increased number of customers and increased usage per customer, generally across all customer classes.

Rate changes and mix. Electric revenues increased $1 million at PECO as a result of a $20 million increase related to a scheduled phase-out of merger-related rate reductions, offset by a $19 million decrease reflecting a change in rate mix due to changes in monthly usage patterns in all customer classes during 2004 as compared to 2003.

PECO's gas revenues increased due to increases in rates through PUC-approved changes to the purchased gas adjustment clause that became effective March 1, 2003, June 1, 2003, December 1, 2003 and March 1, 2004. The average purchased gas cost rate per million cubic feet for 2004 was 33% higher than the rate in 2003. PECO's purchased gas cost rates were reduced effective December 1, 2004.

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 other months are referred to as "favorable weather conditions" because these weather conditions result in increased sales of electricity and gas. Conversely, mild weather reduces demand. Revenues were negatively affected by unfavorable weather conditions at PECO in 2004 compared 2003. In the PECO service territory, cooling and heating degree-days were relatively unchanged and 5% lower, respectively, than the prior year.

Customer choice. For 2004 and 2003, 12% and 9%, respectively, of energy delivered to PECO's retail customers was provided by an alternative electric supplier.

All PECO customers have the choice to purchase energy from an alternative electric supplier. This choice generally does not impact the volume of deliveries, but affects revenue collected from customers related to supplied energy and generation service. Also, operating income is not affected by customer choice since any increase or decrease in revenues is completely offset by any related increase or decrease in purchased power expense.

	2004	2003
Retail customers purchasing energy from an alternative electric supplier:		
Number of customers at period end	101,500	312,600
Percentage of total retail customers	7%	20%
Volume (GWhs)	4,605	3,135
Percentage of total retail deliveries	12%	9%

The increase in energy provided by alternative electric suppliers was due to the assignment of residential customers to alternative electric suppliers for a one-year term beginning in December 2003, as required by the PAPUC and PECO's final electric restructuring order. The decrease in the number of customers served by alternative electric suppliers at year-end 2004 was due to these residential customers returning to PECO as their energy provider in December 2004.

Purchased Power and Fuel Expense*.* The changes in PECO's purchased power and fuel expense for 2004 compared to 2003 consisted of the following:

	Electric	Gas	Total increase (decrease)
Volume	$ 69	$ (2)	$ 67
PJM transmission	(15)	—	(15)
Prices	18	111	129
Customer choice	(78)	—	(78)
Weather	(27)	(15)	(42)
Other	—	15	15
Increase (decrease) in purchased power and fuel expense	$(33)	$109	$ 76

Volume. PECO's purchased power and fuel expense increased due to increases, exclusive of the effects of weather and customer choice, in the number of customers and average usage per customer, generally across all customer classes.

Prices. PECO's purchased power expense increased due to a change in the mix of average pricing related to PECO's PPAs with Generation. Fuel expense for gas increased due to higher gas prices. See "Operating Revenues" above.

Customer choice. An increase in customer switching resulted in a reduction of purchased power expense, primarily due to PECO's residential customers selecting or being assigned to purchase energy from an alternative electric supplier.

Weather. PECO's purchased power and fuel expense decreased due to unfavorable weather conditions.

Other. PECO's fuel expense increased primarily due to increased off-system sales of gas.

Operating and Maintenance Expense. The changes in operating and maintenance expense for the 2004 compared to 2003 consisted of the following:

	Increase (decrease)
Severance-related expenses	$(17)
Automated meter reading system implementation costs at PECO in 2003	(16)
Storm costs [(a)]	(14)
Payroll expense [(b)]	(11)
Allowance for uncollectible accounts expense	(4)
Corporate allocations [(c)]	34
Other	(1)
Decrease in operating and maintenance expense	$(29)

(a) Storm costs were significantly higher in 2003 primarily as a result of Hurricane Isabel.
(b) PECO had fewer employees in 2004 compared to 2003.
(c) Higher corporate allocations primarily result from centralization of information technology, supply, human resources, communications, and finance functions into BSC from all of the Exelon operating companies, and changes in the corporate governance allocation calculation. Corporate governance allocations increased overall as a result of higher centralized costs distributed out of BSC, the sale of the Enterprises companies resulting in PECO comprising a greater base percentage of Exelon, and an SEC-mandated change to the methodology used to allocate Exelon's corporate governance costs.

Depreciation and Amortization Expense. The changes in depreciation and amortization expense for 2004 compared to 2003 consisted of the following:

	Increase (decrease)
Competitive transition charge amortization	$31
Depreciation expense	1
Other amortization expense	(1)
Increase in depreciation and amortization expense	$31

PECO's additional amortization of the CTC is in accordance with PECO's original settlement under the Pennsylvania Competition Act.

Taxes Other Than Income. The increase in taxes other than income in 2004 was primarily attributable to a $58 million reduction of real estate tax accruals during 2003 and $12 million related to the reversal of a use tax accrual in 2003 resulting from an audit settlement, partially offset by $4 million of lower payroll taxes in 2004.

Interest Expense and Distributions on Mandatorily Redeemable Preferred Securities. The aggregate of interest expense and distributions on mandatorily redeemable preferred securities decreased primarily due to lower outstanding debt and refinancings at lower rates, partially offset by a reversal in 2003 of accrued interest expense on Federal income taxes of $8 million to reflect actual interest paid. Effective December 31, 2003, with the adoption of FIN 46-R, PECO deconsolidated its financing trusts (see Note 1 of Exelon's Notes to Consolidated Financial Statements). PECO no longer records distributions on mandatorily redeemable preferred securities of subsidiaries but records interest expense to affiliates related to PECO's obligations to the financing trusts.

Equity in Losses of Unconsolidated Affiliates. During 2004, PECO recorded $25 million of equity in net losses of subsidiaries as a result of deconsolidating its financing trusts.

Other, Net. The increase was primarily attributable to a reversal in 2003 of accrued interest on Federal income taxes of $14 million to reflect actual interest received and gains on disposition of assets in 2004.

Income Taxes. PECO's effective income tax rate was 35.4% for 2004 compared to 34.8% for 2003. See Note 8 of PECO's Notes to Consolidated Financial Statements in Exelon's 2005 Form 10-K for further details of the components of the effective income tax rates.

PECO Electric Operating Statistics and Revenue Detail

PECO's electric sales statistics and revenue detail are as follows:

Retail Deliveries—(in GWhs)	2004	2003	Variance	% Change
Full service [a]				
Residential	10,349	11,358	(1,009)	(8.9%)
Small commercial & industrial	6,728	6,624	104	1.6%
Large commercial & industrial	14,908	14,739	169	1.1%
Public authorities & electric railroads	914	897	17	1.9%
Total full service	32,899	33,618	(719)	(2.1%)
Delivery only [b]				
Residential	2,158	900	1,258	139.8%
Small commercial & industrial	1,687	1,455	232	15.9%
Large commercial & industrial	760	780	(20)	(2.6%)
Total delivery only	4,605	3,135	1,470	46.9%
Total retail deliveries	37,504	36,753	751	2.0%

(a) Full service reflects deliveries to customers taking electric service under tariffed rates.
(b) Delivery only service reflects customers receiving electric generation service from an alternative electric supplier.

Electric Revenue	2004	2003	Variance	% Change
Full service [a]				
Residential	$1,317	$1,444	$(127)	(8.8%)
Small commercial & industrial	756	753	3	0.4%
Large commercial & industrial	1,113	1,090	23	2.1%
Public authorities & electric railroads	80	80	—	—
Total full service	3,266	3,367	(101)	(3.0%)
Delivery only [b]				
Residential	164	65	99	152.3%
Small commercial & industrial	86	75	11	14.7%
Large commercial & industrial	20	21	(1)	(4.8%)
Total delivery only	270	161	109	67.7%
Total electric retail revenues	3,536	3,528	8	0.2%
Miscellaneous revenue [c]	203	215	(12)	(5.6%)
Total electric and other revenue	$3,739	$3,743	$ (4)	(0.1%)

(a) Full service revenue reflects revenue from customers taking electric service under tariffed rates, which includes the cost of energy, the cost of the transmission and the distribution of the energy and a CTC.
(b) Delivery only revenue reflects revenue from customers receiving generation service from an alternative electric supplier, which includes a distribution charge and a CTC.
(c) Miscellaneous revenues include transmission revenue from PJM and other wholesale energy sales.

PECO Gas Sales Statistics and Revenue Detail

PECO's gas sales statistics and revenue detail were as follows:

Deliveries to customers (in million cubic feet (mmcf))	2004	2003	Variance	% Change
Retail sales	59,949	61,858	(1,909)	(3.1%)
Transportation	27,148	26,404	744	2.8%
Total	87,097	88,262	(1,165)	(1.3%)

Revenue	2004	2003	Variance	% Change
Retail sales	$ 702	$ 609	$ 93	15.3%
Transportation	18	18	—	—
Resales and other	28	18	10	55.6%
Total gas revenue	$ 748	$ 645	$ 103	16.0%

Results of Operations—Generation

	2004	2003	Favorable (unfavorable) variance
Operating revenues	$7,703	$8,586	$ (883)
Operating expenses			
Purchased power	2,307	3,620	1,313
Fuel	1,704	1,930	226
Operating and maintenance	2,201	1,874	(327)
Impairment of Boston Generating, LLC long-lived assets	—	945	945
Depreciation and amortization	286	200	(86)
Taxes other than income	166	120	(46)
Total operating expenses	6,664	8,689	2,025
Operating income (loss)	1,039	(103)	1,142
Other income and deductions			
Interest expense	(103)	(88)	(15)
Equity in earnings (losses) of unconsolidated affiliates	(14)	49	(63)
Other, net	130	(268)	398
Total other income and deductions	13	(307)	320
Income (loss) from continuing operations before income taxes and minority interest	1,052	(410)	1,462
Income taxes	401	(176)	(577)
Income from continuing operations before minority interest	651	(234)	885
Minority interest	6	(4)	10
Income (loss) from continuing operations	657	(238)	895
Discontinued operations			
Loss from discontinued operations	(45)	(35)	(10)
Income taxes	(29)	(14)	15
Loss from discontinued operations	(16)	(21)	5
Income (loss) before cumulative effect of changes in accounting principles	641	(259)	900
Cumulative effect of changes in accounting principles	32	108	(76)
Net income (loss)	$ 673	$ (151)	$ 824

Net Income (Loss). Generation's net income in 2004 increased from 2003 due to a number of factors. The increase in Generation's 2004 net income was driven primarily by charges incurred in 2003 for the impairment of the long-lived assets of Boston Generating of $945 million (before income taxes) and the impairment and other transaction-related charges of $280 million (before income taxes) related to Generation's investment in Sithe. Also, 2004 results were favorably affected by the acquisition of the remaining 50% of AmerGen and an increase in revenue, net of purchased power and fuel expense, primarily due to the decrease in average realized costs resulting from the increased success in the hedging program of fuel costs in 2004.

Cumulative effect of changes in accounting principles recorded in 2004 included a benefit of $32 million, net of income taxes, related to the adoption of FIN 46-R and in 2003 included income of $108 million, net of income taxes related to the of adoption of SFAS No. 143. See Note 1 of Exelon's Notes to Consolidated Financial Statements for further discussion of these effects.

Operating Revenues. Operating revenues decreased in 2004 as compared to 2003, primarily as a result of the adoption of EITF 03-11. The adoption of EITF 03-11 resulted in a decrease in revenues of $980 million in 2004 as compared with the prior year. Generation's sales in 2004 and 2003 were as follows:

Revenues (in millions)	2004	2003	Variance	% Change
Electric sales to affiliates	$ 3,749	$ 3,831	$ (82)	(2.1%)
Wholesale and retail electric sales	3,227	4,107	(880)	(21.4%)
Total energy sales revenues	6,976	7,938	(962)	(12.1%)
Retail gas sales	448	414	34	8.2%
Trading portfolio	—	1	(1)	(100.0%)
Other revenue (a)	279	233	46	19.7%
Total revenues	$ 7,703	$ 8,586	$ (883)	(10.3%)

Sales (in GWhs)	2004	2003	Variance	% Change
Electric sales to affiliates	110,465	112,688	(2,223)	(2.0%)
Wholesale and retail electric sales	92,134	112,816	(20,682)	(18.3%)
Total sales	202,599	225,504	(22,905)	(10.2%)

(a) Includes sales related to tolling agreements and fossil fuel sales.

Trading volumes of 24,001 GWhs and 32,584 GWhs for the years ended December 31, 2004 and 2003, respectively, are not included in the table above. The decrease in trading volume is a result of reduced volumetric and VAR trading limits in 2004, which are set by the Exelon Risk Management Committee and approved by the Board of Directors.

Electric Sales to Affiliates. Sales to ComEd and PECO declined $82 million in 2004 as compared to the prior year. The lower sales to ComEd and PECO were primarily driven by cooler than normal summer weather and lower average transfer prices in 2004 compared to the prior year.

Wholesale and Retail Electric Sales. The changes in Generation's wholesale and retail electric sales for the year ended December 31, 2004 compared to the same period in 2003, consisted of the following:

Generation	Increase (decrease)
Effects of EITF 03-11 adoption (a)	$(966)
Sale of Boston Generating	(370)
Addition of AmerGen operations	189
Other operations	267
Decrease in wholesale and retail electric sales	$(880)

(a) Does not include $14 million of EITF 03-11 reclassifications related to fuel sales that are included in other revenues.

The adoption of EITF 03-11 on January 1, 2004 resulted in the netting of certain revenues and the associated purchased power and fuel expense in 2004. The sale of Boston Generating in May 2004 resulted in less revenues from this entity in 2004 compared to the prior year. The acquisition of AmerGen resulted in increased market and retail electric sales of approximately $189 million in 2004.

The remaining increase in wholesale and retail electric sales was primarily due to higher volumes sold to the market at overall higher prices. The increase in market prices was primarily driven by higher coal prices in the Midwest region and higher oil and gas prices in the Mid-Atlantic region.

Retail Gas Sales. Retail gas sales increased $34 million as a result of higher natural gas prices in 2004.

Other revenues. Other revenues include increased sales from tolling agreements, offset by a decrease in fossil fuel revenues.

Purchased Power and Fuel Expense. Generation's supply of sales in 2004 and 2003, excluding the trading portfolio, was as follows:

Supply of Sales (in GWhs)	2004	2003	% Change
Nuclear generation [a]	136,621	117,502	16.3%
Purchases—non-trading portfolio [b]	48,968	83,692	(41.5%)
Fossil and hydroelectric generation [c, d]	17,010	24,310	(30.0%)
Total supply	202,599	225,504	(10.2%)

(a) Excludes AmerGen for 2003. AmerGen generated 20,135 GWhs during the year ended December 31, 2004.

(b) Sales in 2004 do not include 25,464 GWhs that were netted with purchased power GWhs as a result of the reclassification of certain hedging activities in accordance with EITF 03-11. Includes PPAs with AmerGen, which represented 12,667 GWhs in 2003.

(c) Fossil and hydroelectric supply mix changed as a result of decreased fossil fuel generation due to the sale of Boston Generating in May 2004.

(d) Excludes Sithe and Generation's investment in TEG and TEP.

The changes in Generation's purchased power and fuel expense for the year ended December 31, 2004 compared to the same period in 2003, consisted of the following:

Generation	Increase (decrease)
Effects of the adoption of EITF 03-11	$ (980)
Addition of AmerGen operations	(344)
Sale of Boston Generating	(290)
Midwest Generation	(122)
Price	(13)
Mark-to-market adjustments on hedging activity	(14)
Volume	267
Other	(43)
Decrease in purchased power and fuel expense	$(1,539)

Adoption of EITF 03-11. The adoption of EITF 03-11 resulted in a decrease in purchased power and fuel expense of $980 million.

Addition of AmerGen Operations. As a result of Generation's acquisition of the remaining 50% interest in AmerGen in December 2003, purchased power decreased $379 million. In prior periods, Generation reported energy purchased from AmerGen as purchased power expense. The decrease in purchased power was partially offset by an increase of $35 million related to AmerGen's nuclear fuel expense.

Sale of Boston Generating. The decrease in fuel and purchased power expense for Boston Generating is due primarily to the sale of the business in May 2004.

Midwest Generation. The volume of purchased power acquired from Midwest Generation declined in 2004 as a result of Generation exercising its option to reduce the capacity purchased from Midwest Generation, as announced in 2003.

Price. The decrease reflects the forward hedging of fuel at lower costs than 2003 realized costs.

Hedging Activity. Mark-to-market losses on hedging activities at Generation were $2 million for the year ended December 31, 2004 compared to losses of $16 million for 2003. Hedging activities in 2004 relating to Boston Generating operations accounted for a gain of $4 million and hedging activities relating to other Generation operations in 2004 accounted for losses of $6 million.

Volume. Generation experienced increases in purchased power and fuel expense due to increased market and retail electric sales throughout its various sales regions.

Other. Other decreases in purchased power and fuel expense were primarily due to lower transmission expense resulting from reduced inter-region transmission charges, primarily associated with ComEd's integration into PJM.

Generation's average margins per megawatt hour (MWh) sold for the years ended December 31, 2004 and 2003 were as follows:

($/MWh)	2004	2003	% Change
Average electric revenue			
Electric sales to affiliates	$33.94	$34.00	(0.2%)
Wholesale and retail electric sales	35.03	36.40	(3.8%)
Total—excluding the trading portfolio	34.43	35.20	(2.2%)
Average electric supply cost—excluding the trading portfolio (a)	$17.60	$24.61	(28.5%)
Average margin—excluding the trading portfolio	16.83	10.59	58.9%

(a) Average electric supply cost includes purchased power, and fuel costs associated with electric sales and PPAs with AmerGen in 2003. Average electric supply cost does not include purchased power and fuel cost associated with retail gas sales.

Impairment of the Long-Lived Assets of Boston Generating. In connection with the decision to transition out of the ownership of Boston Generating during the third quarter of 2003, Generation recorded a long-lived asset impairment charge of $945 million ($573 million net of income taxes). See Note 2 of Exelon's Notes to Consolidated Financial Statements for further discussion of the sale of Generation's ownership interest in Boston Generating.

Operating and Maintenance Expense. The changes in operating and maintenance expense for 2004 compared to 2003 consisted of the following:

Generation	Increase (decrease)
Addition of AmerGen operations	$331
Decommissioning-related costs (a)	50
Refueling outage costs (b)	50
Pension, payroll and benefit costs, primarily associated with The Exelon Way	(84)
DOE Settlement (c)	(52)
Sale of Boston Generating	(12)
Other	44
Increase in operating and maintenance expense	$327

(a) Includes $40 million due to AmerGen asset retirement obligation accretion not included in 2003.

(b) Includes refueling outage cost of $43 million at AmerGen not included in 2003.

(c) See Note 13 of Exelon's Notes to Consolidated Financial Statements for further discussion of the spent nuclear fuel storage settlement agreement with the DOE.

The increase in operating and maintenance expense was primarily due to the inclusion of AmerGen in Generation's consolidated results for 2004. Decommissioning-related costs increased primarily due to the inclusion of AmerGen in 2004 compared to the prior year. Accretion expense includes accretion of the asset retirement obligation and adjustments to offset the earnings impacts of certain decommissioning related activities revenues earned from ComEd and PECO, income taxes and depreciation of the ARC asset to zero. The increase in operating and maintenance expense was partially offset by reductions in payroll-related costs, the sale of Boston Generating in May 2004 and the settlement with the DOE to reimburse Generation for costs associated with storage of spent nuclear fuel.

Nuclear fleet operating data and purchased power costs data for the year ended December 31, 2004 and 2003 were as follows:

Generation	2004	2003
Nuclear fleet capacity factor [(a)]	93.5%	93.4%
Nuclear fleet production cost per MWh [(a)]	$ 12.43	$ 12.53
Average purchased power cost for wholesale operations per MWh [(b)]	$ 47.11	$ 43.25

(a) Includes AmerGen and excludes Salem, which is operated PSEG Nuclear.
(b) Includes PPAs with AmerGen in 2003.

The higher nuclear capacity factor and lower nuclear production costs were primarily due to ten fewer unplanned outages which offset the impact of one additional planned refuel outage. The lower production cost in 2004 as compared to 2003 was primarily due to the lower fuel costs and the impact of the spent fuel storage cost settlement agreement with the DOE which offset the added cost for one additional planned refuel outage and costs associated with the Dresden generator repairs during outages in the fourth quarter of 2004.

In 2004 as compared to 2003, the Quad Cities Units intermittently operated at pre-Extended Power Uprate (EPU) generation levels due to performance issues with their steam dryers.

Depreciation and Amortization. The increase in depreciation and amortization expense in 2004 as compared to 2003 was primarily due to the immediate expensing of an ARC, totaling $49 million, recorded in 2004 for which no useful life remains. The ARC was originally recorded in accordance with SFAS No. 143, which requires the establishment of an asset to offset the impact of an increased asset retirement obligation (ARO). See Note 14 of Exelon's Notes to Consolidated Financial Statements for more information on the 2004 update to the ARO and ARC. The remaining increase is due to capital additions and the consolidation of AmerGen. These increase were partially offset by a decrease in depreciation expense related to the Boston Generating facilities, which were sold in May 2004.

Effective Income Tax Rate. The effective income tax rate from continuing operations was 38% for 2004 compared to 43% for 2003. The decrease in the effective rate was primarily attributable to income taxes associated with nuclear decommissioning trust activity, income tax deductions related to non-taxable employee benefits and the dilution of the permanent income tax benefits due to the increase in pre-tax income in 2004. See Note 12 of Generation's Notes to the Consolidated Financial Statements in Exelon's 2005 Form 10-K for further discussion of the change in the effective income tax rate.

Discontinued Operations. In 2004, the loss from discontinued operations included Sithe's results from April 1, 2004 through the end of the year and the results from AllEnergy, a former subsidiary of Exelon Energy. Generation had accounted for the investment in Sithe as an unconsolidated equity method investment prior to its consolidation on March 31, 2004 pursuant to FIN 46-R. The loss from discontinued operations in 2003 included the results of AllEnergy. Sithe's net impact to Generation was a loss of $19 million in 2004, while AllEnergy produced $3 million of net income in 2004. In 2003, AllEnergy had a net loss of $21 million. See Note 2 of Exelon's Notes to Consolidated Financial Statements for further information.

Liquidity and Capital Resources

Exelon's businesses are capital intensive and require considerable capital resources. These capital resources are primarily provided by internally generated cash flows from operations. When necessary, Exelon obtains funds from external sources in the capital markets and through bank borrowings. Exelon's access to external financing on reasonable terms depends on Exelon and its subsidiaries' credit ratings and general business conditions, as well as that of the utility industry in general. If these conditions deteriorate to the extent that Exelon no longer has access to the capital markets at reasonable terms, Exelon has access to revolving credit facilities with aggregate bank commitments of $1.5 billion that it currently utilizes to support its commercial paper programs. See the "Credit Matters" section of "Liquidity and Capital Resources" for further discussion.

Exelon primarily uses its capital resources, including cash, to fund capital requirements, including construction expenditures, retire debt, pay common stock dividends, fund its pension obligations and invest in new and existing ventures. Exelon spends a significant amount of cash on construction projects that have a long-term return on investment. Additionally, ComEd and PECO operate in a rate-regulated environment in which the amount of new investment recovery may be limited and where such recovery takes place over an extended period of time. As a result of these factors, Exelon has historically operated with a working capital deficit. However, Exelon expects operating cash flows to be sufficient to meet operating and capital expenditure requirements. Future acquisitions that Exelon may undertake, other than the proposed merger with PSEG which will require the issuance of Exelon common stock in exchange for PSEG common stock, may involve external debt financing or the issuance of additional Exelon common stock.

Cash Flows from Operating Activities

ComEd's and PECO's cash flows from operating activities primarily result from sales of electricity and gas to a stable and diverse base of retail customers at fixed prices and are weighted toward the third quarter of each fiscal year. ComEd's and PECO's future cash flows will be affected by the economy, weather, customer choice and future regulatory proceedings on their revenues and their ability to achieve operating cost reductions. See Note 4 of Exelon's Notes to Consolidated Financial Statements for further discussion of regulatory proceedings. Generation's cash flows from operating activities primarily result from the sale of electric energy to wholesale customers, including ComEd and PECO. Generation's future cash flows from operating activities will be affected by future demand for and market prices of energy and its ability to continue to produce and supply power at competitive costs.

Cash flows from operations have been a reliable, steady source of cash flow, sufficient to meet operating and capital expenditures requirements. Taking into account the factors noted above, Exelon also obtains cash from non-operating sources such as the proceeds from the debt issuance in 2005 to fund Exelon's $2 billion pension contribution (see Note 10 of Exelon's Notes to Consolidated Financial Statements). Operating cash flows after 2006 could be negatively affected by changes in the rate regulatory environments of ComEd and PECO, although any effects are not expected to hinder the ability of PECO to fund its business requirements. Under Illinois law enacted in 1997, ComEd is required, beginning in 2007, to purchase energy in the wholesale energy markets in order to meet the retail energy needs of ComEd's customers because ComEd does not own any generation. If the price at which ComEd is allowed to sell energy beginning in 2007 is below ComEd's cost to procure and deliver electricity, there may be potential material adverse consequences to ComEd and, possibly, Exelon. On January 24, 2006, the ICC, by a unanimous vote, approved a reverse-auction competitive bidding process for procurement of power by ComEd for the time period after 2006. The procurement process is similar to the process described in the Procurement Case with some modifications to enhance consumer protection. The auction will be administered by an independent auction manager, with oversight by the ICC staff. The first auction is scheduled to take place during the fall of 2006, at which time ComEd's entire load will be up for bid. To mitigate the effects of changes in future prices, the load will be staggered in three-year contracts. To further mitigate the impact on its residential customers of transitioning to this process, ComEd has offered to develop a "cap and deferral" proposal to ease the impact of the expected increase in rates on residential customers, some or all of which could require regulatory or legislative approval to implement. A cap and deferral proposal, generally speaking, would limit the procurement costs that ComEd could pass through to its customers for a specified period of time and allow ComEd to collect any unrecovered procurement costs in later years.

Additionally, Exelon, through ComEd, has taken certain tax positions, which have been disclosed to the IRS, to defer the tax gain on the 1999 sale of its fossil generating assets. As discussed in Note 12 of Exelon's Notes to the Consolidated Financial Statements, this tax obligation is significant.

The following table provides a summary of the major items affecting Exelon's cash flows from operations:

	2005	2004	Variance
Net income	$ 923	$1,864	$ (941)
Add (subtract):			
Non-cash operating activities [(a)]	3,910	2,274	1,636
Income taxes	138	293	(155)
Changes in working capital and other noncurrent assets and liabilities [(b)]	(821)	237	(1,058)
Pension contributions and postretirement healthcare benefit payments, net	(2,003)	(270)	(1,733)
Net cash flows provided by operations	$ 2,147	$4,398	$(2,251)

(a) Represents depreciation, amortization and accretion, deferred income taxes, cumulative effect of a change in accounting principle, impairment of goodwill, investments and long-lived assets, and other non-cash charges.
(b) Changes in working capital and other noncurrent assets and liabilities exclude the changes in commercial paper, income taxes and the current portion of long-term debt.

The reduction of cash flows from operations during the current year is primarily the result of $2 billion of discretionary contributions to Exelon's pension plans during the first quarter of 2005, which was initially funded through a term loan agreement, as further described in the "Cash Flows from Financing Activities" section below. Of the total contribution, ComEd, PECO and Generation contributed $803 million, $109 million and $844 million, respectively. ComEd's and PECO's contributions were funded by capital contributions from Exelon. The Generation contribution was primarily funded by capital contributions from Exelon and included $2 million from internally generated funds. Exelon did not contribute to its pension plans in subsequent quarters of 2005. Discretionary tax-deductible pension plan payments were $439 million in 2004. Exelon also contributed $11 million during 2004 to the pension plans needed to satisfy minimum funding requirements of the Employee Retirement Income Security Act.

Cash flows provided by operations for 2005 and 2004 by registrant were as follows:

	2005	2004
Exelon	$2,147	$4,398
ComEd	247	1,330
PECO	704	983
Generation	972	1,947

Excluding the March 2005 discretionary pension contributions discussed above, changes in Exelon's, ComEd's, PECO's and Generation's cash flows from operations were generally consistent with changes in its results of operations, as adjusted by changes in working capital in the normal course of business.

In addition to the items mentioned in "Results of Operations" and the discretionary pension contributions discussed above, significant operating cash flow impacts for ComEd and Generation for 2005 and 2004 were as follows:

ComEd

- In the third quarter of 2005, ComEd settled $325 million of interest rate swaps that were designated as cash flow hedges for a loss of $15 million which was paid in October 2005. This was recorded as a pre-tax charge to net income because the underlying transaction for which these interest rate swaps were entered into is no longer probable of occurring.
- During 2004, ComEd paid $86 million for prepayment premiums on the retirement of debt.

Generation

- During 2005, Generation had net disbursements of counterparty collateral of $187 million compared to $73 million of net collections of counterparty collateral in 2004. The increase in cash outflows from 2004 was primarily due to changes in collateral requirements resulting from increased activity within exchange-based markets for energy and fossil fuel.
- During 2005, Generation had net payments of approximately $165 million primarily due to increased use of financial instruments to hedge future sales of power and future purchases of fossil fuel.
- During 2005, Exelon received a $102 million Federal income tax refund for capital losses generated in 2003 related to Generation's investment in Sithe, which were carried back to prior periods.
- In December 2004, TXU and Generation terminated a tolling agreement and entered into a new agreement. Upon termination of the original agreement, Generation received a cash payment of $172 million. The resulting gain was deferred and will be recognized as income over the contractual term of the new agreement.

Cash Flows from Investing Activities

Cash flows provided by (used in) investing activities for 2005 and 2004 by registrant were as follows:

	2005	2004
Exelon	$(2,487)	$(1,739)
ComEd	(479)	486
PECO	(241)	(251)
Generation	(1,294)	(1,103)

Capital expenditures by registrant and business segment for 2005 and projected amounts for 2006 are as follows:

	2005	2006
ComEd	$ 776	$ 925
PECO	298	333
Generation	1,067	1,115
Other [(a)]	24	68
Total Exelon capital expenditures	$2,165	$2,441

(a) Other primarily consists of corporate operations.

Projected capital expenditures and other investments for Exelon, ComEd, PECO and Generation are subject to periodic review and revision to reflect changes in economic conditions and other factors.

ComEd and PECO. Approximately 50% of the projected 2006 capital expenditures at ComEd and PECO are for continuing projects to maintain and improve the reliability of their transmission and distribution systems. The remaining amount is for capital additions to support new business and customer growth. Exelon is continuing to evaluate its total capital spending requirements. Exelon anticipates that ComEd's and PECO's capital expenditures will be funded by internally generated funds, borrowings and the issuance of debt or preferred securities or capital contributions from Exelon.

Generation. Generation's capital expenditures for 2005 reflect additions and upgrades to existing facilities (including material condition improvements during nuclear refueling outages) and nuclear fuel. Exelon anticipates that Generation's capital expenditures will be funded by internally generated funds, borrowings or capital contributions from Exelon.

Other significant investing activities for Exelon, ComEd, PECO and Generation for 2005 and 2004 were as follows:

Exelon

- Exelon contributed $102 million and $56 million to its investments in synthetic fuel-producing facilities during 2005 and 2004, respectively.
- Exelon received cash proceeds of $76 million, net of $2 million held in escrow at December 31, 2004, from the sale of its investments in affordable housing in 2004.
- Cash proceeds of $227 million, net of transaction costs and contingency payments on prior year dispositions, were received during 2004 from the sales of Exelon Thermal Holdings, Inc., substantially all of the operating businesses of Services, and Enterprises' investments in PECO TelCove and other equity method and cost basis investments of Enterprises.
- Early settlement on an acquisition note receivable from the 2003 disposition of InfraSource resulted in cash proceeds of $30 million during 2004.

ComEd

- As a result of its prior contributions to the Exelon intercompany money pool, $308 million and $97 million were returned to ComEd during 2005 and 2004, respectively.

PECO

- During 2005, $26 million was returned to PECO as a result of its prior contributions to the Exelon intercompany money pool and during 2004, $34 million was contributed by PECO.

Generation

- During 2005, Generation received approximately $52 million from Generation's nuclear decommissioning trust funds for reimbursement of expenditures previously incurred for nuclear plant decommissioning activities related to the retired units.
- 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 closed on the acquisition of Reservoir Capital Group's 50% interest in Sithe for cash payments of $97 million and the sale of 100% of Sithe to Dynegy, for net cash proceeds of $103 million. See Note 3 of Exelon's Notes to Consolidated Financial Statements for further discussion of the sale of Sithe.

- On March 31, 2004, Generation consolidated the assets and liabilities of Sithe under the provisions of FIN 46-R, which resulted in an increase in cash of $19 million. See Notes 1 and Note 3 of Exelon's Notes to Consolidated Financial Statements for further information regarding the FIN 46-R consolidation of Sithe.
- Generation received cash proceeds of $42 million from the January 2004 sale of three gas turbines.
- During 2004, Generation used $29 million of restricted cash related to Sithe's operating activities and used $11 million of restricted cash to support the operations of Boston Generating and provided $4 million for certain environmental obligations.

Cash Flows from Financing Activities

Cash flows provided by (used in) financing activities for 2005 and 2004 by registrant were as follows:

	2005	2004
Exelon	$ (19)	$(2,627)
ComEd	240	(1,820)
PECO	(500)	(676)
Generation	93	(739)

On March 7, 2005, Exelon entered into a $2 billion term loan agreement. The loan proceeds were used to fund discretionary contributions of $2 billion to Exelon's pension plans, including contributions of $803 million, $109 million and $842 million by ComEd, PECO and Generation, respectively. To facilitate the contributions by ComEd, PECO and Generation, Exelon contributed the corresponding amounts to the capital of each company. On April 1, 2005, Exelon entered into a $500 million term loan agreement that was subsequently fully borrowed to reduce this $2 billion term loan. During the second quarter of 2005, $200 million of this $500 million term loan, as well as the remaining $1.5 billion balance on the $2 billion term loan described above, were repaid with the net proceeds received from the issuance of the long-term senior notes discussed below. The $300 million outstanding balance under the term loan agreement bears interest at a variable rate determined, at Exelon's option, by either the Base Rate or the Eurodollar Rate (as defined in the term loan agreement). On November 30, 2005, the term loan was amended and restated to extend the agreement from December 1, 2005 to September 16, 2006. See Note 10 of Exelon's Notes to Consolidated Financial Statements for further discussion.

On June 9, 2005, Exelon issued and sold $1.7 billion of senior debt securities pursuant to its senior debt indenture, dated as of May 1, 2001, consisting of $400 million of 4.45% senior notes due 2010, $800 million of 4.90% senior notes due 2015 and $500 million of 5.625% senior notes due 2035. The net proceeds from the sale of the notes were used to repay the $1.5 billion in remaining principal due on the $2 billion term loan agreement and $200 million of the $500 million term loan agreement referenced above. Exelon may redeem some or all of the notes at any time prior to maturity at a specified redemption price. The notes are unsecured and rank equally with the other senior unsecured indebtedness of Exelon. Additionally, Exelon settled interest rate swaps for a net payment of $38 million and paid approximately $12 million of fees in connection with the debt offering.

In 2005, ComEd used funding received from $324 million of commercial paper to retire long-term debt.

In 2004, ComEd retired $1.2 billion of long-term debt, including $1.0 billion prior to its maturity and $206 million at maturity in accordance with an accelerated liability management plan and retired $728 million of long-term debt due to financing affiliates. Additionally, in 2004, Generation paid $27 million of a note payable to Sithe. During 2004, Exelon also issued $164 million of commercial paper, net of payments, and received cash proceeds of $33 million from the settlement of interest-rate swaps.

From time to time and as market conditions warrant, Exelon, ComEd, PECO and Generation may engage in long-term debt retirements via tender offers, open market repurchases or other viable options to strengthen their respective balance sheets.

Cash dividend payments and distributions in 2005 and 2004 by registrant were as follows:

	2005	2004
Exelon	$(1,070)	$(831)
ComEd	(498)	(457)
PECO	(473)	(394)
Generation	(857)	(662)

On January 24, 2006, Exelon's board of directors declared a quarterly dividend of $0.40 per share on Exelon's common stock. The dividend is payable on March 10, 2006 to shareholders of record at the end of the day on February 15, 2006. The dividend is payable on June 10, 2006, to shareholders of record at the end of the day on May 15, 2006, provided the Merger with PSEG with has not closed. See Market for Our Common Equity and Related Stockholder Matters for additional information.

The declaration and payment of dividends by ComEd is a matter for determination by the board of directors of ComEd. The ComEd board of directors, at a meeting held in December 2005, determined that the board would consider the dividend policy of ComEd at a subsequent meeting. The ComEd board has not discussed dividend policy in depth or taken action to establish or revise ComEd's dividend policy. If and to the extent that future dividends from ComEd are less than the level of dividends determined in accordance with past practices at ComEd, Exelon expects that distributions from Generation would be increased.

Exelon received proceeds from employee stock plans of $222 million and $240 million during 2005 and 2004, respectively.

Additionally, Exelon purchased treasury shares totaling $362 million and $82 million during 2005 and 2004, respectively.

Intercompany Money Pool. ComEd's net borrowings from the Exelon intercompany money pool increased $140 million during 2005. Generation's net borrowings from the Exelon intercompany money pool decreased $191 million and $162 million during 2005 and 2004, respectively.

Credit Issues

Exelon Credit Facilities

Exelon meets its short-term liquidity requirements primarily through the issuance of commercial paper by Exelon, ComEd, PECO and Generation. At December 31, 2005, Exelon, along with ComEd, PECO and Generation, participated with a group of banks in a $1 billion unsecured revolving facility maturing on July 16, 2009 and a $500 million unsecured revolving credit facility maturing on October 31, 2006. Both revolving credit agreements are used principally to support the commercial paper programs at Exelon, ComEd, PECO and Generation and to issue letters of credit.

At December 31, 2005, Exelon, ComEd, PECO and Generation had the following sublimits and available capacity under the credit agreements and the indicated amounts of outstanding commercial paper:

Borrower	Bank Sublimit (a)	Available Capacity (b)	Outstanding Commercial Paper
Exelon	$100	$100	$ —
ComEd	650	623	459
PECO	350	350	220
Generation	400	353	311

(a) Sublimits under the credit agreements can change upon written notification to the bank group.
(b) Available capacity represents the bank sublimit net of outstanding letters of credit. The amount of commercial paper outstanding does not reduce the available capacity under the credit facilities.

Interest rates on advances under the credit facilities are based on either prime or the London Interbank Offering Rate (LIBOR) plus an adder based on the credit rating of the borrower as well as the total outstanding amounts under the agreement at the time of borrowing. The maximum LIBOR adder is 170 basis points.

The average interest rates on commercial paper in 2005 for Exelon, ComEd, PECO and Generation were approximately 3.28%, 4.13%, 3.44% and 4.12%, respectively.

The credit agreements require Exelon, ComEd, PECO and Generation to maintain a minimum cash from operations to interest expense ratio for the twelve-month period ended on the last day of any quarter. The ratios exclude revenues and interest expenses attributable to securitization debt, certain changes in working capital, distributions on preferred securities of subsidiaries and, in the case of Exelon and Generation, revenues from Sithe and interest on the debt of its project subsidiaries. The following table summarizes the minimum thresholds reflected in the credit agreements for the twelve-month period ended December 31, 2005:

	Exelon	ComEd	PECO	Generation
Credit agreement threshold	2.65 to 1	2.25 to 1	2.25 to 1	3.25 to 1

At December 31, 2005, Exelon, ComEd, PECO and Generation were in compliance with the foregoing thresholds.

On February 10 through 13, 2006, Generation entered into separate additional credit facilities with aggregate bank commitments of $875 million, which may be drawn down in the form of loans and/or letters of credit. The additional credit facilities are for a term of 364 days and contain the same terms as the revolving credit facilities described above. The credit facilities will be used primarily to meet short-term funding requirements and to issue letters of credit.

Capital Structure. At December 31, 2005, the capital structures of Exelon, ComEd, PECO and Generation consisted of the following:

	Exelon Consolidated	ComEd	PECO (a)	Generation
Long-term debt	35%	25%	19%	29%
Long-term debt to affiliates (b)	20	12	50	—
Common equity	39	57	26	—
Member's equity	—	—	—	64
Preferred securities	—	—	1	—
Notes payable	6	6	4	7
Minority interest	—	—	—	—

(a) As of December 31, 2005, PECO's capital structure, excluding the deduction from shareholders' equity of the $1.2 billion receivable from Exelon (which amount is deducted for GAAP purposes as reflected in the table, but is excluded from the percentages in this footnote), consisted of 38% common equity, 1% preferred securities, 3% notes payable and 58% long-term debt, including long-term debt to unconsolidated affiliates.

(b) Includes $4.5 billion, $1.3 billion and $3.2 billion owed to unconsolidated affiliates of Exelon, ComEd and PECO, respectively, that qualify as special purpose entities under FIN 46-R. These special purpose entities were created for the sole purpose of issuing debt obligations to securitize intangible transition property and CTCs of ComEd and PECO or mandatorily redeemable preferred securities. See Note 1 of Exelon's Notes to Consolidated Financial Statements for further information regarding FIN 46-R.

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. Participation in the money pool is subject to authorization by the corporate treasurer. ComEd, PECO, Generation and BSC may participate in the money pool as lenders and borrowers, and Exelon and UII, LLC, a wholly owned subsidiary of Exelon, may participate as lenders. Funding of, and borrowings from, the money pool are predicated on whether the contributions and borrowings result in economic benefits. Interest on borrowings is based on short-term market rates of interest or, if from an external source, specific borrowing rates. Maximum amounts contributed to and borrowed from the money pool by participant during 2005 are described in the following table in addition to the net contribution or borrowing as of December 31, 2005:

	Maximum Contributed	Maximum Borrowed	December 31, 2005 Contributed (Borrowed)
ComEd	$517	$200	$(140)
PECO	210	20	8
Generation	54	540	(92)
BSC	30	156	(16)
UII, LLC	3	—	—
Exelon	242	—	241

Sithe Long-Term Debt

Debt totaling approximately $820 million was eliminated from the Consolidated Balance Sheets of Exelon and Generation as a result of the sale of Sithe on January 31, 2005. See Note 3 of Exelon's Notes to Consolidated Financial Statements for further discussion regarding the sale of Sithe.

Security Ratings

Exelon's, ComEd's, PECO's and Generation's access to the capital markets, including the commercial paper market, and their respective financing costs in those markets depend on the securities ratings of the entity that is accessing the capital markets. The following table shows the Registrants' securities ratings at December 31, 2005:

	Securities	Moody's Investors Service	Standard & Poor's Corporation	Fitch Ratings.
Exelon	Senior unsecured debt	Baa2	BBB	BBB+
	Commercial paper	P2	A2	F2
ComEd	Senior secured debt	Baa1 (a)	A-	A-
	Commercial paper	P2	A2	F2
	Transition bonds (b)	Aaa	AAA	AAA
PECO	Senior secured debt	A2	A-	A
	Commercial paper	P1	A2	F1
	Transition bonds (c)	Aaa	AAA	AAA
Generation	Senior unsecured debt	Baa1	BBB+	BBB+
	Commercial paper	P2	A2	F2

(a) Downgraded by Moody's Investor Service from A3 to Baa1 on December 15, 2005.
(b) Issued by ComEd Transitional Funding Trust, an unconsolidated affiliate of ComEd.
(c) Issued by PETT, an unconsolidated affiliate of PECO.

On September 30, 2005, Moody's Investors Service placed ComEd's ratings under review for a possible downgrade due to the adverse regulatory environment in Illinois as described in Note 4 of Exelon's Notes to Consolidated Financial Statements. On December 15, 2005, Moody's Investor Service downgraded the long-term debt and preferred stock ratings of ComEd. ComEd's short-term rating for commercial paper was not downgraded. All of ComEd's ratings remain on review for possible downgrade. The ratings outlook for Exelon, Generation and PECO were unchanged. On October 3, 2005, Standard & Poor's Rating Services (S&P) lowered its corporate credit ratings and senior unsecured debt ratings on Exelon and its subsidiaries due to the adverse regulatory environment in Illinois as described in Note 4 of Exelon's Notes to Consolidated Financial Statements. The short-term debt ratings and senior secured ratings were unaffected. The ratings on all Exelon affiliates remain on CreditWatch with negative implications pending the completion of the merger with PSEG. On January 9, 2006, Fitch Ratings revised the rating outlook on the long-term debt and preferred stock of ComEd to negative from stable. The rating outlooks on all other Exelon affiliates remain stable. None of Exelon's borrowings is subject to default or prepayment as a result of a downgrading of securities although such a downgrading could increase fees and interest charges under Exelon's credit facilities.

A security rating is not a recommendation to buy, sell or hold securities and may be subject to revision or withdrawal at any time by the assigning rating agency.

As part of the normal course of business, Generation routinely enters into physical or financially settled contracts for the purchase and sale of capacity, energy, fuels and emissions allowances. These contracts either contain express provisions or otherwise permit its counterparties and Generation 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 Exelon or 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 its 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, the obligation to supply the collateral requested will be a function of the facts and circumstances of Exelon or Generation's situation at the time of the demand. If Exelon can reasonably claim that it is willing and financially able to perform its obligations, it may be possible to successfully argue that no collateral should be posted or that only an amount equal to two or three months of future payments should be sufficient.

Shelf Registrations

As of December 31, 2005, Exelon, ComEd and PECO had current shelf registration statements for the sale of $300 million, $555 million and $550 million, respectively, of securities that were effective with the SEC. The ability of Exelon, ComEd or PECO to sell securities off its 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, the current financial condition of the company, its securities ratings and market conditions.

Regulatory Restrictions

The issuance of long-term debt or equity securities by ComEd requires the prior authorization of the ICC. The issuance by PECO of long-term debt or equity securities requires the prior authorization of the PAPUC. ComEd and PECO normally obtain the required approvals on a periodic basis to cover their financing needs or in connection with a specific financing.

Under PUHCA, the SEC had financing jurisdiction over ComEd's and PECO's short-term financings and all of Generation's and Exelon's financings. As a result of the repeal of PUHCA, effective February 8, 2006, the SEC's financing jurisdiction under PUHCA for ComEd's and PECO's short-term financings and Generations financings reverted to FERC and Exelon's financings are no longer subject to regulatory approvals.

On February 7, 2006, FERC issued a blanket authorization for the acquisition of securities pursuant to the Exelon Utility Money Pool Agreement, subject to the same limits and reporting requirements imposed by the SEC under PUHCA. The FERC order is effective for one year instead of the usual two-year effective period. The one-year period will allow Exelon to maintain the status quo while FERC determines whether on rehearing to amend its rules to make future applications unnecessary (e.g., blanket authorizations for all money pool transactions). Because PSE&G was not an applicant requesting participation in the Exelon Utility Money Pool, the FERC denied Exelon's request to allow PSE&G to participate in the Exelon Utility Money Pool post-merger.

On December 7, 2005, ComEd and PECO filed applications for short-term financing authority with the FERC in the amounts of $2.5 billion and $1.5 billion, respectively. In February 2006, ComEd and PECO received orders from the FERC approving their requests, effective February 8, 2006 through December 31, 2007.

Generation currently has blanket financing authority that it received from FERC in November 2000 that became effective again with the repeal of PUHCA. If the FERC proceeding relating to Generation's market-based rate authority results in revocation of that authority, Generation's blanket financing authority may also be revoked. If that financing authority is revoked, it is possible that the revocation of financing authority would be effective prospectively. It is also possible that the revocation of financing authority might be retroactive to October 2, 2005. FERC has adopted regulations that would grandfather prior SEC approvals of financings at a company's election. The FERC regulations require that companies intending to issue securities in reliance on their SEC financing orders file with FERC a copy of their SEC financing order within 30 days after the effective date of PUHCA repeal. In light of the potential uncertainty relating to the possible revocation of FERC's blanket financing authority, Exelon has filed its SEC financing order with the FERC. The SEC financing order contains certain terms, limits, and reporting requirements which Exelon continues to review to determine the extent to which it would be subject to such conditions.

Under applicable law, ComEd, PECO and Generation can pay dividends only from retained, undistributed or current earnings. A significant loss recorded at ComEd, PECO or Generation may limit the dividends that these companies can distribute to Exelon. At December 31, 2005, Exelon had retained earnings of $3.2 billion, including ComEd's retained deficit of $(81) million consisting of $1,099 million of retained earnings appropriated for future dividends offset by an unappropriated retained deficit of ($1,180) million, PECO's retained earnings of $649 million and Generation's undistributed earnings of $1,002 million.

Investments in Synthetic Fuel-Producing Facilities

Exelon, through three wholly owned subsidiaries, has investments in synthetic fuel-producing facilities. Section 45k (formerly Section 29) of the Internal Revenue Code provides tax credits for the sale of synthetic fuel produced from coal. However, Section 45k contains a provision under which credits are phased out (i.e., eliminated) in the event crude oil prices for a year exceed certain thresholds.

The following table (in dollars) provides the estimated phase-out range for 2006 and 2007 based on the per barrel price of oil. The table also contains the annual average New York Mercantile Exchange, Inc. index (NYMEX) future prices per barrel at December 31, 2005 for 2006 and 2007.

	Estimated 2006	Estimated 2007
Beginning of Phase-Out Range [(a)]	$59	$61
End of Phase-Out Range [(a)]	75	76
Annual Average NYMEX Future Price	65	66

(a) Estimated phase-out ranges are calculated using inflation rates published by the IRS after year-end. The inflation rate used by Exelon to estimate the 2006 and 2007 phase-out ranges was 2%.

Based on the 2006 and 2007 NYMEX futures prices at December 31, 2005, Exelon estimates there will be a phase-out of tax credits of 38% and 36% in 2006 and 2007, respectively. This would decrease Exelon's net income as compared to 2005 by as much as $38 million and $36 million in 2006 and 2007, respectively. These estimates can change significantly due to the volatility in oil prices.

The purchase price for Exelon's investments in synthetic fuel-producing facilities is comprised of fixed and variable components. The fixed component is in the form of a non-recourse note that requires nonrefundable quarterly payments of principal and interest to sellers. The variable component is based on the value of the estimated tax credits that will be allocated to Exelon. Exelon's subsidiaries are also required to make capital contributions based on the allocated amount of tax credits to the operators to fund the operating losses.

Given the refundable nature of the variable components of the purchase price and operating losses paid to the sellers and operators of the facilities, respectively, Exelon's results of operations and cash flows are not anticipated to be affected by a phase-out of tax credits due to a rise in crude oil prices to the extent of these variable components (notwithstanding the differences in the timing of refundable variable payments and the associated refunds). However, Exelon's results of operations and cash flows could be negatively affected to the extent that Exelon is not allocated enough tax credits to cover the principal and interest payments due on the non-recourse notes representing the non-refundable fixed component of the purchase price.

Absent any efforts to mitigate market price exposure, a phase-out could result in the reduction of the non-operating net income generated by the investments and could result in an estimated after-tax non-operating loss of up to $70 million per year in the event all tax credits are completely eliminated, exclusive of any impacts related to the intangible assets. In 2005, Exelon and Generation entered into certain derivatives in the normal course of trading operations to economically hedge a portion of this exposure. These derivatives could result in after-tax cash proceeds to Exelon of up to $42 million and $42 million in 2006 and 2007, respectively, in the event the tax credits are completely phased out. See Note 12 of Exelon's Notes to the Consolidated Financial Statements for further information regarding Exelon's investments in synthetic fuel-producing facilities.

Contractual Obligations and Off-Balance Sheet Arrangements

The following table summarizes Exelon's future estimated cash payments under existing contractual obligations, including payments due by period.

	Total	Payment due within 2006	2007-2008	2009-2010	Due 2011 and beyond
Long-term debt	$ 8,140	$ 405	$1,125	$ 669	$ 5,941
Long-term debt to financing trusts	4,508	507	1,950	1,506	545
Interest payments on long-term debt [(a)]	4,199	697	767	691	2,044
Interest payments on long-term debt to financing trusts [(a)]	1,588	267	399	173	749
Capital leases	46	2	4	4	36
Operating leases	766	55	108	92	511
Purchase power obligations	8,800	2,124	1,672	1,258	3,746
Fuel purchase agreements	4,299	754	1,235	933	1,377
Other purchase obligations [(b)]	987	211	283	275	218
Chicago agreement [(c)]	42	6	12	12	12
Regulatory commitments	10	10	—	—	—
Spent nuclear fuel obligation	906	—	—	—	906
Obligation to minority shareholders	46	3	5	5	33
Pension ERISA minimum funding requirement	11	11	—	—	—
Asset retirement obligations [(d)]	4,157	66	13	12	4,066
Total contractual obligations	$38,505	$5,118	$7,573	$5,630	$20,184

(a) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2005 and do not reflect anticipated future refinancing, early redemptions or debt issuances. Variable rate interest obligations are estimated based on rates as of December 31, 2005. The contributions will be funded in part by additional debt anticipated to be issued in 2005. Estimated future payments associated with the anticipated debt issuance have not been included in the table above.

(b) Commitments for services, materials and information technology.

(c) On February 20, 2003, ComEd entered into separate agreements with Chicago and with Midwest Generation (Midwest Agreement). Under the terms of the agreement with Chicago, ComEd will pay Chicago $60 million over ten years to be relieved of a requirement, originally transferred to Midwest Generation upon the sale of ComEd's fossil stations in 1999, to build a 500-MW generation facility.

(d) Represents the present value of Generation's obligation to decommission nuclear plants and ComEd's, PECO's and Generation's conditional AROs recorded in connection with the adoption of FIN 47. AROs associated with assets that have been fully depreciated but which are still in service have been reflected as payments due in 2006.

For additional information about:

- regulatory commitments, see Note 4 of Exelon's Notes to Consolidated Financial Statements.
- commercial paper, see Note 10 of Exelon's Notes to Consolidated Financial Statements.
- long-term debt, see Note 11 of Exelon's Notes to Consolidated Financial Statements.
- capital lease obligations, see Note 11 of Exelon's Notes to Consolidated Financial Statements.
- the spent nuclear fuel and decommissioning obligations, see Note 13 of Exelon's Notes to Consolidated Financial Statements.
- the contribution required to Exelon's pension plans to satisfy ERISA minimum funding requirements, see Note 15 of Exelon's Notes to Consolidated Financial Statements.
- operating leases, energy commitments and fuel purchase agreements, see Note 20 of Exelon's Notes to Consolidated Financial Statements.

- the obligation to minority shareholders, see Note 20 of Exelon's Notes to Consolidated Financial Statements.
- asset retirement obligations, see Notes 13 and 14 of Exelon's Notes to Consolidated Financial Statements.

Mystic Development, LLC (Mystic), a former affiliate of Exelon New England, has a long-term agreement through January 2020 with Distrigas of Massachusetts Corporation (Distrigas) for gas supply, primarily for the Boston Generating units. Under the agreement, gas purchase prices from Distrigas are indexed to the New England gas markets. Exelon New England has guaranteed Mystic's financial obligations to Distrigas under the long-term supply agreement. Exelon New England's guarantee to Distrigas remained in effect following the transfer of ownership interest in Boston Generating in May 2004. Under FIN 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness to Others (FIN 45)," approximately $14 million was included as a liability within the Consolidated Balance Sheets of Exelon as of December 31, 2005 related to this guarantee. The terms of the guarantee do not limit the potential future payments that Exelon New England could be required to make under the guarantee.

Generation has an obligation to decommission its nuclear power plants. NRC regulations require that licensees of nuclear generating facilities demonstrate reasonable assurance that funds will be available in certain minimum amounts at the end of the life of the facility to decommission the facility. Based on estimates of decommissioning costs for each of the nuclear facilities in which Generation has an ownership interest, the ICC permits ComEd, and the PAPUC permits PECO, to collect from their customers and deposit in nuclear decommissioning trust funds maintained by Generation amounts which, together with earnings thereon, will be used to decommission such nuclear facilities. Generation also maintains nuclear decommissioning trust funds for each of the AmerGen units. Upon adoption of SFAS No. 143, Generation was required to re-measure its decommissioning liabilities at fair value and recorded an asset retirement obligation of $2.4 billion on January 1, 2003. Increases in the asset retirement obligation to decommission nuclear generating facilities resulting from the passage of time are recorded as operating and maintenance expense. Increases in the asset retirement obligation resulting from a remeasurement are recorded with a corresponding ARC, which is a component of property, plant and equipment. At December 31, 2005, the asset retirement obligation recorded within Generation's Consolidated Balance Sheets related to its nuclear-fueled generating facilities was approximately $4 billion. Decommissioning expenditures are expected to occur primarily after the plants are retired. Based on current licenses and anticipated renewals, decommissioning expenditures for plants in operation are currently estimated to begin after 2029. To fund future decommissioning costs, Generation held approximately $5.6 billion of investments in trust funds, including net unrealized gains and losses, at December 31, 2005. See Note 13 of Exelon's Notes to Consolidated Financial Statements for further discussion of Generation's decommissioning obligation.

See Note 20 of Exelon's Notes to Consolidated Financial Statements for discussion of Exelon's commercial commitments as of December 31, 2005.

Refund Claims

ComEd and PECO have several pending tax refund claims seeking acceleration of certain tax deductions and additional tax credits. ComEd and PECO are unable to estimate the ultimate outcome of these refund claims and will account for any amounts received in the period the matters are settled with the IRS and state taxing authorities.

ComEd and PECO had entered into several agreements with a tax consultant related to the filing of these refund claims with the IRS. ComEd and PECO previously made refundable prepayments to the tax consultants of $11 million and $5 million, respectively. The fees for these agreements are contingent upon a successful outcome of the claims and are based upon a percentage of the refunds recovered from the IRS if any. These potential tax benefits and associated fees could be material to the financial position, results of operations and cash flows of ComEd and PECO. A portion of ComEd's tax benefits, including any associated interest for periods prior to the merger among PECO, Unicom Corporation (Unicom), the former parent company of ComEd, and Exelon (PECO / Unicom Merger) would be recorded as a reduction of goodwill pursuant to a reallocation of the PECO / Unicom Merger purchase price. ComEd and PECO cannot predict the timing of the final resolution of these refund claims.

In 2004, the IRS granted preliminary approval for one of ComEd's refund claims and final approval was obtained in the first quarter of 2005. The refund and associated interest have been recorded in the financial statements. Approximately $14 million of tax and interest benefit received in the second quarter of 2005 has been reflected in the financial statements of which $12 million ($9 million after tax) was recorded to goodwill under the provisions of EITF Issue 93-7, "Uncertainties Related to Income Taxes in a Purchase Business Combination." As a result, ComEd recorded consulting expenses of $5 million (pre-tax) in 2004.

Based on negotiations with the IRS during the first half of 2005, PECO believed it would receive a tax refund related to one of its claims and recorded a $6 million (pre-tax) charge related to expected consulting fees during the first quarter of 2005. However, as the result of a recent unfavorable tax court decision involving another utility related to a similar type of refund claim, PECO no longer believes payment of the consulting fees is probable and reversed the $6 million (pre-tax) charge during the third quarter 2005. PECO is unable to predict the final impact of its future negotiations with the IRS on this matter.

Variable Interest Entities

Sithe. As of December 31, 2004, Generation was a 50% owner of Sithe. In accordance with FIN 46-R, Generation consolidated Sithe within its financial statements as of March 31, 2004. The determination that Sithe qualified as a variable interest entity and that Generation was the primary beneficiary under FIN 46-R required analysis of the economic benefits accruing to all parties pursuant to their ownership interests supplemented by management's judgment. See Note 3 of Exelon's Notes to Consolidated Financial Statements for a discussion of the sale of Generation's entire interest in Sithe that was completed on January 31, 2005.

Financing Trusts of ComEd and PECO. During June 2003, PECO issued $103 million of subordinated debentures to PECO Trust IV in connection with the issuance by PECO Trust IV of $100 million of preferred securities. Effective July 1, 2003, PECO Trust IV was deconsolidated from the financial statements of PECO in conjunction with FIN 46. The $103 million of subordinated debentures issued by PECO to PECO Trust IV was recorded as long-term debt to financing trusts within the Consolidated Balance Sheets.

Effective December 31, 2003, ComEd Financing II, ComEd Financing III, ComEd Funding, LLC, ComEd Transitional Funding Trust, PECO Trust III and PETT were deconsolidated from the financial statements of Exelon in conjunction with the adoption of FIN 46-R. Amounts of $1.3 billion and $3.1 billion, respectively, owed by ComEd and PECO to these financing trusts were recorded as long-term debt to ComEd Transitional Funding Trust and PETT and long-term debt to financing trusts within the Consolidated Balance Sheets as of December 31, 2005. See Other Subsidiaries of ComEd and PECO with Publicly Held Securities in Part I, ITEM 1 of Exelon's 2005 Form 10-K for further discussion of the nature, purpose and history of Exelon's involvement with these financing trusts.

PECO Accounts Receivable Agreement

PECO is party to an agreement with a financial institution under which it can sell or finance with limited recourse an undivided interest, adjusted daily, in up to $225 million of designated accounts receivable until November 2010 based on the November 2005 amendment to this agreement. At December 31, 2005, PECO had sold a $225 million interest in accounts receivable, consisting of a $195 million interest in accounts receivable, which PECO accounted for as a sale under SFAS No. 140, "Accounting for Transfers and Servicing of Financial Assets and Extinguishment of Liabilities—a Replacement of FASB Statement No. 125," (SFAS No. 140) and a $30 million interest in special agreement accounts receivable, which PECO accounted for as a long-term note payable and reflected on the consolidated balance sheets as long-term debt due within one year. At December 31, 2004, PECO had sold a $225 million interest in accounts receivable, consisting of a $179 million interest in accounts receivable, which PECO accounted for as a sale under SFAS No. 140, and a $46 million interest in special agreement accounts receivable, which PECO accounted for as a long-term note payable and reflected on the consolidated balance sheets as long-term debt due within one year. PECO must continue to service these receivables and must maintain the level of the accounts receivable at $225 million. If PECO fails to maintain that level, the cash that would otherwise be received by PECO under this program must be held in escrow until the level is met. At December 31, 2005 and 2004, PECO met this requirement and was not required to make any cash deposit.

Nuclear Insurance Coverage

Generation carries property damage, decontamination and premature decommissioning insurance for each station loss resulting from damage to Generation's nuclear plants, subject to certain exceptions. Additionally, Generation carries business interruption insurance in the event of a major accidental outage at a nuclear station. Finally, Generation participates in the American Nuclear Insurers Master Worker Program, which provides coverage for worker tort claims filed for bodily injury caused by a nuclear energy accident. See Note 20 of Exelon's Notes to Consolidated Financial Statements for further discussion of nuclear insurance. For its types of insured losses, Generation is self-insured to the extent that losses are within the policy deductible or exceed the amount of insurance maintained. Such losses could have a material adverse effect on Exelon and Generation's financial condition and their results of operations and cash flows.

New Accounting Pronouncements

See Note 1 of Exelon's Notes to Consolidated Financial Statements for information regarding new accounting pronouncements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Exelon is 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 derivative activity and risk exposures. The RMC is chaired by the chief risk officer and includes the chief financial officer, general counsel, treasurer, vice president of corporate planning, 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 derivative and risk management activities.

Commodity Price Risk (Exelon, ComEd and Generation)

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. Commodity price risk is associated with price movements resulting from changes in supply and demand, fuel costs, market liquidity, weather, governmental regulatory and environmental policies, and other factors. Exelon seeks to mitigate its commodity price risk through the purchase and sale of electric capacity, energy and fossil fuels including oil, gas, coal and emission allowances. Within Exelon, Generation is primarily exposed to commodity price risk with ComEd having modest exposure due to the need to purchase ancillary services and the commodity price risk in relation to the CTC revenues collected from customers.

Generation

Generation's energy contracts are accounted for under SFAS No. 133. Non-trading contracts qualify for the normal purchases and normal sales exemption to SFAS No. 133, which is discussed in Critical Accounting Policies and Estimates. Energy contracts that do not qualify for the normal purchases and normal sales exception are recorded as assets or liabilities on the balance sheet at fair value. Changes in the fair value of qualifying hedge contracts are recorded in other comprehensive income (OCI), and gains and losses are recognized in earnings when the underlying transaction occurs. Changes in the derivatives recorded at fair value are recognized in earnings unless specific hedge accounting criteria are met and they are designated as cash-flow hedges, in which case those changes are recorded in OCI, and gains and losses are recognized in earnings when the underlying transaction occurs. Changes in the fair value of derivative contracts that do not meet the hedge criteria under SFAS No. 133 or are not designated as such are recognized in current earnings.

Normal Operations and Hedging Activities. Electricity available from Generation's owned or contracted generation supply in excess of Generation's obligations to customers, including ComEd's and PECO's retail load, is sold into the wholesale markets. To reduce price risk caused by market fluctuations, Generation enters into physical contracts as well as derivative contracts, including forwards, futures, swaps, and options, with approved counterparties to hedge anticipated exposures. The maximum length of time over which cash flows related to energy commodities are currently being cash-flow hedged is three years. Generation has an estimated 88% hedge ratio in 2006 for its energy marketing portfolio. This hedge ratio represents the percentage of its forecasted aggregate annual economic generation supply that is committed to firm sales, including sales to ComEd's and PECO's retail load. ComEd's and PECO's retail load assumptions are based on forecasted average demand. The hedge ratio is not fixed and will vary from time to time depending upon market conditions, demand, energy market option volatility and actual loads. During peak periods, Generation's amount hedged declines to meet its energy and capacity commitments to ComEd and PECO. Market price risk exposure is the risk of a change in the value of unhedged positions. Absent any efforts to mitigate market price exposure, the estimated market price exposure for Generation's unhedged non-trading portfolio associated with a ten percent reduction in the annual average around-the-clock market price of electricity is approximately a $61 million decrease in net income. This sensitivity assumes an 88% hedge ratio and that price changes occur evenly throughout the year and across all markets. The sensitivity also assumes a static portfolio. Generation expects to actively manage its portfolio to mitigate market price exposure. 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.

In connection with the 2001 corporate restructuring, Generation entered into a PPA, as amended, with ComEd under which Generation has agreed to supply all of ComEd's load obligations through 2006. At times, ComEd's load obligations are greater than the capacity of Generation's owned generating units in the ComEd region. As such, Generation procures power through purchase power and lease agreements and has contracted for access to additional generation through bilateral long-term PPAs. In 2004, Generation retained 3,858 MWs of capacity under the terms of three then-existing PPAs with Midwest Generation, LLC (Midwest Generation). Generation's contract to purchase power from Midwest Generation expired at the end of 2004. As a result, Generation's exposure to market price movements in the ComEd region in 2005 increased compared to 2004 due in part to the expiration of the Midwest Generation contract. Consequently, after 2004, Generation must procure the necessary power for ComEd through market purchases and other means to the extent not provided by Generation's own generating facilities.

Following the expiration of the Illinois transition period and end of PPA between Generation and ComEd in 2006, all of Generation's supply in the ComEd region will be available for sale into the wholesale markets and exposed to changes in market prices.

Proprietary Trading Activities. Generation began to use financial contracts for proprietary trading purposes in 2001. Proprietary trading includes all contracts entered into purely to profit from market price changes as opposed to hedging an exposure. These activities are accounted for on a mark-to-market basis. The proprietary trading activities are a complement to Generation's energy marketing portfolio but represent a very small portion of Generation's overall energy marketing activities. For example, the limit on open positions in electricity for any forward month represents less than one percent of Generation's owned and contracted supply of electricity. Generation expects this level of proprietary trading activity to continue in the future. Trading portfolio activity for the year ended December 31, 2005 resulted in a gain of $17 million (before income taxes), which represented a net unrealized mark-to-market gain of $15 million and realized gain of $2 million. Generation uses a 95% confidence interval, one day holding period, one-tailed statistical measure in calculating its Value-at-Risk (VaR). The daily VaR on proprietary trading activity averaged $90,000 of exposure over the last 18 months. Because of the relative size of the proprietary trading portfolio in comparison to Generation's total gross margin from continuing operations for year ended December 31, 2005 of $4,564 million, Generation has not segregated proprietary trading activity in the following tables. The trading portfolio is subject to a risk management policy that includes stringent risk management limits, including volume, stop-loss and value-at-risk limits to manage exposure to market risk. Additionally, the Exelon risk management group and Exelon's RMC monitor the financial risks of the proprietary trading activities.

Trading and Non-Trading Marketing Activities. The following detailed presentation of Generation's trading and non-trading marketing activities at Generation is included to address the recommended disclosures by the energy industry's Committee of Chief Risk Officer (CCRO).

The following table provides detail on changes in Generation's mark-to-market net asset or liability balance sheet position from January 1, 2004 to December 31, 2005. 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 hedging activities that are recorded in accumulated OCI on the Consolidated Balance Sheets.

	Total
Total mark-to-market energy contract net liabilities at January 1, 2004	$(216)
Total change in fair value during 2004 of contracts recorded in earnings	158
Reclassification to realized at settlement of contracts recorded in earnings	(197)
Reclassification to realized at settlement from OCI	475
Effective portion of changes in fair value—recorded in OCI	(512)
Purchase/sale/disposal of existing contracts or portfolios subject to mark-to-market	147
Total mark-to-market energy contract net liabilities at December 31, 2004 [(a)]	(145)
Total change in fair value during 2005 of contracts recorded in earnings	108
Reclassification to realized at settlement of contracts recorded in earnings	(105)
Reclassification to realized at settlement from OCI	583
Effective portion of changes in fair value—recorded in OCI	(879)
Purchase/sale/disposal of existing contracts or portfolios subject to mark-to-market	(102)
Total mark-to-market energy contract net liabilities at December 31, 2005	$(540)

(a) Includes a $39 million liability related to Sithe and the related mark-to-market expense which were reclassified to discontinued operations.

The following table details the balance sheet classification of the mark-to-market energy contract net assets (liabilities) recorded as of December 31, 2005 and 2004:

	December 31, 2005	December 31, 2004
Current assets	$ 916	$ 403
Noncurrent assets	286	373
Total mark-to-market energy contract assets	1,202	776
Current liabilities	(1,282)	(598)
Noncurrent liabilities	(460)	(323)
Total mark-to-market energy contract liabilities	(1,742)	(921)
Total mark-to-market energy contract net liabilities	$ (540)	$(145)

The majority of Generation's contracts are non-exchange-traded contracts valued using prices provided by external sources, primarily price quotations available through brokers or over-the-counter, on-line exchanges. Prices reflect the average of the bid-ask mid-point prices obtained from all sources that Generation believes provide the most liquid market for the commodity. The terms for which such price information is available varies by commodity, region and product. The remainder of the assets represents contracts for which external valuations are not available, primarily option contracts. These contracts are valued using the Black model, an industry standard option valuation model. The fair values in each category reflect the level of forward prices and volatility factors as of December 31, 2005 and may change as a result of changes in these factors. Management uses its best estimates to determine the fair value of commodity and derivative contracts it holds and sells. These estimates consider various factors including closing exchange and over-the-counter price quotations, time value, volatility factors and credit exposure. It is possible, however, that future market prices could vary from those used in recording assets and liabilities from energy marketing and trading activities and such variations could be material.

The following table, which presents maturity and source of fair value of mark-to-market energy contract net liabilities, provides two fundamental pieces of information. First, the table provides the source of fair value used in determining the carrying amount of Generation's total mark-to-market asset or liability. Second, this table provides the maturity, by year, of Generation's net assets/liabilities, giving an indication of when these mark-to-market amounts will settle and either generate or require cash.

	Maturities within						
(in millions)	2006	2007	2008	2009	2010	2011 and Beyond	Total Fair Value
Normal Operations, qualifying cash-flow hedge contracts [(a)]:							
Actively quoted prices	$ 2	$ 1	$—	$—	$—	$—	$ 3
Prices provided by other external sources	(388)	(134)	(2)	—	—	—	(524)
Total	$(386)	$(133)	$ (2)	$—	$—	$—	$(521)
Normal Operations, other derivative contracts [(b)]:							
Actively quoted prices	$ 85	$ (57)	$ 5	$—	$—	$—	$ 33
Prices provided by other external sources	(43)	25	(5)	—	—	—	(23)
Prices based on model or other valuation methods	(24)	(5)	—	—	—	—	(29)
Total	$ 18	$ (37)	$—	$—	$—	$—	$ (19)

(a) Mark-to-market gains and losses on contracts that qualify as cash-flow hedges are recorded in other comprehensive income.

(b) Mark-to-market gains and losses on other non-trading and trading derivative contracts that do not qualify as cash-flow hedges are recorded in earnings.

The table below provides details of effective cash-flow hedges under SFAS No. 133 included in the balance sheet as of December 31, 2005. The data in the table gives an indication of the magnitude of SFAS No. 133 hedges Generation has in place; however, since under SFAS No. 133 not all hedges are recorded in OCI, the table does not provide an all-encompassing picture of Generation's hedges. The table also includes a roll-forward of accumulated OCI related to cash-flow hedges for the years ended December 31, 2005 and December 31, 2004, providing insight into the drivers of the changes (new hedges entered into during the period and changes in the value of existing hedges). Information related to energy merchant activities is presented separately from interest-rate hedging activities.

	Total Cash-Flow Hedge OCI Activity, Net of Income Tax		
(in millions)	Power Team Normal Operations and Hedging Activities	Interest-Rate and Other Hedges	Total Cash-Flow Hedges
Accumulated OCI derivative loss at January 1, 2004	$(133)	$(16)	$(149)
Changes in fair value	(312)	17	(295)
Disposal of existing Boston Generating contracts	16	—	16
Reclassifications from OCI to net income	290	—	290
Exelon Energy Company opening balance	2	—	2
Sithe Energies, Inc. opening balance	—	(10)	(10)
Accumulated OCI derivative loss at December 31, 2004	(137)	(9)	(146)
Changes in fair value	(533)	5	(528)
Reclassifications from OCI to net income	356	—	356
Accumulated OCI derivative loss at December 31, 2005	$(314)	$ (4)	$(318)

ComEd

ComEd has exposure to commodity price risk in relation to revenue collected from customers who elect to purchase energy from an alternative electric supplier or the ComEd PPO. Revenues collected from customers electing the PPO include commodity charges at market-based prices and CTC revenues which are calculated to provide the customer with a credit for the market price for electricity. Because the change in revenues from customers electing the PPO is significantly offset by the change in CTC revenues, ComEd does not believe that its exposure to such a market price decrease would be material.

ComEd's CTC revenues are also collected from customers who elect to purchase energy from an alternative electric supplier. ComEd's CTC rates are reset once a year in the spring, and customers can elect to lock in their CTC rates for a one or multiple year terms. ComEd anticipates that CTC revenues will range from $35 million to $50 million in 2006. Under current Illinois law, no CTCs will be collected after 2006.

ComEd also has exposure to commodity price risk in relation to ancillary services that are purchased from PJM. These services are not provided for in the current PPA between Generation and ComEd.

Credit Risk (Exelon, ComEd, PECO and Generation)

ComEd and PECO

Credit risk for ComEd and PECO is managed by credit and collection policies which are consistent with state regulatory requirements. ComEd and PECO are each currently obligated to provide service to all electric customers within their respective franchised territories. For the year ended December 31, 2005, ComEd's ten largest customers represented approximately 3.5% of its electric revenues and PECO's ten largest customers represented approximately 7.6% of its retail electric and gas revenues. ComEd and PECO record a provision for uncollectible accounts, based upon historical experience and third-party studies, to provide for the potential loss from nonpayment by these customers.

Under the Competition Act, licensed entities, including alternative electric suppliers, may act as agents to provide a single bill and provide associated billing and collection services to retail customers located in PECO's retail electric service territory. Currently, there are no third parties providing billing of PECO's charges to customers or advanced metering; however, if this occurs, PECO would be subject to credit risk related to the ability of the third parties to collect such receivables from the customers.

Generation

Generation has credit risk associated with counterparty performance on energy contracts which includes, but is not limited to, the risk of financial default or slow payment. Generation manages counterparty credit risk through established policies, including counterparty credit limits, and in some cases, requiring deposits and letters of credit to be posted by certain counterparties. Generation's counterparty credit limits are based on a scoring model that considers a variety of factors, including leverage, liquidity, profitability, credit ratings and risk management capabilities. Generation has entered into payment netting agreements or enabling agreements that allow for payment netting with the majority of its large counterparties, which reduce Generation's exposure to counterparty risk by providing for the offset of amounts payable to the counterparty against amounts receivable from the counterparty. The 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, net of collateral, as of December 31, 2005 and 2004. They further delineate that exposure by the credit rating of the counterparties and provide guidance on the concentration of credit risk to individual counterparties and an indication of the maturity of a company's credit risk by credit rating of the counterparties. The figures in the tables below do not include sales to Generation's affiliates or exposure through ISOs which are discussed below.

Rating as of December 31, 2005 (a)	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	$472	$ 53	$419	2	$147
Non-investment grade	60	11	49	—	—
No external ratings					
Internally rated—investment grade	41	—	41	—	—
Internally rated—non-investment grade	38	—	38	—	—
Total	$611	$ 64	$547	2	$147

(a) This table does not include accounts receivable exposure.

Rating as of December 31, 2004 (a)	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	$151	$ 33	$118	—	$—
Non-investment grade	98	20	78	1	63
No external ratings					
Internally rated—investment grade	13	—	13	—	—
Internally rated—non-investment grade	3	—	3	—	—
Total	$265	$ 53	$212	1	$ 63

(a) This table does not include accounts receivable exposure.

Rating as of December 31, 2005 (a)	Maturity of Credit Risk Exposure			
	Less than 2 Years	2-5 Years	Exposure Greater than 5 Years	Total Exposure Before Credit Collateral
Investment grade	$472	$—	$—	$472
Non-investment grade	56	4	—	60
No external ratings				
Internally rated—investment grade	38	3	—	41
Internally rated—non-investment grade	17	14	7	38
Total	$583	$ 21	$ 7	$611

(a) This table does not include accounts receivable exposure.

Collateral. As part of the normal course of business, Generation routinely enters into physical or financially settled contracts for the purchase and sale of capacity, energy, fuels and emissions allowances. 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, the obligation to supply the collateral requested will be a function of the facts and circumstances of the situation at the time of the demand. If Generation can reasonably claim that it is willing and financially able to perform its obligations, it may be possible to successfully argue that no collateral should be posted or that only an amount equal to two or three months of future payments should be sufficient.

ISOs. Generation participates in the following established, real-time energy markets that are administered by ISOs: PJM, ISO New England, New York ISO, MISO, Southwest Power Pool, Inc. and the Electric Reliability Council of Texas. In these areas, power is traded through bilateral agreements between buyers and sellers and on the spot markets that are operated by the ISOs. 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 the ISOs, the ISO maintains financial assurance policies that are established and enforced by those administrators. The credit policies of the 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 Generation's financial condition, results of operations or net cash flows.

Exelon

Exelon's consolidated balance sheets included a $507 million net investment in direct financing leases as of December 31, 2005. The investment in direct financing leases represents future minimum lease payments due at the end of the thirty-year lives of the leases of $1,492 million, less unearned income of $985 million. The future minimum lease payments are supported by collateral and credit enhancement measures including letters of credit, surety bonds and credit swaps issued by high credit quality financial institutions. Management regularly evaluates the credit worthiness of Exelon's counterparties to these direct financing leases.

Interest-Rate Risk (Exelon, ComEd, PECO and Generation)

Variable Rate Debt. The Registrants use a combination of fixed-rate and variable-rate debt to reduce interest-rate exposure. The Registrants also use interest-rate swaps when deemed appropriate to adjust exposure based upon market conditions. Additionally, the Registrants use forward-starting interest-rate swaps and treasury rate locks to lock in interest-rate levels in anticipation of future financings. These strategies are employed to achieve a lower cost of capital. As of December 31, 2005, a hypothetical 10% increase in the interest rates associated with variable-rate debt would result in a $3 million, $1 million and $2 million decrease in Exelon's, ComEd's and Generation's, respectively, pre-tax earnings. A hypothetical 10% increase in the interest rates associated with variable-rate debt would result in a decrease in pre-tax earnings of less than $1 million at PECO.

Fair-Value Hedges. At December 31, 2005, ComEd had interest-rate swaps designated as fair-value hedges in the aggregate notional amount of $240 million. At December 31, 2005, these interest-rate swaps had an aggregate fair market value of $(1) million based on the present value difference between the contract and market rates at December 31, 2005. If these derivative instruments had been terminated at December 31, 2005, this estimated fair value represents the amount ComEd would pay the counterparties. On January 17, 2006, ComEd settled these swaps and paid $1 million.

The aggregate fair value of ComEd's interest-rate swaps designated as fair-value hedges that would have resulted from a hypothetical 50 basis point decrease in the spot yield at December 31, 2005 is estimated to be a favorable impact to ComEd of $5 million. If these derivative instruments had been terminated at December 31, 2005, this estimated fair value represents the amount counterparties would pay ComEd.

The aggregate fair value of ComEd's interest-rate swaps designated as fair-value hedges that would have resulted from a hypothetical 50 basis point increase in the spot yield at December 31, 2005 is estimated to be a favorable impact to the counterparties of $7 million. If these derivative instruments had been terminated at December 31, 2005, this estimated fair value represents the amount ComEd would pay the counterparties.

Cash-Flow Hedges. During 2005, ComEd entered into five forward-starting interest-rate swaps in the aggregate notional amount of $325 million to lock in interest-rate levels in anticipation of a future financing. At the time of the swap trades, the debt issuance that these swaps were hedging was considered probable; therefore, ComEd accounted for these interest-rate swap transactions as cash-flow hedges. However, in September 2005, the future financing was postponed indefinitely and consequently, ComEd unwound the $325 million forward-starting interest-rate swaps and paid the counterparties approximately $15 million. As a result, Exelon and ComEd recognized a pre-tax loss of $15 million which was included in other, net within the Consolidated Statements of Income. In addition, during 2005, Exelon settled interest-rate swaps in the aggregate notional amount of $1.5 billion and recorded pre-tax losses of $39 million which will be recorded as additional interest expense over the remaining life of the related debt.

Equity Price Risk (Exelon and Generation)

Generation maintains trust funds, as required by the NRC, to fund certain costs of decommissioning Generation's nuclear plants. As of December 31, 2005, 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 nuclear decommissioning trust fund investment policy. A hypothetical 10% increase in interest rates and decrease in equity prices would result in a $391 million reduction in the fair value of the trust assets. See Defined Benefit Pension and Other Postretirement Welfare Benefits in the Critical Accounting Estimates section for information regarding the pension and other postretirement benefit trust assets.

CERTIFICATIONS

The CEO of Exelon has made the required annual certifications for 2005 to the New York Stock Exchange and the Philadelphia Stock Exchange that Exelon is in compliance with the listing standards of those exchanges. The CEO and CFO have filed with the SEC all required certifications under section 302 of the Sarbanes-Oxley Act of 2002. These certifications are filed as Exhibits 31-1 and 31-2 to Exelon's 2005 Form 10-K.

FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Management's Report on Internal Control Over Financial Reporting

The management of Exelon Corporation (Exelon) is responsible for establishing and maintaining adequate internal control over financial reporting. Exelon'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 accounting principles generally accepted in the United States of America.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Exelon's management conducted an assessment of the effectiveness of Exelon's internal control over financial reporting as of December 31, 2005. In making this assessment, management used the criteria in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, Exelon's management concluded that, as of December 31, 2005, Exelon's internal control over financial reporting was effective.

Management's assessment of the effectiveness of Exelon's internal control over financial reporting as of December 31, 2005 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears on the next page of this Financial Information supplement.

February 15, 2006

Report of Independent Registered Public Accounting Firm

To the Shareholders and Board of Directors of Exelon Corporation:

We have completed integrated audits of Exelon Corporation's 2005 and 2004 consolidated financial statements and of its internal control over financial reporting as of December 31, 2005, and an audit of its 2003 consolidated financial statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Our opinions, based on our audits, are presented below.

Consolidated financial statements

In our opinion, the consolidated balance sheets and the related consolidated statements of income, comprehensive income, shareholders' equity and cash flows present fairly, in all material respects, the financial position of Exelon Corporation and its subsidiaries at December 31, 2005 and 2004, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2005 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit of financial statements includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 1 to the consolidated financial statements, Exelon Corporation changed its method of accounting for asset retirement obligations as of January 1, 2003, its method of accounting for variable interest entities in 2003 and 2004; and its method of accounting for conditional asset retirement obligations as of December 31, 2005.

Internal control over financial reporting

Also, in our opinion, management's assessment, included in Management's Report on Internal Control Over Financial Reporting appearing on the previous page of this Financial Information supplement, that the Company maintained effective internal control over financial reporting as of December 31, 2005 based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), is fairly stated, in all material respects, based on those criteria. Furthermore, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2005, based on criteria established in Internal Control—Integrated Framework issued by the 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. Our responsibility is to express opinions on management's assessment and on the effectiveness of the Company's internal control over financial reporting based on our audit. We conducted our audit of internal control over financial reporting 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. An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we consider necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

PricewaterhouseCoopers LLP
Chicago, Illinois
February 15, 2006

Exelon Corporation and Subsidiary Companies

Consolidated Statements of Income

(in millions, except per share data)	For the Years Ended December 31, 2005	2004	2003
Operating revenues	$15,357	$14,133	$15,148
Operating expenses			
Purchased power	3,162	2,709	3,459
Purchased power from AmerGen Energy Company, LLC	—	—	382
Fuel	2,484	2,220	2,353
Operating and maintenance	3,718	3,700	3,915
Impairment of goodwill	1,207	—	—
Impairment of Boston Generating, LLC long-lived assets	—	—	945
Depreciation and amortization	1,334	1,295	1,115
Taxes other than income	728	710	570
Total operating expenses	12,633	10,634	12,739
Operating income	2,724	3,499	2,409
Other income and deductions			
Interest expense	(513)	(471)	(861)
Interest expense to affiliates	(316)	(357)	(12)
Distributions on preferred securities of subsidiaries	(4)	(3)	(39)
Equity in earnings (losses) of unconsolidated affiliates	(134)	(154)	33
Other, net	138	63	(244)
Total other income and deductions	(829)	(922)	(1,123)
Income from continuing operations before income taxes and minority interest	1,895	2,577	1,286
Income taxes	944	713	389
Income from continuing operations before minority interest	951	1,864	897
Minority interest	—	6	(5)
Income from continuing operations	951	1,870	892
Discontinued operations			
Loss from discontinued operations (net of taxes of $(3), $(40) and $(49) in 2005, 2004 and 2003, respectively)	(4)	(61)	(86)
Gain (loss) on disposal of discontinued operations (net of taxes of $6, $19 and $(9) in 2005, 2004 and 2003, respectively)	18	32	(13)
Income (loss) from discontinued operations	14	(29)	(99)
Income before cumulative effect of changes in accounting principles	965	1,841	793
Cumulative effect of changes in accounting principles (net of income taxes of $(27), $17 and $69 in 2005, 2004 and 2003, respectively)	(42)	23	112
Net income	$ 923	$ 1,864	$ 905
Average shares of common stock outstanding			
Basic	669	661	651
Diluted	676	669	657
Earnings per average common share—basic:			
Income from continuing operations	$ 1.42	$ 2.83	$ 1.37
Income (loss) from discontinued operations	0.02	(0.04)	(0.15)
Income before cumulative effect of changes in accounting principles	1.44	2.79	1.22
Cumulative effect of changes in accounting principles	(0.06)	0.03	0.17
Net income	$ 1.38	$ 2.82	$ 1.39
Earnings per average common share—diluted:			
Income from continuing operations	$ 1.40	$ 2.79	$ 1.36
Income (loss) from discontinued operations	0.02	(0.04)	(0.15)
Income before cumulative effect of changes in accounting principles	1.42	2.75	1.21
Cumulative effect of changes in accounting principles	(0.06)	0.03	0.17
Net income	$ 1.36	$ 2.78	$ 1.38
Dividends per common share	$ 1.60	$ 1.26	$ 0.96

See Notes to Consolidated Financial Statements

Exelon Corporation and Subsidiary Companies
Consolidated Statements of Cash Flows

(in millions)	For the Years Ended December 31, 2005	2004	2003
Cash flows from operating activities			
Net income	$ 923	$ 1,864	$ 905
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation, amortization and accretion, including nuclear fuel	1,967	1,933	1,681
Cumulative effect of changes in accounting principles (net of income taxes)	42	(23)	(112)
Impairment of investments	—	10	309
Impairment of goodwill	1,207	—	24
Impairment of long-lived assets	—	1	966
Deferred income taxes and amortization of investment tax credits	493	202	(36)
Provision for uncollectible accounts	77	87	94
Equity in (earnings) losses of unconsolidated affiliates	134	153	(33)
(Gains) losses on sales of investments and wholly owned subsidiaries	(22)	(162)	25
Net realized (gains) losses on nuclear decommissioning trust funds	(49)	(72)	16
Other decommissioning-related activities	(15)	169	37
Other non-cash operating activities	76	(24)	18
Changes in assets and liabilities			
Accounts receivable	(279)	(123)	102
Inventories	(118)	(60)	(54)
Other current assets	(168)	46	12
Accounts payable, accrued expenses and other current liabilities	172	133	(87)
Disbursements of counterparty collateral	(244)	42	(72)
Collections of counterparty collateral	57	31	5
Income taxes	138	293	(271)
Net realized and unrealized mark-to-market and hedging transactions	(30)	49	(10)
Pension and non-pension postretirement benefits obligation	(2,003)	(270)	(144)
Other noncurrent assets and liabilities	(211)	119	9
Net cash flows provided by operating activities	2,147	4,398	3,384
Cash flows from investing activities			
Capital expenditures	(2,165)	(1,921)	(1,954)
Proceeds from liquidated damages	—	—	92
Proceeds from nuclear decommissioning trust fund sales	5,274	2,320	2,341
Investment in nuclear decommissioning trust funds	(5,501)	(2,587)	(2,564)
Acquisitions of businesses, net of cash acquired	(97)	—	(272)
Proceeds from sales of investments and wholly owned subsidiaries, net of $32 of cash sold during 2005	105	329	263
Proceeds from sales of long-lived assets	2	52	10
Investments in synthetic fuel-producing facilities	(102)	(56)	—
Change in restricted cash	21	52	(118)
Collection of other notes receivable	—	59	35
Net cash increase from consolidation of Sithe Energies, Inc.	—	19	—
Other investing activities	(24)	(6)	32
Net cash flows used in investing activities	(2,487)	(1,739)	(2,135)
Cash flows from financing activities			
Issuance of long-term debt	1,788	232	3,015
Retirement of long-term debt	(508)	(1,629)	(2,922)
Issuance of long-term debt to financing affiliates	—	—	103
Retirement of long-term debt to financing affiliates	(835)	(728)	—
Issuance of short-term debt	2,500	—	—
Retirement of short-term debt	(2,200)	—	—
Change in short-term debt	500	164	(355)
Issuance of mandatorily redeemable preferred securities	—	—	200
Retirement of mandatorily redeemable preferred securities	—	—	(250)
Payment on acquisition note payable to Sithe Energies, Inc.	—	(27)	(446)
Retirement of preferred stock	—	—	(50)
Dividends paid on common stock	(1,070)	(831)	(620)
Proceeds from employee stock plans	222	240	181
Purchase of treasury stock	(362)	(82)	—
Other financing activities	(54)	34	(96)
Net cash flows used in financing activities	(19)	(2,627)	(1,240)
Increase (decrease) in cash and cash equivalents	(359)	32	9
Cash and cash equivalents at beginning of period	499	467	469
Cash and cash equivalents, including cash held for sale	140	499	478
Cash classified as held for sale on the consolidated balance sheet	—	—	11
Cash and cash equivalents at end of period	$ 140	$ 499	$ 467

See Notes to Consolidated Financial Statements

Exelon Corporation and Subsidiary Companies

Consolidated Balance Sheets

(in millions)	December 31, 2005	December 31, 2004
Assets		
Current assets		
Cash and cash equivalents	$ 140	$ 499
Restricted cash and investments	49	60
Accounts receivable, net		
Customer	1,858	1,649
Other	337	409
Mark-to-market derivative assets	916	403
Inventories, at average cost		
Fossil fuel	311	230
Materials and supplies	351	312
Deferred income taxes	80	68
Other	595	250
Total current assets	4,637	3,880
Property, plant and equipment, net	21,981	21,482
Deferred debits and other assets		
Regulatory assets	4,386	4,790
Nuclear decommissioning trust funds	5,585	5,262
Investments	813	804
Goodwill	3,475	4,705
Mark-to-market derivative assets	311	383
Prepaid pension asset	377	—
Other	824	1,418
Total deferred debits and other assets	15,771	17,362
Total assets	$42,389	$42,724

See Notes to Consolidated Financial Statements

Exelon Corporation and Subsidiary Companies

Consolidated Balance Sheets

(in millions)	December 31, 2005	December 31, 2004
Liabilities and shareholders' equity		
Current liabilities		
Commercial paper and notes payable	$ 1,290	$ 490
Long-term debt due within one year	407	427
Long-term debt to ComEd Transitional Funding Trust and PECO Energy Transitional Trust due within one year	507	486
Accounts payable	1,467	1,255
Mark-to-market derivative liabilities	1,282	598
Accrued expenses	1,005	1,097
Other	605	483
Total current liabilities	6,563	4,836
Long-term debt	7,759	7,292
Long-term debt due to ComEd Transitional Funding Trust and PECO Energy Transitional Trust	3,456	4,311
Long-term debt to other financing trusts	545	545
Deferred credits and other liabilities		
Deferred income taxes	4,816	4,488
Unamortized investment tax credits	262	275
Asset retirement obligations	4,157	3,981
Pension obligations	268	1,993
Non-pension postretirement benefits obligations	1,014	1,065
Spent nuclear fuel obligation	906	878
Regulatory liabilities	2,170	2,204
Mark-to-market derivative liabilities	462	323
Other	798	915
Total deferred credits and other liabilities	14,853	16,122
Total liabilities	33,176	33,106
Commitments and contingencies		
Minority interest of consolidated subsidiaries	1	42
Preferred securities of subsidiaries	87	87
Shareholders' equity		
Common stock (No par value, 2,000 shares authorized, 666.4 and 664.2 shares outstanding at December 31, 2005 and 2004, respectively)	7,987	7,664
Treasury stock, at cost (9.4 and 2.5 shares held at December 31, 2005 and 2004, respectively)	(444)	(82)
Retained earnings	3,206	3,353
Accumulated other comprehensive loss	(1,624)	(1,446)
Total shareholders' equity	9,125	9,489
Total liabilities and shareholders' equity	$42,389	$42,724

See Notes to Consolidated Financial Statements

Exelon Corporation and Subsidiary Companies

Consolidated Statements of Changes in Shareholders' Equity

(Dollars in millions, shares in thousands)	Issued Shares	Common Stock	Treasury Stock	Deferred Compensation	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Shareholders' Equity
Balance, December 31, 2002	646,626	$7,092	$ —	$ (1)	$ 2,042	$(1,358)	$ 7,775
Net income	—	—	—	—	905	—	905
Long-term incentive plan activity	9,322	244	—	—	—	—	244
Employee stock purchase plan issuances	418	11	—	—	—	—	11
Amortization of deferred compensation	—	—	—	1	—	—	1
Common stock dividends declared	—	—	—	—	(625)	—	(625)
Redemption premium on PECO preferred stock	—	—	—	—	(2)	—	(2)
Other comprehensive income, net of income taxes of $217	—	—	—	—	—	249	249
Balance, December 31, 2003	656,366	7,347	—	—	2,320	(1,109)	8,558
Net income	—	—	—	—	1,864	—	1,864
Long-term incentive plan activity	10,013	307	—	—	—	—	307
Employee stock purchase plan issuances	309	10	—	—	—	—	10
Common stock purchases	—	—	(82)	—	—	—	(82)
Common stock dividends declared	—	—	—	—	(831)	—	(831)
Adjustments to accumulated other comprehensive loss due to the consolidation of Sithe	—	—	—	—	—	(6)	(6)
Other comprehensive loss, net of income taxes of $(190)	—	—	—	—	—	(331)	(331)
Balance, December 31, 2004	666,688	7,664	(82)	—	3,353	(1,446)	9,489
Net income	—	—	—	—	923	—	923
Long-term incentive plan activity	8,862	311	—	—	—	—	311
Employee stock purchase plan issuances	259	12	—	—	—	—	12
Common stock purchases	—	—	(362)	—	—	—	(362)
Common stock dividends declared	—	—	—	—	(1,070)	—	(1,070)
Other comprehensive loss, net of income taxes of $(127)	—	—	—	—	—	(178)	(178)
Balance, December 31, 2005	675,809	$7,987	$(444)	$—	$ 3,206	$(1,624)	$ 9,125

See Notes to Consolidated Financial Statements

Exelon Corporation and Subsidiary Companies

Consolidated Statements of Comprehensive Income

(in millions)	For the Years Ended December 31, 2005	2004	2003
Net income	$ 923	$1,864	$ 905
Other comprehensive income (loss)			
Minimum pension liability, net of income taxes of $3, $(228) and $16, respectively	10	(392)	26
SFAS No. 143 transition adjustment, net of income taxes of $167	—	—	168
Change in net unrealized gain (loss) on cash-flow hedges, net of income taxes of $(133), $6 and $5, respectively	(199)	8	9
Foreign currency translation adjustment, net of income taxes of $(1), $1 and $0, respectively	(3)	1	3
Unrealized gain on marketable securities, net of income taxes of $4, $31 and $29, respectively	14	52	43
Total other comprehensive income (loss)	(178)	(331)	249
Total comprehensive income	$ 745	$1,533	$1,154

See Notes to Consolidated Financial Statements

Exelon Corporation and Subsidiary Companies

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

1. Significant Accounting Policies

Description of Business

Exelon Corporation (Exelon) is a utility services holding company engaged, through its subsidiaries, in the energy delivery, generation and other businesses discussed below. The energy delivery businesses include the purchase and regulated retail and wholesale sale of electricity and distribution and transmission services by Commonwealth Edison Company (ComEd) in northern Illinois, including the City of Chicago, and by PECO Energy Company (PECO) in southeastern Pennsylvania, including the City of Philadelphia, and the purchase and regulated retail sale of natural gas and related distribution services by PECO in the Pennsylvania counties surrounding the City of Philadelphia. The generation business consists principally of the electric generating facilities and wholesale energy marketing operations of Exelon Generation Company, LLC (Generation), the competitive retail sales business of Exelon Energy Company (Exelon Energy) and certain other generation projects. Exelon Energy, which had been previously included in the Enterprises segment, became part of Generation effective January 1, 2004. Exelon sold or wound down substantially all components of Exelon Enterprises Company, LLC (Enterprises) in 2004 and 2003. As a result, as of January 1, 2005, Enterprises is no longer reported as a segment. See Note 3—Acquisitions and Dispositions for information regarding the disposition of businesses within the Enterprises segment and Note 22—Segment Information for information regarding Exelon's reportable segments.

Basis of Presentation

Exelon's consolidated financial statements include the accounts of entities in which it has a controlling financial interest, other than certain financing trusts of ComEd and PECO described below, and its proportionate interests in jointly owned electric utility plants, after the elimination of intercompany transactions. A controlling financial interest is evidenced by either a voting interest greater than 50% or a risk and rewards model that identifies Exelon or one of its subsidiaries as the primary beneficiary of the variable interest entity. Investments and joint ventures in which Exelon does not have a controlling financial interest and certain financing trusts of ComEd and PECO are accounted for under the equity or cost methods of accounting.

Exelon owns 100% of all significant consolidated subsidiaries, either directly or indirectly, except for ComEd, of which Exelon owns more than 99%, and Southeast Chicago Energy Project, LLC (SCEP), of which Exelon owns 72%. Exelon has reflected the third-party interests in the above majority-owned investments as minority interests in its consolidated financial statements.

In accordance with FASB Interpretation No. (FIN) 46 (revised December 2003), "Consolidation of Variable Interest Entities" (FIN 46-R), Sithe Energies, Inc. (Sithe) was consolidated in Exelon's financial statements as of March 31, 2004. As further discussed in Note 3—Acquisitions and Dispositions, Generation sold its investment in Sithe on January 31, 2005. Certain trusts and limited partnerships that are financing subsidiaries of ComEd and PECO have issued debt or mandatorily redeemable preferred securities. Due to the adoption of FIN 46-R, these subsidiaries are no longer consolidated as of December 31, 2003, or as of July 1, 2003 for PECO Energy Capital Trust IV (PECO Trust IV). See "Variable Interest Entities" below for further discussion of the adoption of FIN 46-R and the resulting consolidation of Sithe and the deconsolidation of these financing subsidiaries.

The share and per-share amounts included in Exelon's Notes to Consolidated Financial Statements have been adjusted for all periods presented to reflect a 2-for-1 stock split of Exelon's common stock with a distribution date of May 5, 2004. See Note 18—Common Stock for additional information regarding the stock split.

Reclassifications

Certain prior year amounts have been reclassified in the financial statements for comparative purposes. The reclassifications did not affect net income.

Use of Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States (GAAP) requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. Areas in which significant estimates have been made include, but are not limited to, the accounting for nuclear decommissioning costs and asset retirement obligations, inventory reserves, allowance for doubtful accounts, goodwill and asset impairments, pension and other postretirement benefits, derivative instruments, fixed asset depreciation, environmental costs, taxes, severance and unbilled energy revenues.

Accounting for the Effects of Regulation

Exelon accounts for its regulated operations in accordance with accounting policies prescribed by the regulatory authorities having jurisdiction, principally the Illinois Commerce Commission (ICC) and the Pennsylvania Public Utility Commission (PAPUC) under state public utility laws, the Federal Energy Regulatory Commission (FERC) under various Federal laws, and the Securities and Exchange Commission (SEC) under the Public Utility Holding Company Act of 1935 (PUHCA) prior to its repeal effective February 8, 2006, and ComEd and PECO apply SFAS No. 71, “Accounting for the Effects of Certain Types of Regulation,” (SFAS No. 71). SFAS No. 71 requires ComEd and PECO to record in its financial statements the effects of rate regulation for utility operations that meet the following criteria: (1) third-party regulation of rates; (2) cost-based rates; and (3) a reasonable assumption that all costs will be recoverable from customers through rates. Exelon believes that it is probable that its currently recorded regulatory assets and liabilities will be recovered in future rates. However, Exelon continues to evaluate ComEd’s and PECO’s abilities to apply SFAS No. 71, including, in the case of ComEd, incorporating the current events related to the regulatory and political environment in Illinois. If a separable portion of ComEd’s or PECO’s business were no longer to meet the provisions of SFAS No. 71, Exelon would be required to eliminate from its financial statements the effects of regulation for that portion, which could have a material impact on its financial condition and results of operations. See Note 4—Regulatory Issues for further information regarding the repeal of PUHCA effective February 8, 2006.

Variable Interest Entities

FIN 46 and its revision FIN 46-R addressed the requirements for consolidating certain variable interest entities. FIN 46 was effective for Exelon’s variable interest entities created after January 31, 2003. FIN 46-R was effective December 31, 2003 for Exelon’s variable interest entities that were considered to be special-purpose entities and as of March 31, 2004 for all other variable interest entities.

Exelon consolidated Sithe, 50% owned through a wholly owned subsidiary of Generation, as of March 31, 2004 pursuant to the provisions of FIN 46-R and recorded income of $32 million (net of income taxes) as a result of the reversal of guarantees of Sithe's commitments previously recorded by Generation. This income was reported as a cumulative effect of a change in accounting principle in the first quarter of 2004. As of March 31, 2004, Generation was a 50% owner of Sithe, and Exelon had accounted for Sithe as an unconsolidated equity method investment prior to March 31, 2004. Sithe owns and operates power-generating facilities and was sold by Generation on January 31, 2005. See Note 3—Acquisitions and Dispositions for additional information regarding the sale of Sithe in 2005.

PECO Trust IV, a financing subsidiary of PECO created in May 2003, was deconsolidated from the financial statements of Exelon pursuant to the provisions of FIN 46 as of July 1, 2003. Pursuant to the provisions of FIN 46-R, as of December 31, 2003, the financing trusts of ComEd, namely ComEd Financing II (formed in November 1996), ComEd Financing III (formed in September 2002), ComEd Funding LLC (formed in July 1998) and ComEd Transitional Funding Trust (formed in October 1998), and the other financing trusts of PECO, namely PECO Trust III (formed in April 1998) and PETT (formed in June 1998), were deconsolidated from Exelon's financial statements. Amounts owed to these financing trusts at December 31, 2005 and 2004 of $4.5 billion and $5.3 billion, respectively, were recorded as debt to financing trusts within Exelon's Consolidated Balance Sheets.

This change in presentation related to the financing trusts had no effect on Exelon's net income. In accordance with FIN 46-R, prior periods were not restated. The maximum exposure to loss as a result of ComEd's and PECO's involvement with the financing trusts was $46 million and $73 million, respectively, at December 31, 2005 and was $62 million and $87 million, respectively, at December 31, 2004.

Revenues

Operating Revenues. Operating revenues are recorded as service is rendered or energy is delivered to customers. At the end of each month, Exelon accrues an estimate for the unbilled amount of energy delivered or services provided to customers (see Note 5—Accounts Receivable).

Option Contracts, Swaps, and Commodity Derivatives. Premiums received and paid on option contracts and swap arrangements considered "normal" derivatives pursuant to SFAS No. 133, "Accounting for Derivatives and Hedging Activities" (SFAS No. 133) are amortized to revenue and expensed over the lives of the contracts. Certain option contracts and swap arrangements are considered derivative instruments and are recorded at fair value with subsequent changes in fair value recognized as revenues and expenses, unless hedge accounting is applied. Commodity derivatives used for trading purposes are accounted for using the mark-to-market method with unrealized gains and losses recognized in operating revenues.

Trading Activities. Exelon accounts for its trading activities under the provisions of Emerging Issues Task Force (EITF) Issue No. 02-3, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities" (EITF 02-3), which requires revenues and energy costs related to energy trading contracts to be presented on a net basis in the income statement.

Physically Settled Derivative Contracts. Exelon accounts for realized gains and losses on physically settled derivative contracts not "held for trading purposes" in accordance with EITF Issue No. 03-11, "Reporting Realized Gains and Losses on Derivative Instruments That Are Subject to FASB Statement No. 133, 'Accounting for Derivative Instruments and Hedging Activities,' and Not 'Held for

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

Trading Purposes' as Defined in EITF Issue No. 02-3, 'Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities'" (EITF 03-11).

EITF 03-11 was ratified by the FASB in August 2003. The EITF concluded that determining whether realized gains and losses on physically settled derivative contracts not "held for trading purposes" should be reported in the income statement on a gross or net basis is a matter of judgment that depends on the relevant facts and circumstances. Exelon adopted EITF 03-11 as of January 1, 2004 and presented purchased power and fuel expense net within revenues of $1,061 million and $38 million, respectively, during 2005, and $966 million and $14 million, respectively, during 2004. Prior periods were not reclassified. The adoption of EITF 03-11 had no effect on Exelon's net income. Had EITF 03-11 been retroactively applied to 2003, operating revenues, purchased power and fuel expense would have been affected as follows:

2003	As Reported	EITF 03-11 Impact	Pro Forma
Operating revenue	$15,148	$(996)	$14,152
Purchased power	3,841	(943)	2,898
Fuel expense	2,353	(53)	2,300

Income Taxes

Deferred Federal and state income taxes are provided on all significant temporary differences between the book basis and the tax basis of assets and liabilities and for tax benefits carried forward. Investment tax credits previously utilized for income tax purposes have been deferred on the Consolidated Balance Sheets and are recognized in book income over the life of the related property.

Pursuant to the Internal Revenue Code, Exelon files a consolidated Federal income tax return that includes its subsidiaries in which it owns at least 80% of the outstanding stock. Income taxes are allocated to each of Exelon's subsidiaries included in the filing of the consolidated Federal income tax return based on the separate return method. Exelon records an income tax valuation allowance for deferred tax assets which are not more likely than not to be realized in the future (see Note 12—Income Taxes).

Losses on Reacquired Debt

Recoverable losses on reacquired debt related to regulated operations are deferred and amortized to interest expense over the life of the new debt issued to finance the debt redemption consistent with rate recovery for rate-making purposes. Losses on other reacquired debt are recognized in Exelon's Consolidated Statements of Income as incurred (see Note 21—Supplemental Financial Information).

Comprehensive Income

Comprehensive income includes all changes in equity during a period except those resulting from investments by and distributions to shareholders. Other comprehensive income primarily relates to unrealized gains or losses on securities held in nuclear decommissioning trust funds, unrealized gains and losses on cash-flow hedge instruments and the minimum pension liability. Comprehensive income is reflected in the Consolidated Statements of Changes in Shareholders' Equity and the Consolidated Statements of Comprehensive Income.

Cash and Cash Equivalents

Exelon considers all temporary cash investments purchased with an original maturity of three months or less to be cash equivalents.

Restricted Cash and Investments

As of December 31, 2005, restricted cash and investments primarily represented restricted funds for payment of medical, dental, vision and long-term disability benefits. As of December 31, 2004, restricted cash related to Sithe's Independence Plant partnership distribution fund. On January 31, 2005, Generation sold its investment in Sithe.

Restricted cash and investments not available for general operations or to satisfy current liabilities are classified as noncurrent assets. As of December 31, 2005, Exelon did not have any noncurrent restricted cash and investments. As of December 31, 2004, $93 million of restricted cash and investments were classified within Exelon's deferred debits and other assets, which included $83 million of debt service reserves, major overhaul reserves of $7 million and lease service reserves of $3 million.

Allowance for Doubtful Accounts

The allowance for doubtful accounts reflects Exelon's best estimate of probable losses in the accounts receivable balances. The allowance is based on known troubled accounts, historical experience and other currently available evidence. Customer accounts are generally considered delinquent if the amount billed is not received by the time the next bill is issued, typically monthly. Customer accounts are written off based upon approved regulatory requirements.

Inventories

Inventory is recorded at the lower of cost or market, and provisions are made for excess and obsolete inventory.

Fossil Fuel. Fossil fuel inventory includes the weighted average costs of stored natural gas, propane, coal and oil. The costs of natural gas, propane, coal and oil are generally included in inventory when purchased and charged to fuel expense when used. PECO has several long-term storage contracts for natural gas as well as a liquefied natural gas storage facility.

Materials and Supplies. Materials and supplies inventory generally includes the average costs of transmission, distribution and generating plant materials. Materials are generally charged to inventory when purchased and then expensed or capitalized to plant, as appropriate, when installed.

Emission Allowances

Emission allowances are included in inventories and other deferred debits and are carried at the lower of weighted average cost or market and charged to fuel expense as they are used in operations. Exelon's emission allowance balances as of December 31, 2005 and 2004 were $112 million and $106 million, respectively.

Marketable Securities

Marketable securities are classified as available-for-sale securities and are reported at fair value pursuant to SFAS No. 115, “Accounting for Certain Investments in Debt and Equity Securities” (SFAS No. 115). Realized and unrealized gains and losses, net of tax, on nuclear decommissioning trust funds transferred to Generation from PECO and ComEd are considered in the determination of the regulatory assets and liabilities. See Note 21—Supplemental Financial Information for additional information regarding ComEd’s and PECO’s regulatory assets and liabilities. Realized and unrealized gains and losses on nuclear decommissioning trust funds for the AmerGen units are reported in other comprehensive income. At December 31, 2005 and 2004, Exelon had no held-to-maturity securities. See Note 13—Nuclear Decommissioning and Spent Fuel Storage for information regarding marketable securities held by nuclear decommissioning trust funds.

Purchased Gas Adjustment Clause

PECO’s natural gas rates are subject to a fuel adjustment clause designed to recover or refund the difference between the actual cost of purchased gas and the amount included in rates. Differences between the amounts billed to customers and the actual costs recoverable are deferred and recovered or refunded in future periods by means of prospective quarterly adjustments to rates. At December 31, 2005 and 2004, deferred energy costs of $39 million and $25 million, respectively, were recorded as current assets on Exelon’s Consolidated Balance Sheets.

Leases

Exelon accounts for leases in accordance with SFAS No. 13, “Accounting for Leases” and determines whether its long-term purchase power and sales contracts are leases pursuant to EITF Issue No. 01-8, “Determining Whether an Arrangement is a Lease” (EITF 01-8). At the inception of the lease, or subsequent modification, Exelon determines whether the lease is an operating or capital lease based upon its terms and characteristics. Several of Exelon’s long-term purchase power agreements which have been determined to be operating leases have significant contingent rental payments that are dependent on the future operating characteristics of the associated plants such as plant availability. Exelon recognizes contingent rental expense when it becomes probable of payment.

Property, Plant and Equipment

Property, plant and equipment is recorded at cost. The cost of maintenance, repairs and minor replacements of property is charged to maintenance expense as incurred.

For ComEd and PECO, upon retirement, the cost of regulated property, net of salvage, is charged to accumulated depreciation in accordance with the composite method of depreciation. For ComEd, removal costs reduce the related regulated liability. For PECO, removal costs are capitalized when incurred and depreciated over the life of the new asset constructed consistent with PECO’s regulatory recovery method. For unregulated property, the cost and accumulated depreciation of property, plant and equipment retired or otherwise disposed of are removed from the related accounts.

For Generation, upon retirement, the cost of property is charged to accumulated depreciation.

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

See Note 6—Property, Plant and Equipment and Note 21—Supplemental Financial Information for additional information regarding property, plant and equipment.

Nuclear Fuel

The cost of nuclear fuel is capitalized and charged to fuel expense using the unit-of-production method. The estimated cost of disposal of Spent Nuclear Fuel (SNF) is established per the Standard Waste Contract with the Department of Energy (DOE) and is expensed at one mill ($.001) per kilowatthour of net nuclear generation. On-site SNF storage costs are capitalized or expensed, as incurred, based upon the nature of the work performed.

Nuclear Outage Costs

Costs associated with nuclear outages are recorded in the period incurred.

Capitalized Software Costs

Costs incurred during the application development stage of software projects that are developed or obtained for internal use are capitalized. At December 31, 2005 and 2004, net unamortized capitalized software costs totaled $264 million and $311 million, respectively. Such capitalized amounts are amortized ratably over the expected lives of the projects when they become operational, generally not to exceed ten years. Certain capitalized software costs are being amortized over five to fifteen years pursuant to regulatory approval. During 2005, 2004 and 2003, Exelon amortized capitalized software costs of $76 million, $80 million and $69 million, respectively.

Depreciation and Amortization

Depreciation is provided over the estimated service lives of property, plant and equipment on a straight-line basis using the composite method. Annual depreciation provisions for financial reporting purposes, presented by average service life and as a percentage of average service life for each asset category, are presented in the tables below. See Note 6—Property, Plant and Equipment for information regarding a change in ComEd's and PECO's depreciation rates.

Average Service Life in Years by Asset Category	2005	2004	2003
Electric—transmission and distribution	5-75	5-75	8-75
Electric—generation	5-62	5-63	5-64
Gas	5-85	5-85	8-85
Common—electric and gas	5-46	5-46	6-46
Other property and equipment	5-58	5-58	5-58

Average Service Life Percentage by Asset Category	2005	2004	2003
Electric—transmission and distribution	2.79%	2.82%	2.81%
Electric—generation	3.59%	3.34%	2.90%
Gas	2.32%	2.52%	2.38%
Common—electric and gas	8.06%	4.60%	7.53%
Other property and equipment	6.97%	6.77%	8.20%

Amortization of regulatory assets is provided over the recovery period specified in the related legislation or regulatory agreement. See Note 21—Supplemental Financial Information for further information regarding the amortization of regulatory assets, nuclear fuel, asset retirement obligation and intangible assets.

Nuclear Generating Station Decommissioning

Exelon accounts for the costs of decommissioning its nuclear generating stations in accordance with SFAS No. 143. See Note 13—Nuclear Decommissioning and Spent Fuel Storage for information regarding the adoption and application of SFAS No. 143.

Capitalized Interest and Allowance for Funds Used During Construction

Exelon applies SFAS No. 34, "Capitalizing Interest Costs" to calculate the costs during construction of debt funds used to finance its non-regulated construction projects. Exelon capitalized interest of $12 million, $11 million and $15 million in 2005, 2004 and 2003, respectively.

Allowance for funds used during construction (AFUDC) is the cost, during the period of construction, of debt and equity funds used to finance construction projects for regulated operations. AFUDC is recorded as a charge to construction work in progress and as a non-cash credit to AFUDC that is included in interest expense for debt-related funds and other income and deductions for equity-related funds. The rates used for capitalizing AFUDC are computed under a method prescribed by regulatory authorities (see Note 21—Supplemental Financial Information). Exelon recorded credits to AFUDC of $10 million, $5 million and $16 million in 2005, 2004 and 2003, respectively.

Guarantees

Beginning February 1, 2003, pursuant to FIN 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness to Others (FIN 45)," Exelon recognizes, at the inception of a guarantee, a liability for the fair market value of the obligations it has undertaken in issuing the guarantee, including the ongoing obligation to perform over the term of the guarantee in the event that the specified triggering events or conditions occur.

The liability that is initially recognized at the inception of the guarantee is reduced as Exelon is released from risk under the guarantee. Depending on the nature of the guarantee, Exelon's release from risk may be recognized only upon the expiration or settlement of the guarantee or by a systematic and rational amortization method over the term of the guarantee. The recognition and subsequent adjustment of the liability are highly dependent upon the nature of the associated guarantee.

Asset Impairments

Long-Lived Assets. Exelon evaluates the carrying value of long-lived assets to be held and used for impairment whenever indications of impairment exist in accordance with the requirements of SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets" (SFAS No. 144). The carrying value of long-lived assets is considered impaired when the projected undiscounted cash flows are less than the carrying value. In that event, a loss would be recognized based on the amount by which the carrying value exceeds the fair value. Fair value is determined primarily by available market valuations or, if applicable, discounted cash flows. See Note 3—Acquisitions and Dispositions for a description of the impairment charge recorded in 2003 related to the long-lived assets of Boston Generating, LLC (Boston Generating).

Upon meeting certain criteria defined in SFAS No. 144, the assets and associated liabilities that compose a disposal group are classified as held for sale and presented separately on the Consolidated Balance Sheets. The carrying value of these assets is adjusted downward, if necessary, to the estimated sales price, less cost to sell.

Goodwill. Goodwill represents the excess of the purchase price paid over the estimated fair value of the assets acquired and liabilities assumed in the acquisition of a business. Pursuant to SFAS No. 142, “Goodwill and Other Intangible Assets” (SFAS No. 142), goodwill is not amortized but is tested for impairment at least annually or on an interim basis if an event occurs or circumstances change that would reduce the fair value of a reporting unit below its carrying value. See Note 8—Intangible Assets for information regarding the adoption of SFAS No. 142 and the results of goodwill impairment studies that have been performed, which include the $1.2 billion goodwill impairment charge recorded in 2005.

Investments. Investments are considered to be impaired when a decline in fair value is judged to be other-than-temporary. If the cost of an investment exceeds its fair value, Exelon evaluates, among other factors, general market conditions, the duration and extent to which the fair value is less than cost, as well as its intent and ability to hold the investment. Exelon also considers specific adverse conditions related to the financial health of and business outlook for the investee. Once a decline in fair value is determined to be other-than-temporary, an impairment charge is recorded and a new cost basis is established. See Note 3—Acquisitions and Dispositions for a description of the impairments recorded in 2003 related to Generation’s investment in Sithe and Note 16—Fair Value of Financial Assets and Liabilities for a description of the other-than-temporary impairments in the nuclear decommissioning trust funds determined in 2005 and 2004.

Derivative Financial Instruments

Exelon enters into derivatives to manage its exposure to fluctuations in interest rates, changes in interest rates related to planned future debt issuances and changes in the fair value of outstanding debt. Generation utilizes derivatives with respect to energy transactions to manage the utilization of its available generating capability and the supply of wholesale energy to its affiliates. Generation also utilizes energy option contracts and energy financial swap arrangements to limit the market price risk associated with forward energy commodity contracts. Additionally, Generation enters into energy-related derivatives for trading purposes. Exelon’s derivative activities are in accordance with Exelon’s Risk Management Policy (RMP).

Exelon accounts for derivative financial instruments under SFAS No. 133. Under the provisions of SFAS No. 133, all derivatives are recognized on the balance sheet at their fair value unless they qualify for a normal purchases or normal sales exception. Derivatives on the balance sheet are presented as current or noncurrent mark-to-market derivative assets or liabilities. Changes in the fair value of derivatives are recognized in earnings unless specific hedge accounting criteria are met, in which case those changes are recorded in earnings as an offset to the changes in fair value of the exposure being hedged or deferred in accumulated other comprehensive income and recognized in earnings as hedged transactions occur. Amounts recorded in earnings are included in revenue, purchased power or other, net on the consolidated statements of income.

Revenues and expenses on contracts that qualify as normal purchases or normal sales are recognized when the underlying physical transaction is completed. “Normal” purchases and sales are contracts where physical delivery is probable, quantities are expected to be used or sold in the normal course of business over a reasonable period of time, and price is not tied to an unrelated underlying derivative. As part of Generation's energy marketing business, Generation enters into contracts to buy and sell energy to meet the requirements of its customers. These contracts include short-term and long-term commitments to purchase and sell energy and energy-related products in the retail and wholesale markets with the intent and ability to deliver or take delivery. While these contracts are considered derivative financial instruments under SFAS No. 133, the majority of these transactions have been designated as "normal" purchases or "normal" sales and are thus not required to be recorded at fair value, but on an accrual basis of accounting. If it was determined that a transaction designated as a "normal" purchases or a "normal" sale no longer met the scope exceptions, the fair value of the related contract would be recorded on the balance sheet and immediately recognized through earnings.

A derivative financial instrument can be designated as a hedge of the fair value of a recognized asset or liability or of an unrecognized firm commitment (fair-value hedge), or a hedge of a forecasted transaction or the variability of cash flows to be received or paid related to a recognized asset or liability (cash-flow hedge). Changes in the fair value of a derivative that is highly effective, and is designated and qualifies as, a fair-value hedge, are recognized in earnings as offsets to the changes in fair value of the exposure being hedged. Changes in the fair value of a derivative that is highly effective, and is designated and qualifies as, a cash-flow hedge are deferred in accumulated other comprehensive income and are recognized in earnings as the hedged transactions occur. Any ineffectiveness is recognized in earnings immediately. On an ongoing basis, Exelon assesses the hedge effectiveness of all derivatives that are designated as hedges for accounting purposes in order to determine that each derivative continues to be highly effective in offsetting changes in fair values or cash flows of hedged items. If it is determined that the derivative is not highly effective as a hedge, hedge accounting will be discontinued prospectively.

Generation enters into contracts to buy and sell energy for trading purposes subject to Exelon's Risk Management Policy. These contracts are recognized on the balance sheet at fair value and changes in the fair value of these derivative financial instruments are recognized in earnings.

Severance Benefits

Exelon accounts for its ongoing severance plans in accordance with SFAS No. 112, "Employer's Accounting for Postemployment Benefits, an amendment of FASB Statements No. 5 and 43" (SFAS No. 112) and SFAS No. 88, "Employers' Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits." Amounts associated with severance benefits that are considered probable and can be reasonably estimated are accrued. See Note 9—Severance Accounting for further discussion of Exelon's accounting for severance benefits.

Retirement Benefits

Exelon's defined benefit pension plans and postretirement welfare benefit plans are accounted for in accordance with SFAS No. 87, "Employer's Accounting for Pensions" (SFAS No. 87), SFAS No. 106, "Employers' Accounting for Postretirement Benefits Other than Pensions" (SFAS No. 106) and FASB Staff Position (FSP) FAS 106-2, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003" (FSP FAS 106-2), and are disclosed in accordance with SFAS No. 132-R, "Employers' Disclosures about Pensions and Other

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

Postretirement Benefits—an Amendment of FASB Statements No. 87, 88, and 106" (revised 2003) (SFAS No. 132-R). See Note 15—Retirement Benefits for further discussion of Exelon's accounting for retirement benefits in accordance with SFAS No. 87 and SFAS No. 106 and disclosures pursuant to SFAS No. 132-R.

FSP FAS 106-2. Through its postretirement benefit plans, Exelon provides retirees with prescription drug coverage. The Medicare Prescription Drug, Improvement and Modernization Act of 2003 (Prescription Drug Act) was enacted on December 8, 2003. The Prescription Drug Act introduced a prescription drug benefit under Medicare as well as a Federal subsidy to sponsors of retiree health care benefit plans that provide a benefit that is at least actuarially equivalent to the Medicare prescription drug benefit. Management believes the prescription drug benefit provided under Exelon's postretirement benefit plans is at least actuarially equivalent to the Medicare prescription drug benefit. In response to the enactment of the Prescription Drug Act, in May 2004, the FASB issued FSP FAS 106-2, which provided transition guidance for accounting for the effects of the Prescription Drug Act and superseded FSP FAS 106-1, which had been issued in January 2004. FSP FAS 106-1 permitted a plan sponsor of a postretirement health care plan that provides a prescription drug benefit to make a one-time election to defer the accounting for the effects of the Prescription Drug Act. Exelon made the one-time election allowed by FSP FAS 106-1 during the first quarter of 2004.

During the second quarter of 2004, Exelon early adopted the provisions of FSP FAS 106-2, resulting in a remeasurement of its postretirement benefit plans' assets and accumulated postretirement benefit obligations (APBO) as of December 31, 2003. Upon adoption, the effect of the subsidy on benefits attributable to past service was accounted for as an actuarial experience gain, resulting in a decrease of the APBO of approximately $186 million. The annualized reduction in the net periodic postretirement benefit cost was approximately $40 million and $33 million in 2005 and 2004, respectively, compared to the annual cost calculated without considering the effects of the Prescription Drug Act. The effect of the subsidy on the components of net periodic postretirement benefit cost for 2005 and 2004 included in the consolidated financial statements and Note 15—Retirement Benefits was as follows:

	2005	2004
Amortization of the actuarial experience loss	$18	$15
Reduction in current period service cost	8	6
Reduction in interest cost on the APBO	14	12

Treasury Stock

Treasury shares are recorded at cost. Any shares of common stock repurchased are held as treasury shares unless cancelled or reissued.

Foreign Currency Translation

The financial statements of Exelon's foreign subsidiaries were prepared in their respective local currencies and translated into U.S. dollars based on the current exchange rates at the end of the periods for the Consolidated Balance Sheets and on weighted-average rates for the periods for the Consolidated Statements of Income. Foreign currency translation adjustments, net of deferred income tax benefits, are reflected as a component of other comprehensive income on the Consolidated Statements of Comprehensive Income and, accordingly, have no effect on net income.

New Accounting Pronouncements

EITF 03-1. In March 2004, the EITF reached a consensus on and the FASB ratified EITF Issue No. 03-1, "The Meaning of Other-Than-Temporary Impairment and Its Application to Certain Investments" (EITF 03-1). EITF 03-1 provides guidance on recognizing other-than-temporary impairments of investment securities. Exelon has adopted the disclosure requirements of EITF 03-1 for investments accounted for under FASB Statement No. 115, "Accounting for Certain Investments in Debt and Equity Securities" (SFAS No. 115). On September 30, 2004, the FASB issued FSP EITF 03-1-1, "Effective Date of Paragraphs 10-20 of EITF Issue No. 03-1, 'The Meaning of Other-Than-Temporary Impairment and its Application to Certain Investments,'" which delayed the effective date of the application guidance on impairment of securities included within EITF 03-1. The FASB, at its June 29, 2005 Board meeting, withdrew its guidance on when an impairment is other than temporary. However, EITF 03-1's provisions regarding the measurement, disclosure and post-impairment accounting guidance of debt securities, as well as the identification of impaired cost method investments remain intact. Additionally, the existing guidance under SFAS No. 115 remains in effect.

SFAS No. 151. In November 2004, the FASB issued FASB Statement No. 151, "Inventory Costs—an amendment of ARB No. 43, Chapter 4" (SFAS No. 151), which is the result of its efforts to converge U.S. accounting standards for inventories with International Accounting Standards. SFAS No. 151 requires abnormal amounts of idle facility expense, freight, handling costs and wasted material or spoilage to be recognized as current-period charges. It also requires that allocation of fixed production overheads to the costs of conversion be based on the normal capacity of the production facilities. SFAS No. 151 will be effective for inventory costs incurred beginning January 1, 2006. The adoption of this standard is not expected to have a material impact on Exelon.

SFAS No. 123-R. In December 2004, the FASB issued FASB Statement No. 123 (revised 2004), "Share-Based Payment" (SFAS No. 123-R). SFAS No. 123-R replaces SFAS No. 123, "Accounting for Stock-Based Compensation" (SFAS No. 123) and supersedes Accounting Principles Board (APB) No. 25, "Accounting for Stock Issued to Employees" (APB No. 25). SFAS No. 123-R requires that compensation cost relating to share-based payment transactions be recognized in the financial statements. That cost will be measured based on the fair value of the equity or liability instruments issued. Exelon will no longer be permitted to follow the intrinsic value accounting method of APB No. 25. APB No. 25 resulted in no expense being recorded for stock option grants for which the strike price was equal to the fair value of the underlying stock on the date of grant, which has been the situation for Exelon for all years prior to 2006. SFAS No. 123-R will be effective for Exelon in the first quarter of 2006 and will apply to all of Exelon's outstanding unvested share-based payment awards as of January 1, 2006 and all prospective awards using the modified prospective transition method without restatement of prior periods.

In March 2005, the SEC issued Staff Accounting Bulletin (SAB) No. 107 which expressed the views of the SEC regarding the interaction between SFAS No. 123-R and certain SEC rules and regulations. SAB No. 107 provides guidance related to the valuation of share-based payment arrangements for public companies, including assumptions such as expected volatility and expected term.

Exelon will determine the fair value of share-based equity or liability instruments issued to employees subsequent to January 1, 2006 using the Black-Scholes-Merton option-pricing model for stock options and a Monte Carlo simulation model for performance shares subject to market conditions to calculate the amount of compensation cost that must be recognized in the financial statements as a result of adopting SFAS No. 123-R. The dividend yield, volatility and risk-free interest rate assumptions will be estimated in a manner consistent with the methodology currently used to estimate the assumptions in 2005 disclosed in Note 18—Common Stock. Exelon estimates that the 2006 impact of adopting SFAS No. 123-R will be approximately $45 million to $65 million before income taxes and the effects of capitalization, which approximates the annual 2005, 2004 and 2003 pro forma stock-based compensation expense amounts shown in the table below. The actual cost will differ from this range due to changes in assumptions. This estimated range primarily reflects the impact of expensing stock options for the first time and accelerating the expense for new grants of stock-based awards.

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

Exelon currently accounts for its stock-based compensation plans under the intrinsic method prescribed by APB No. 25 and related interpretations and follows the disclosure requirements of SFAS No. 123 and SFAS No. 148, "Accounting for Stock-Based Compensation—Transition and Disclosure—an amendment of FASB Statement No. 123." Accordingly, compensation expense related to stock options recognized within the Consolidated Statements of Income was insignificant in 2005, 2004 and 2003. Expense recognized related to other stock-based compensation plans is further described in Note 18—Common Stock. The tables below show the effect on Exelon's net income and earnings per share had Exelon elected to account for all of its stock-based compensation plans using the fair-value method under SFAS No. 123 in 2005, 2004 and 2003:

	2005	2004	2003
Net income—as reported	$ 923	$1,864	$ 905
Add: Stock-based compensation expense included in reported net income, net of income taxes	34	39	19
Deduct: Total stock-based compensation expense determined under fair-value method for all awards, net of income taxes [(a)]	(48)	(60)	(39)
Pro forma net income	$ 909	$1,843	$ 885
Earnings per share:			
Basic—as reported	$1.38	$ 2.82	$1.39
Basic—pro forma	$1.36	$ 2.79	$1.36
Diluted—as reported	$1.36	$ 2.78	$1.38
Diluted—pro forma	$1.35	$ 2.75	$1.35

(a) The fair value of options granted was estimated using a Black-Scholes-Merton option pricing model.

Exelon recognizes the compensation cost of stock-based awards issued to retirement eligible employees that fully vest upon an employee's retirement over the nominal vesting period of performance and recognizes any remaining compensation cost at the date of retirement. Upon the adoption of SFAS No. 123-R, Exelon will be required to recognize the entire compensation cost at the grant date of new stock-based awards in which retirement-eligible employees are fully vested upon issuance (the non-substantive vesting approach). There would have not have been a material impact to Exelon's stock-based compensation expense had Exelon accounted for its stock-based awards in which retirement-eligible employees are fully vested upon issuance using the non-substantive vesting approach.

SFAS No. 153. In December 2004, the FASB issued FASB Statement No. 153, "Exchanges of Nonmonetary Assets, an amendment of APB Opinion No. 29, 'Accounting for Nonmonetary

Transactions'" (SFAS No. 153). Previously, APB Opinion No. 29 had required that the accounting for an exchange of a productive asset for a similar productive asset or an equivalent interest in the same or similar productive asset should be based on the recorded amount of the asset relinquished. The amendments made by SFAS No. 153 are based on the principle that exchanges of nonmonetary assets should be measured based on the fair value of the assets exchanged. Further, the amendments eliminate the narrow exception for nonmonetary exchanges of similar productive assets and replace it with a broader exception for exchanges of nonmonetary assets that do not have commercial substance, in essence increasing the number of exchanges that will be fair valued in the future. SFAS No. 153 was effective in the third quarter of 2005. The provisions of SFAS No. 153 are applied prospectively. The adoption of this standard did not have a material impact on Exelon's financial condition or results of operations in the third or fourth quarter of 2005.

FIN 47. In March 2005, the FASB issued FIN 47, "Accounting for Conditional Asset Retirement Obligations" (FIN 47) which clarifies that the term "conditional asset retirement obligation" as used in FASB Statement No. 143, "Accounting for Asset Retirement Obligations" (SFAS No. 143), refers to a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity. FIN 47 requires an entity to recognize a liability for the fair value of a conditional asset retirement obligation if the fair value of the liability can be reasonably estimated. FIN 47 was effective for Exelon as of December 31, 2005. See Note 14—Conditional Asset Retirement Obligations for further information.

SFAS No. 154. In May 2005, the FASB issued FASB Statement No. 154, "Accounting Changes and Error Corrections, a replacement of APB Opinion No. 20 and FASB Statement No. 3" (SFAS No. 154). Previously, APB No. 20, "Accounting Changes" and SFAS No. 3, "Reporting Accounting Changes in Interim Financial Statements" required the inclusion of the cumulative effect of changes in accounting principle in net income of the period of the change. SFAS No. 154 requires companies to recognize a change in accounting principle, including a change required by a new accounting pronouncement when the pronouncement does not include specific transition provisions, retrospectively to prior periods' financial statements. Exelon will assess the impact of a retrospective application of a change in accounting principle in accordance with SFAS No. 154 when such a change arises after the effective date of January 1, 2006.

Cumulative Effect of Changes in Accounting Principles

FIN 47. During 2005, Exelon recorded a charge of $42 million (net of income taxes of $27 million) as a cumulative effect of a change in accounting principle pursuant to the adoption of FIN 47. See discussion of the adoption of FIN 47 above.

EITF 03-16. In March 2004, the EITF reached a consensus on and the FASB ratified EITF Issue No. 03-16, "Accounting for Investments in Limited Liability Companies" (EITF 03-16). The EITF concluded that if investors in a limited liability company have specific ownership accounts, they should follow the guidance prescribed in Statement of Position 78-9, "Accounting for Investments in Real Estate Ventures," and EITF Topic No. D-46, "Accounting for Limited Partnership Investments." Otherwise, investors should follow the significant influence model prescribed in Accounting Principles Board Opinion No. 18, "The Equity Method of Accounting for Investments in Common Stock." EITF 03-16 was effective for Exelon and its subsidiaries during the third quarter of 2004. Exelon recorded a charge of $9 million (net of an income tax benefit of $5 million) as a cumulative effect of a change in accounting principle in connection with its adoption of EITF 03-16 as of July 1, 2004. This charge related to certain investments in limited liability partnerships held by Enterprises.

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

FIN 46-R. See discussion of the adoption of FIN 46-R within the "Variable Interest Entities" discussion above.

SFAS No. 143. SFAS No. 143 provides accounting guidance for retirement obligations (whether statutory, contractual or as a result of principles of promissory estoppel) associated with tangible long-lived assets. Exelon adopted SFAS No. 143 as of January 1, 2003 and recorded income of $112 million (net of income taxes) as a cumulative effect of a change in accounting principle in connection with its adoption of this standard in the first quarter of 2003. The components of the cumulative effect of a change in accounting principle, net of income taxes, were as follows:

Generation (net of income taxes of $52)	$ 80
Generation's investments in AmerGen and Sithe (net of income taxes of $18)	28
ComEd (net of income taxes of $0)	5
Enterprises (net of income taxes of $(1))	(1)
Total	$112

The following tables set forth Exelon's net income and basic and diluted earnings per common share for the years ended December 31, 2005, 2004 and 2003, adjusted as if SFAS No. 143, FIN 46-R, EITF 03-16, and FIN 47 had been applied during those periods. SFAS No. 143, FIN 46-R, EITF 03-16 and FIN 47 had adoption dates of January 1, 2003, March 31, 2004, July 1, 2004, and December 31, 2005, respectively.

	2005	2004	2003
Reported income before cumulative effect of changes in accounting principles	$965	$1,841	$ 793
Pro forma earnings effects (net of income taxes):			
FIN 47	(5)	(4)	(4)
EITF 03-16	—	(1)	—
FIN 46-R	—	—	32
Pro forma income before cumulative effect of changes in accounting principles	$960	$1,836	$ 821
Reported net income	$923	$1,864	$ 905
Pro forma earnings effects (net of income taxes):			
FIN 47	(5)	(4)	(4)
EITF 03-16	—	(1)	—
FIN 46-R	—	—	32
Reported cumulative effects of changes in accounting principles:			
FIN 47	42	—	—
EITF 03-16	—	9	—
FIN 46-R	—	(32)	—
SFAS No. 143	—	—	(112)
Pro forma net income	$960	$1,836	$ 821

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

	2005	2004	2003
Basic earnings per common share:			
Reported income before cumulative effect of changes in accounting principles	$1.44	$2.79	$1.22
Pro forma income before cumulative effect of changes in accounting principles	$1.43	$2.78	$1.26
Reported net income	$1.38	$2.82	$1.39
Pro forma net income	$1.43	$2.78	$1.26

	2005	2004	2003
Diluted earnings per common share:			
Reported income before cumulative effect of changes in accounting principles	$1.42	$2.75	$1.21
Pro forma income before cumulative effect of changes in accounting principles	$1.42	$2.74	$1.25
Reported net income	$1.36	$2.78	$1.38
Pro forma net income	$1.42	$2.74	$1.25

2. Discontinued Operations

On January 31, 2005, subsidiaries of Generation completed a series of transactions that resulted in Generation's sale of its investment in Sithe. In addition, during 2003 and 2004, Exelon sold or wound down substantially all components of Enterprises, and during 2004 Generation sold or wound down substantially all components of AllEnergy Gas & Electric Marketing LLC (AllEnergy), a business within Exelon Energy. As a result, the results of operations and any gain or loss on the sale of these entities are presented as discontinued operations in 2005 within Exelon's Consolidated Statements of Income. In addition, the results of operations of these entities have been presented as discontinued operations in 2004 and 2003 for comparative purposes. Results related to these entities were as follows:

2005	Sithe [(a)]	Enterprises [(b)]	AllEnergy	Total
Total operating revenues	$30	$18	$—	$48
Operating income (loss)	5	(8)	1	(2)
Income (loss) before income taxes and minority interest	23	(7)	1	17

(a) Sithe was sold on January 31, 2005. Accordingly, results only include one month of operations. See Note 3—Acquisitions and Dispositions for further information regarding the sale of Sithe.
(b) Excludes certain investments.

2004	Sithe [(a)]	Enterprises [(b)]	AllEnergy	Total
Total operating revenues	$227	$154	$ 8	$389
Operating loss	(7)	(57)	(2)	(66)
Loss before income taxes and minority interest	(58)	(5)	(2)	(65)

(a) Includes Sithe's results of operations from April 1, 2004 through December 31, 2004. See Note 3—Acquisitions and Dispositions for further information regarding the sale of Sithe.
(b) Excludes certain investments.

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

2003	Sithe [a]	Enterprises [b]	AllEnergy	Total
Total operating revenues	$—	$ 533	$174	$ 707
Operating loss	—	(97)	(35)	(132)
Loss before income taxes and minority interest	—	(123)	(35)	(158)

(a) Sithe's results of operations for the year 2003 were included as an unconsolidated equity method investment prior to its consolidation on March 31, 2004. See Note 3—Acquisitions and Dispositions for further information regarding the sale of Sithe.
(b) Excludes certain investments.

As discussed in Note 3—Acquisitions and Dispositions, Exelon sold the electric construction and services, underground and telecom businesses of InfraSource in 2003 and Generation sold its indirect wholly owned subsidiary Boston Generating in 2004. Because Exelon maintains significant continuing involvement with these entities, due to various contractual arrangements described in Note 3—Acquisitions and Dispositions, they have not been classified as discontinued operations within Exelon's Consolidated Statements of Income.

3. Acquisitions and Dispositions

Proposed Merger with PSEG

On December 20, 2004, Exelon entered into an Agreement and Plan of Merger (Merger Agreement) with Public Service Enterprise Group Incorporated (PSEG), an exempt public utility holding company primarily located and serving customers in New Jersey, whereby PSEG will be merged with and into Exelon (Merger). PSEG shareholders approved the Merger on July 19, 2005. Exelon shareholders approved the issuance of Exelon shares pursuant to the Merger on July 22, 2005. Under the Merger Agreement, each share of PSEG common stock will be converted into 1.225 shares of Exelon common stock. The Merger Agreement contains certain termination rights for both Exelon and PSEG, and further provides that, upon termination of the Merger Agreement under specified circumstances, (i) Exelon may be required to pay PSEG a termination fee of $400 million plus PSEG's transaction expenses up to $40 million or (ii) PSEG may be required to pay Exelon a termination fee of $400 million plus Exelon's transaction expenses up to $40 million.

In 2005, Exelon filed petitions or applications for approval or review of the Merger, or approval of matters related to the Merger, with various federal and state regulatory authorities, including the FERC under the Federal Power Act, the United States Department of Justice under the Hart Scott Rodino Antitrust Improvements Act of 1976, the PAPUC, the New Jersey Board of Public Utilities (NJBPU), the United States Nuclear Regulatory Commission (NRC), the New York Public Service Commission, the Connecticut Siting Council, the New Jersey Department of Environmental Protection (NJDEP) and the Public Utility Commission of Texas under the Texas Public Utility Regulatory Act. Various other state and Federal agencies and agencies of foreign countries have a role in reviewing various aspects of the transaction. ComEd filed a notice of the Merger with the Illinois Commerce Commission (ICC) and the ICC's general counsel confirmed that its formal approval of the Merger is not required.

As of February 14, 2006, all material regulatory approvals or reviews necessary to complete the Merger have been completed with the exception of the approval from the NJBPU and the NRC and the review by the United States Department of Justice.

The FERC approved the Merger on June 30, 2005. Exelon and PSEG proposed in their application with the FERC, and FERC approved, a market concentration mitigation plan involving the divestiture of 4,000 MW of coal, mid-merit (or intermediate) and peaking generation in the PJM region and the ongoing auction of 2,600 MW of nuclear output and the interim mitigation of fossil generation pending divestiture. Exelon and PSEG also proposed to invest a total of $25 million in transmission improvements, which was included in the proposal that was accepted by FERC. The ultimate outcome of the market concentration mitigation is dependent upon various factors, including the market conditions and buyer interest at the time the generating units and the nuclear output are offered for sale. The results of these activities, therefore, are not assured, and could have a material impact on the results of operations and cash flows of Exelon and Generation if the sales price for the divested assets is different from management's expectations. The FERC considered petitions for rehearing with respect to the order approving the Merger and affirmed its order on December 15, 2005. On January 6 and January 13, 2006, Philadelphia Gas Works/City of Philadelphia and subsidiaries of PPL Corporation, parties to the FERC proceeding, filed petitions for review of the FERC order in the United States Court of Appeals for the District of Columbia.

On January 27, 2006, the PAPUC approved the Merger and a partial settlement regarding PECO's distribution and transmission rates through 2010 and other financial commitments of PECO related to the Merger. The settlement reflected the conclusion of a process involving the majority of PECO customer groups during which PECO's cost data, return on equity and estimated Merger synergies were reviewed. The provisions of the PAPUC order and partial settlement are contingent upon the completion of the Merger. The PAPUC order and partial settlement require PECO to implement rate reductions aggregating $120 million during a four-year period and to cap its rates through the end of 2010. During the rate cap period, the PAPUC retains the right to lower PECO's rates if they are found to be excessive, and PECO retains the right to seek rate increases if certain events (such as significant increases in Federal or state income taxes or other significant changes in law or regulation that do not allow PECO to earn a fair rate of return) occur. The partial settlement also provides substantial funding for alternative energy and environmental projects, economic development, and expanded outreach and assistance for low-income customers. PECO also made commitments for enhanced customer service and reliability, commitments for charitable giving and employment, and a pledge to maintain its Philadelphia headquarters for a period of time. The total of these funding commitments is approximately $44 million, of which $30 million will be expensed at the time the Merger is completed. By separate motion, the PAPUC also indicated its intent to initiate a separate investigation, to which PECO had agreed in the partial settlement, to examine issues related to a potential combination of Philadelphia Gas Works, which provides gas distribution service in the City of Philadelphia, into Exelon's gas distribution businesses. This investigation will commence no earlier than 30 days after the close of the Merger. The outcome of this potential examination is uncertain. However, Exelon does not believe that the PAPUC has the authority to compel such a transaction if the two parties do not agree to terms through arms length negotiations.

On September 30, 2005, the administrative law judge in the proceeding before the NJBPU amended a prior prehearing order to modify the timetable for the regulatory approval process in New Jersey. The revised procedural schedule for the Merger review called for testimony to be filed from mid-November to mid-December and for hearings in January 2006. Under that revised schedule, the initial decision of the administrative law judge was expected in March 2006 and a final order from the full NJBPU was expected in May 2006. On January 25, 2006, the schedule for hearings was extended through March 27, 2006. On February 8, 2006, the administrative law judge approved a revised schedule calling for additional hearings on March 13, 14, 24 and 27, 2006. The dates originally scheduled for the administrative law judge's initial decision and the final order of the full NJBPU will also be extended but no firm dates have been set. Settlement discussions in New Jersey began in

December 2005 and are expected to resume after completion of hearings before the NJBPU. Exelon will attempt to reach a settlement that satisfactorily resolves issues and allows the Merger to close in the second quarter of 2006. However, in the absence of an earlier settlement, Exelon expects that the closing of the Merger will occur in the third quarter of 2006.

Various governmental, consumer and other parties have intervened in the proceedings before the NJBPU and other regulatory bodies. To facilitate approval of the Merger, Exelon may negotiate with these parties and may enter into settlement agreements. Orders resulting from the proceedings before the NJBPU and other regulatory bodies and settlements in connection with the proceedings could, for example, affect the extent to which Exelon and its subsidiaries may benefit from expected synergies following the Merger and could be materially different from what the Registrants expect in this and other respects, and could have a material impact on the financial condition, results of operations and cash flows of the Registrants if the Merger is completed.

The regulatory and political developments in Illinois (see Note 4—Regulatory Issues) may also have an effect on the settlement discussions and proceedings before the NJBPU could delay that regulatory approval. Some possible outcomes of the developments in Illinois could also have an effect on the timing or closing conditions to the Merger.

Exelon has capitalized certain external costs associated with the Merger since the execution of the Merger Agreement on December 20, 2004. Total capitalized costs of $46 million and $10 million are included in deferred debits and other assets on Exelon's Consolidated Balance Sheets as of December 31, 2005 and December 31, 2004, respectively.

Disposition of Enterprises Entities

Exelon Thermal Holdings, Inc. On June 30, 2004, Enterprises sold the Chicago businesses of Exelon Thermal Holdings, Inc. (Thermal) for net cash proceeds of $134 million and expected proceeds of $2 million from a working capital settlement, resulting in a pre-tax gain of $45 million. Prior to closing, Enterprises repaid $37 million of related debt, resulting in prepayment penalties of $9 million.

On September 29, 2004, Enterprises sold ETT Nevada, Inc., the holding company for its investment in Northwind Aladdin, LLC, for a net cash outflow of $1 million, resulting in a pre-tax loss of $3 million.

On October 28, 2004, Northwind Windsor, of which Enterprises owned a 50% interest, sold substantially all of its assets, providing Enterprises with cash proceeds of $8 million, resulting in a pre-tax gain of $2 million.

Exelon Services, Inc. During 2004, Enterprises disposed of or wound down all of the operating businesses of Exelon Services, Inc. (Exelon Services), including Exelon Solutions, the mechanical services businesses and the Integrated Technology Group. Total expected proceeds and the net pre-tax gain on sale recorded during 2004 related to these dispositions were $61 million and $9 million, respectively. Pre-tax impairment charges of $5 million and $14 million related to Exelon Services' tangible assets were recorded in 2004 and 2003, respectively. Exelon Services also recorded a pre-tax charge of $24 million in 2003 to impair its remaining goodwill. As of December 31, 2005 and 2004, Exelon Services had remaining assets of $51 million and $74 million, respectively, and liabilities of $5 million and $22 million, respectively, which primarily consisted of tax assets, affiliate receivables and payables, and sales proceeds to be collected.

PECO TelCove. On June 30, 2004, Enterprises sold its investment in PECO TelCove, a communications joint venture, along with certain telecommunications assets, for proceeds of $49 million. A pre-tax gain of $9 million was recorded in other income and deductions on Exelon's Consolidated Statements of Income. An impairment charge of $5 million (before income taxes) related to the telecommunications assets had been recorded in the fourth quarter of 2003.

InfraSource. On September 24, 2003, Enterprises sold the electric construction and services, underground and telecom businesses of InfraSource. Cash proceeds to Enterprises from the sale were approximately $175 million, net of transaction costs and cash transferred to the buyer upon sale, plus a $30 million subordinated note receivable maturing in 2011. At the time of closing, the present value of the note receivable was approximately $12 million. The note was collected in full during the second quarter of 2004, resulting in pre-tax income of $18 million. In connection with the transaction, Enterprises entered into an agreement that may result in certain payments to InfraSource if the amount of services Exelon purchases from InfraSource during the period from closing through 2006 is below specified thresholds. Due to Exelon's ongoing involvement with InfraSource through this agreement and in accordance with SFAS No. 144 and EITF 03-13, "Applying the Conditions in Paragraph 42 of FASB Statement No. 144 in Determining Whether to Report a Discontinued Operation," the results of InfraSource have not been classified as a discontinued operation within Exelon's Consolidated Statements of Income.

In connection with the agreement to sell InfraSource, Enterprises recorded an impairment charge during the second quarter of 2003 of approximately $48 million (before income taxes and minority interest) pursuant to SFAS No. 142 related to the goodwill recorded within the InfraSource reporting unit. Management of Enterprises primarily considered the negotiated sales price and the estimated book value of InfraSource at the time of the closing of the sale in determining the amount of the goodwill impairment charge. In connection with the closing of the sale in the third quarter of 2003, Enterprises recorded a pre-tax gain of $44 million, primarily due to the book value of InfraSource at the date of closing being lower than estimated in the second quarter of 2003. The net impact of the goodwill impairment in the second quarter and the gain recorded in the third quarter was a pre-tax loss and minority interest of $4 million for the year ended December 31, 2003. The net impact was recorded as an operating and maintenance expense within Exelon's Consolidated Statements of Income.

Sale of Investments. On December 1, 2004, Enterprises sold its limited partnership interest in EnerTech Capital Partners II, L.P. and its limited liability company interests in Kinetic Ventures I, LLC and Kinetic Ventures II, LLC for $8 million in cash and the assumption by the buyers of approximately $10 million in unfunded capital commitments. Prior to the sale, in 2004, these investments were written down to their expected sales price, resulting in pre-tax impairment charges totaling $18 million. As such, there was no net gain or loss recorded associated with the sale.

The results of Thermal and Exelon Services have been included in discontinued operations within Exelon's Consolidated Statements of Income. See Note 2—Discontinued Operations for additional information.

Investments in Synthetic Fuel-Producing Facilities

In November 2003, Exelon purchased interests in two synthetic fuel-producing facilities. The purchase price for these facilities included a combination of cash, notes payable and contingent consideration dependent upon the production level of the facilities. The notes payable recorded for the purchase of the facilities were $238 million. Exelon's right to acquire a fixed amount of tax credits generated by the facilities was recorded as an intangible asset which is amortized as the tax credits are earned.

In July 2004, Exelon purchased an interest in a limited partnership that indirectly owns four synthetic fuel-producing facilities. Exelon's purchase price for these facilities included a combination of a note payable and contingent consideration dependent upon the production levels of the facilities. The note payable recorded for the purchase of the facilities was $22 million. Exelon's right to acquire a fixed amount of tax credits generated by the facilities was recorded as an intangible asset which is amortized as these tax credits are earned.

See Note 12—Income Taxes for additional information regarding Exelon's investments in synthetic fuel-producing facilities.

Investments in Affordable Housing

On October 15, 2004 and November 12, 2004, Exelon sold investments in affordable housing for total proceeds of $78 million and recognized a net gain on sale of $4 million before income taxes.

Acquisition and Disposition of Sithe

Sithe is primarily engaged in the ownership and operation of electric wholesale generating facilities in North America. At December 31, 2004, Sithe operated nine power units with total average net capacity of 1,323 MWs. Described below is a series of transactions in 2004 and 2003 involving Generation's investment in Sithe that ultimately resulted in the sale of Generation's ownership interest in Sithe to a third party on January 31, 2005.

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 closed on the acquisition of Reservoir Capital Group's (Reservoir) 50% interest in Sithe and the sale of 100% of Sithe to Dynegy, Inc. (Dynegy). Prior to closing on the sale to Dynegy, subsidiaries of Generation received approximately $65 million in cash distributions from Sithe. As a result of the sale, Exelon deconsolidated approximately $820 million of debt from its balance sheets and was no longer required to provide $125 million of credit support to Dynegy on behalf of Sithe. Dynegy acquired $32 million of cash as part of the sale of Sithe. Additionally, Exelon recorded $55 million of liabilities related to certain indemnifications provided to Dynegy and other guarantees directly resulting from the transaction. These liabilities were taken into account in the determination of the net gain on the sale of $24 million (before income taxes). As of December 31, 2005, Exelon's accrued liabilities related with these indemnifications and guarantees were $46 million. The net decrease was a result of the unwinding of certain guarantees and tax indemnifications that were associated with the sale transaction.

Generation issued certain guarantees associated with income tax indemnifications to Dynegy in connection with the sale that were valued at approximately $8 million, of which $3 million has been unwound as of December 31, 2005. These guarantees are being accounted for under the provisions of FIN 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness to Others" (FIN 45). The exposures covered by these indemnities are anticipated to expire in 2006 and beyond. The estimated maximum possible exposure to Exelon related to the guarantees provided as part of the sales transaction to Dynegy is approximately $175 million at December 31, 2005.

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

Exelon's Consolidated Statements of Income included the following financial results related to Sithe:

	2005 [(a)]	2004 [(b)]
Operating revenues	$30	$248
Operating income	5	1
Net income (loss) [(c)]	18	(27)

(a) Sithe was sold on January 31, 2005. Accordingly, results include only one month of operations.
(b) Results include Exelon's equity-method losses from Sithe prior to its consolidation on March 31, 2004, as well as transmission congestion contract (TCC) revenues for 2004, and are not included in the discontinued operations of Sithe (see Note 2—Discontinued Operations for further information regarding the disposal of Sithe). These equity-method losses and TCC revenues are presented within income from continuing operations on the Consolidated Statements of Income.
(c) Net income for 2005 included a pre-tax gain on sale of Sithe of $24 million.

Exelon's Consolidated Balance Sheets as of December 31, 2004 included current assets, noncurrent assets, current liabilities and noncurrent liabilities, which were disposed of upon the sale of Sithe on January 31, 2005, of $57 million, $885 million, $106 million and $825 million, respectively.

Exercise of Call Option and Subsequent Agreement to Sell. On November 25, 2003, Generation, Reservoir and Sithe completed a series of transactions resulting in Generation and Reservoir each indirectly owning a 50% interest in Sithe (Generation owned 49.9% prior to November 25, 2003). See below for further details regarding these 2003 transactions.

Both Generation's and Reservoir's 50% interests in Sithe were subject to put and call options. On September 29, 2004, Generation exercised its call option and entered into an agreement to acquire Reservoir's 50% interest in Sithe for $97 million. On November 1, 2004, Generation entered into an agreement to sell Sithe to Dynegy Inc. (Dynegy) for $135 million in cash. On January 31, 2005, Generation completed the closing of the call exercise and the sale of the resulting 100% interest in Sithe. The sale did not include Sithe International, Inc., which was sold to a subsidiary of Generation in a separate transaction described below.

Acquisition of Sithe International, Inc. Sithe International, through its subsidiaries, has 49.5% interests in two Mexican business trusts that own the TEG and TEP power stations, two 230 MW petcoke-fired generating facilities in Tamuín, Mexico that commenced commercial operations in the second quarter of 2004. On October 13, 2004, Sithe transferred all of the shares of Sithe International, Inc. and its subsidiaries to a subsidiary of Generation in exchange for cancellation of a $92 million note, which is eliminated as part of the consolidation of Sithe. Effective January 26, 2005, Sithe International's name was changed to Tamuin International Inc.

2003 Transactions. On November 25, 2003, Generation, Reservoir and Sithe completed a series of transactions resulting in Generation and Reservoir each indirectly owning a 50% interest in Sithe. Immediately prior to these transactions, Sithe was owned 49.9% by Generation, 35.2% by Apollo Energy, LLC (Apollo), and 14.9% by subsidiaries of Marubeni Corporation (Marubeni).

On November 25, 2003, entities controlled by Reservoir purchased certain Sithe entities holding six U.S. generating facilities, each a qualifying facility under the Public Utility Regulatory Policies Act, in exchange for $37 million ($21 million in cash and a $16 million two-year note); and entities controlled by Marubeni purchased all of Sithe's entities and facilities outside of North America (other than Sithe Energies Australia (SEA) of which it purchased a 49.9% interest on November 24, 2003 and the remaining 50.1% interest on May 27, 2004 for separate consideration) for $178 million.

Following the sales of the above entities, Generation transferred its wholly owned subsidiary that held the Sithe investment to a newly formed holding company, EXRES SHC, Inc. The subsidiary holding the Sithe investment acquired the remaining Sithe interests from Apollo and Marubeni for $612 million using proceeds from a $580 million bridge financing and available cash. Generation sold a 50% interest in the newly formed holding company for $76 million to an entity controlled by Reservoir on November 25, 2003. On November 26, 2003, Sithe distributed $580 million of available cash to its parent, which then utilized the distributed funds to repay the bridge financing.

Guarantees. In connection with the 2003 transactions, Generation recorded obligations related to $39 million of guarantees in accordance with FIN 45. These guarantees were issued to protect Reservoir from credit exposure of certain counterparties through 2015 and other indemnities. In determining the value of the FIN 45 guarantees, Generation utilized probabilistic models to assess the possibilities of future payments under the guarantees. These guarantees were reversed upon the consolidation of Sithe in accordance with FIN 45 as this liability was associated with guarantees for the performance of a consolidated entity. The consolidation of Sithe in accordance with FIN 46-R resulted in Exelon recording income of $32 million (net of income taxes), which included the reversal of the aforementioned guarantees, as a cumulative effect of a change in accounting principle during the first quarter of 2004.

Accounting Prior to the Consolidation of Sithe on March 31, 2004. Generation had accounted for the investment in Sithe as an unconsolidated equity method investment prior to its consolidation on March 31, 2004 pursuant to FIN 46-R. See Note 1—Significant Accounting Policies for further discussion. In 2003, Exelon recorded impairment charges of $255 million (before income taxes) in other income and deductions within the Consolidated Statements of Income associated with a decline in the fair value of the Sithe investment, which was considered to be other-than-temporary. Generation's management considered various factors in the decision to impair this investment, including management's negotiations to sell its interest in Sithe. The discussions surrounding the sale indicated that the fair value of the Sithe investment was below its book value and, as such, impairment charges were required.

The book value of Generation's investment in Sithe immediately prior to its consolidation on March 31, 2004 was $49 million. For the year ended December 31, 2004, Exelon recorded $2 million of equity method losses from Sithe prior to its consolidation. For the year ended December 31, 2003 and 2002, Exelon recorded $2 million and $23 million of equity method income, respectively, related to its investment in Sithe.

Consolidation of Sithe as of March 31, 2004. As a result of the 2003 transactions referred to above, the consolidation of Sithe at March 31, 2004 was accounted for as a step acquisition pursuant to purchase accounting policies. Under the provisions of FIN 46-R, the operating results of Sithe were included in Exelon's results of operations beginning April 1, 2004.

Intangible Assets. Sithe had entered into a tolling arrangement (Tolling Agreement) with Dynegy Power Marketing and its affiliates with respect to Sithe's Independence Station. The Tolling Agreement commenced on July 1, 2001 and runs through 2014. Additionally, Sithe entered into an energy purchase agreement (Energy Purchase Agreement) with a counterparty relating to the Independence Station, which continues through 2014. As a result of the acquisition accounting described above, values were assigned to the Tolling Agreement and the Energy Purchase Agreement of approximately $73 million and $384 million, respectively, which were recorded as intangible assets on Exelon's

Consolidated Balance Sheets in deferred debits and other assets. These amounts were determined based on fair value techniques utilizing the contract terms and various other estimates including forward power prices, discount rates and option pricing models.

Prior to the sale of Sithe, the intangible assets representing the Tolling Agreement and the Energy Purchase Agreement were being amortized on a straight-line basis over the lives of the associated agreements. See Note 8—Intangible Assets for further information regarding Exelon's intangible assets.

Long-Term Debt and Letters of Credit. Substantially all of Sithe's property, plant and equipment and project agreements secured Sithe's outstanding long-term debt, which consisted primarily of project debt. During 2003, Sithe entered into an agreement with Exelon and Generation under which Exelon obtained letters of credit to support contractual obligations of Sithe and its subsidiaries. As of December 31, 2004, Exelon had obtained $111 million of letters of credit in support of Sithe's obligations. As a result of the sale of Sithe on January 31, 2005, Generation was no longer required to provide credit support, which included letters of credit.

Sale of Ownership Interest in Boston Generating, LLC

On May 25, 2004, Generation completed the sale, transfer and assignment of ownership of its indirect wholly owned subsidiary Boston Generating, which owns the companies that own Mystic 4-7, Mystic 8 and 9 and Fore River generating facilities, to a special purpose entity owned by the lenders under Boston Generating's $1.25 billion credit facility (Boston Generating Credit Facility).

The sale was pursuant to a settlement agreement reached with Boston Generating's lenders on February 23, 2004. The FERC approved the sale of Boston Generating on May 25, 2004. Responsibility for plant operations and power marketing activities were transferred to the lenders' special purpose entity on September 1, 2004.

In connection with the settlement reached on February 23, 2004, Exelon, Generation, the lenders and Raytheon Company (Raytheon), the guarantor of the obligations of the turnkey contractor under the projects' engineering, procurement and construction agreements, entered into a global settlement of all disputes relating to the construction of the Mystic 8 and 9 and Fore River generating facilities.

In connection with the decision to transition out of Boston Generating and the generating units, Exelon recorded during the third quarter of 2003 an impairment charge of long-lived assets pursuant to SFAS No. 144 of $945 million ($573 million net of income taxes) in operating expenses within its Consolidated Statements of Income.

Boston Generating was reported in the Generation segment of Exelon's consolidated financial statements prior to its sale. At the date of the sale, Boston Generating had approximately $1.2 billion in assets, primarily consisting of property, plant and equipment, and approximately $1.3 billion of liabilities of which approximately $1.0 billion was debt outstanding under the Boston Generating Credit Facility. As of the date of transfer, these amounts were eliminated from Exelon's Consolidated Balance Sheets. As a result of Boston Generating's liabilities being greater than its assets at the time of the sale, transfer and assignment of ownership, Exelon recorded a gain of $85 million ($52 million net of income taxes) in other income and deductions within the Consolidated Statements of Income in the second quarter of 2004.

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

In connection with the sale, Exelon recorded a liability associated with an existing guarantee by its subsidiary Exelon New England Holdings, LLC (Exelon New England) of fuel purchase obligations of Boston Generating. At December 31, 2005, the liability associated with this guarantee was $14 million. Due to the existence of this guarantee and in accordance with SFAS No. 144 and EITF 03-13, Generation determined that it had retained risk and continuing involvement associated with the operations of Boston Generating and, as a result, the results of Boston Generating have not been classified as a discontinued operation within Exelon's Consolidated Statements of Income. See Note 20—Commitments and Contingencies for further information regarding the guarantee.

Exelon's Consolidated Statements of Income include the following results related to Boston Generating:

	2004	2003
Operating revenues	$248	$ 618
Operating loss [(a)]	(49)	(954)
Income (loss) [(b)]	21	(583)

(a) The operating loss in 2003 included an impairment loss of $945 million ($573 million net of income taxes) related to Boston Generating's long-lived assets.

(b) Net income for 2004 included an after-tax gain of $52 million related to the sale of Boston Generating in the second quarter of 2004.

Acquisition of AmerGen Energy Company, LLC

On December 22, 2003, Generation purchased British Energy plc's (British Energy) 50% interest in AmerGen Energy Company, LLC (AmerGen). The resolution of purchase price contingencies related to the valuation of long-lived assets was finalized during the fourth quarter of 2004, reflecting the final purchase price of $267 million after working capital adjustments.

Prior to the purchase, Generation was a 50% owner of AmerGen and had accounted for the investment as an unconsolidated equity method investment. From January 1, 2003 through the date of closing, Generation recorded $47 million ($28 million, net of tax) of equity in earnings of unconsolidated affiliates related to its investment in AmerGen and recorded $382 million of purchased power from AmerGen. The book value of Generation's investment in AmerGen prior to the purchase was $316 million.

In connection with the purchase of Unit No. 1 of the Three Mile Island (TMI) facility by AmerGen in 2000, AmerGen entered into an agreement with the seller whereby the seller would receive additional consideration based upon future purchase power prices through 2009. Under the terms of the agreement, approximately $11 million and $7 million had been accrued at December 31, 2005 and 2004, respectively. The amount accrued as of December 31, 2005 will be payable to the former owners of the TMI facility in the first quarter of 2006 and the amount accrued as of December 31, 2004 was paid in the first quarter of 2005. These payments represented contingent consideration for the original acquisition and have accordingly been reflected as an increase to the long-lived assets associated with the TMI facility, and are being depreciated over the remaining useful life of the facility.

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

Selected Pro Forma and Consolidating Financial Information (Unaudited)

The following unaudited pro forma financial information gives effect to the acquisition on December 22, 2003 of the remaining 50% interest in AmerGen by Generation and the sale of Boston Generating by Generation on May 25, 2004, in each case, as if the transaction had occurred on January 1, 2003.

2004	Exelon As Reported	Sale of Boston Generating	Eliminating Entries	Pro Forma Exelon
Total operating revenues	$14,133	$ 248	$ —	$13,885
Operating income (loss)	3,499	(49)	—	3,548
Income from continuing operations	1,870	21	—	1,849

2003	Exelon As Reported	Acquisition of 50% of AmerGen	Sale of Boston Generating	Eliminating Entries [(a)]	Pro Forma Exelon
Total operating revenues	$15,148	$ 623	$ 618	$(382)	$14,771
Operating income (loss)	2,409	99	(954)	—	3,462
Income (loss) from continuing operations	892	89	(583)	(47)	1,517

(a) Represents the elimination of intercompany revenues at AmerGen and equity in earnings from AmerGen in 2003.

The above unaudited pro-forma financial information should not be relied upon as being indicative of the historical results that would have been obtained if the transactions had actually occurred in prior periods nor of the results that might be obtained in the future.

Condensed Consolidating Balance Sheet at December 31, 2004 (Unaudited)

The following condensed consolidating financial information presents the financial position of Exelon and Sithe, as well as eliminating entries, related primarily to acquisition notes payable and receivables between Generation and Sithe.

December 31, 2004	Pro Forma Exelon	Sithe	Eliminating Entries	Exelon As Reported
Assets				
Current assets	$ 3,905	$ 336	$(361)	$ 3,880
Property, plant and equipment, net	21,212	270	—	21,482
Other noncurrent assets	16,643	750	(31)	17,362
Total assets	$41,760	$1,356	$(392)	$42,724
Liabilities and shareholders' equity				
Current liabilities	$ 4,874	$ 323	$(361)	$ 4,836
Long-term debt	11,363	785	—	12,148
Other long-term liabilities [(a)]	15,947	181	36	16,164
Shareholders' equity [(b)]	9,576	67	(67)	9,576
Total liabilities and shareholders' equity	$41,760	$1,356	$(392)	$42,724

(a) Includes minority interest in consolidated subsidiaries.
(b) Includes preferred securities of subsidiaries.

4. Regulatory Issues

ComEd

Illinois Procurement Filing. In 2004, the ICC initiated and conducted a workshop process to consider issues related to retail electric service in the post-transition period (i.e., post 2006). Issues addressed included utility wholesale generation supply procurement methodology, rates, competition and utility service obligations and energy assistance programs. All interested parties were invited to participate. The end result was a report from the ICC to the Illinois General Assembly that was generally supportive of utilities competitively procuring generation supply through a reverse-auction process with full recovery of the supply costs from retail customers while being mindful of consumer protections. In the proposed reverse-auction model, qualified energy suppliers would compete in a transparent, fair and structured auction to provide energy to the utilities and their customers; winning bidders would provide the power needed at the price determined by the auction's results; and the utilities would make no profit on the energy but would recover from customers the cost of procurement. The ICC staff would oversee the entire process.

On February 25, 2005, ComEd filed with the ICC seeking regulatory approval of tariffs that implement the methodologies supported by the report, including a proposal consistent with the reverse-auction process described above (the Procurement Case). As requested by ComEd, the ICC initiated hearings on the matter. The Illinois Attorney General, Citizens' Utility Board (CUB), Cook County State's Attorney's Office and the Environmental Law and Public Policy Center subsequently filed a motion to dismiss the proceeding arguing that customers whose retail service has not been declared competitive are entitled to cost-based rates for power and its delivery and that the ICC lacked authority to approve rates based on the market value of power, as proposed by ComEd. On June 1, 2005 the administrative law judge denied the motion and, on July 13, 2005, the ICC denied the appeal. On December 5, 2005, the administrative law judge issued a proposed order that recommended that the ICC approve the competitive procurement process similar to the ComEd proposal. The administrative law judge reaffirmed an earlier ruling that the ICC has legal authority under the Public Utility Act to approve an auction process and the resulting rates. The proposed order also increased the regulatory oversight of the process.

On January 24, 2006, the ICC, by a unanimous vote, approved a reverse-auction competitive bidding process for procurement of power by ComEd for the time period after 2006. The procurement process is similar to the process described in the Procurement Case and the administrative law judge's order described above, with some modifications to enhance consumer protection. The auction will be administered by an independent auction manager, with oversight by the ICC staff. The first auction is scheduled to take place during the fall of 2006, at which time ComEd's entire load will be up for bid. To mitigate the effects of changes in future prices, the load will be staggered in three-year contracts. To further mitigate the impact on its residential customers of transitioning to this process, ComEd has offered to develop a "cap and deferral" proposal to ease the impact of the expected increase in rates on residential customers, some or all of which could require regulatory or legislative approval to implement. A cap and deferral proposal, generally speaking, would limit the procurement costs that ComEd could pass through to its customers for a specified period of time and allow ComEd to collect any unrecovered procurement costs in later years.

Several parties that were opposed to the Procurement Case have indicated that they will petition the ICC for rehearing and will challenge the ICC decision in court. ComEd also petitioned for rehearing of the ICC decision on certain issues, but that petition was denied by the ICC on February 8, 2006. It is also possible that interested parties could introduce legislation in Illinois in an attempt to modify the procurement process or the rates that ComEd may charge consumers for the power ComEd purchases to meet the needs of consumers. The Illinois General Assembly has held hearings concerning generation procurement after 2006, and it may take action on this issue.

On September 1, 2005, the Illinois Attorney General, the Cook County State's Attorney, CUB and the Environmental Law and Public Policy Center filed a two-count complaint in the Chancery Division of the Circuit Court of Cook County against the ICC and the individual ICC commissioners (the Procurement Litigation). The Procurement Litigation sought to block the ICC from approving the Procurement Case on the theory that the ICC lacked the authority to approve the rates because not all of the services that will be provided under the Procurement Case have been declared competitive and do not qualify for market-based rates. The legal argument underlying the Procurement Litigation is substantially similar to the legal argument that was presented to the administrative law judge, and to the ICC on appeal, and rejected by both, in the third quarter of 2005. ComEd intervened in the Procurement Litigation to deny the allegations in the complaint and sought a determination that the ICC has appropriate legal authority to approve the proposed electricity procurement process pending before the ICC in the Procurement Case. ComEd moved for summary judgment in the litigation, and the ICC moved to dismiss one claim in the litigation and for summary judgment on the other claim. A hearing on the motions was held on December 14, 2005 and the court issued a written order on January 20, 2006 denying the relief sought by the plaintiffs and dismissing the case with prejudice.

On October 17, 2005, ComEd and Generation filed an application with the FERC seeking approval that the proposed Illinois auction process meets FERC principles and that if Generation is selected as a winning bidder in the Illinois auction, the standard agreements under which Generation would sell energy, capacity and ancillary services to ComEd would be acceptable to the FERC. On December 16, 2005, the FERC issued an order granting both requests.

In November 2005, ComEd announced several actions intended to affirm the fact that ComEd is an independent entity, separate and distinct from its parent Exelon, and to strengthen ComEd's ability to successfully manage some potentially challenging financial and strategic issues as Illinois continues its transition to restructuring after 2006. The actions include the election of a new board of directors of ComEd and selection of senior officers. The senior officers have responsibilities solely for ComEd.

The ICC, in its Order approving the Procurement Case, also ordered its Staff to "present orders initiating three separate rulemakings regarding demand response programs, energy efficiency programs and renewable energy resources to the Commission within thirty (30) days of the entry of this Order." ComEd intends to participate in any such rulemakings.

Illinois Rate Case. On August 31, 2005, ComEd filed a rate case with the ICC, which seeks, among other things, to allocate the costs of delivering electricity and to adjust ComEd's rates for delivering electricity effective January 2, 2007 (Rate Case). Several intervenors in the Rate Case, including the ICC staff and the Illinois Attorney General, have suggested, and provided testimony, that ComEd's rates should actually be reduced. The commodity component of ComEd's rates will be established by the reverse-auction process in accordance with the ICC order in the Procurement Case, assuming the ICC order on this matter is upheld upon appeal. The results of the Rate Case are not expected to be known until at least the third quarter of 2006.

Post 2006. ComEd cannot predict the results of the Rate Case before the ICC or whether the Illinois General Assembly might take action that could have a material impact on the outcome of the regulatory process. However, if the price at which ComEd is allowed to sell energy beginning in 2007 is below ComEd's cost to procure and deliver electricity, there may be material adverse consequences to Exelon. Exelon believes that these potential material adverse consequences could include, but may not be limited to, loss of ComEd's investment grade credit rating and a possible reduction in other credit ratings, limited or lost access for ComEd to credit markets to finance operations and capital investment, and loss of ComEd's capacity to enter into bilateral long-term energy procurement contracts, which would likely force ComEd to procure electricity at more volatile and potentially higher prices in the spot market. Moreover, to the extent ComEd is not permitted to recover its costs, ComEd's ability to maintain and improve service may be diminished and its ability to maintain reliability may be impaired. In the nearer term, these prospects could have adverse effects on ComEd's liquidity if vendors reduce credit or shorten payment terms or if ComEd's financing alternatives become more limited and significantly less flexible. ComEd also cannot predict the long-term impact of customer choice for energy supply on its results of operations.

PJM Integration. On June 2, 2003, ComEd began receiving electric transmission reservation services from PJM Interconnection, LLC (PJM) and transferred control of ComEd's Open Access Same Time Information System to PJM. On April 27, 2004, the FERC issued its order approving ComEd's application to complete its integration into PJM, subject to certain stipulations. ComEd agreed to these stipulations and fully integrated its transmission facilities into PJM on May 1, 2004.

Delivery Service Rates. On March 3, 2003, ComEd entered into, and the ICC subsequently entered orders to implement, an agreement (Agreement) with various Illinois retail market participants and other interested parties that settled, among other things, delivery service rates and the market value index proceeding and facilitates competitive service declarations for large-load customers and an extension of ComEd's purchase power agreement (PPA) with Generation. The effect of the Agreement is to lower competitive transition charge (CTC) collections that ComEd receives from customers who take electricity from an alternative electric supplier or under the purchase power option (PPO) through 2006. The Agreement also allows customers to lock in current CTCs for multiple years. In 2005, 2004 and 2003, ComEd collected $105 million, $169 million and $304 million in CTC revenues, respectively.

In 2003, ComEd recorded a charge to earnings associated with the required funding of specified programs and initiatives associated with the Agreement of $51 million (before income taxes) on a present value basis. This amount was partially offset by the reversal of a $12 million (before income taxes) reserve established in the third quarter of 2002 for a potential capital disallowance in ComEd's delivery services rate proceeding and a credit of $10 million (before income taxes) related to the capitalization of employee incentive payments provided for in the delivery services order. The charge of $51 million and the credit of $10 million were recorded in operating and maintenance expense and the reversal of the $12 million reserve was recorded in other, net within Exelon's Consolidated Statements of Income. The net charge for these items was $29 million (before income taxes). In accordance with the Agreement, ComEd made payments of $10 million, $10 million and $23 million during 2005, 2004 and 2003, respectively.

Competitive Service Declarations. On November 14, 2002, the ICC allowed ComEd, by operation of law, to revise its provider of last resort obligation to be the back-up energy supplier at market-based rates for certain customers with energy demands of at least three MWs. About 370 of ComEd's largest energy customers are affected, representing an aggregate supply obligation or load of approximately 2,500 MWs. These customers will not have a right to take bundled service after June 2006 or to return to bundled rates if they choose an alternative supplier prior to June 2006.

On March 28, 2003, the ICC approved changes to ComEd's real-time pricing tariff for non-residential customers, including those with energy demands of at least three MWs, who choose hourly energy supply for their electric power and energy. The ICC orders were affirmed on appeal.

Rate Reductions and Return on Common Equity Threshold. The Illinois restructuring legislation, as amended, required a 15% residential base rate reduction effective August 1, 1998 and an additional 5% residential base rate reduction effective October 1, 2001. In addition, a base rate freeze, reflecting the residential base rate reduction, is in effect through January 1, 2007. A utility may request a rate increase during the rate freeze period only when necessary to ensure the utility's financial viability. Under the Illinois legislation, if the two-year average of the earned return on common equity of a utility through December 31, 2006 exceeds an established threshold, one-half of the excess earnings must be refunded to customers. The threshold rate of return on common equity is based on a two-year average of the Monthly Treasury Bond Long-Term Average Rates (20 years and above) plus 8.5% in the years 2000 through 2006. Earnings for purposes of ComEd's threshold include ComEd's net income calculated in accordance with GAAP and reflect the amortization of regulatory assets. Under Illinois statute, any impairment of goodwill would have no impact on the determination of the cap on ComEd's allowed equity return during the transition period. As a result of the Illinois legislation, at December 31, 2005, ComEd had a regulatory asset related to recoverable transition costs with an unamortized balance of $43 million that it expects to fully recover and amortize by the end of 2006. Consistent with the provisions of the Illinois legislation, regulatory assets may be recovered in amounts that provide ComEd an earned return on common equity within the Illinois legislation earnings threshold. ComEd has not triggered the earnings sharing provision through 2005.

Open Access Transmission Tariff. On November 10, 2003, the FERC issued an order allowing ComEd to put into effect, subject to refund and rehearing, new transmission rates designed to reflect nearly $500 million of infrastructure investments made since 1998; however, because of the Illinois retail rate freeze and the method for calculating CTCs, the increase is not expected to significantly increase operating revenues until January 2, 2007. During the third quarter of 2004, a settlement agreement was reached which was approved by the FERC during the fourth quarter of 2004, which established new rates that became effective May 1, 2004.

PECO

Partial Settlement before the PAPUC. On January 27, 2006, the PAPUC approved the Merger and a partial settlement regarding PECO's distribution and transmission rates through 2010 and other financial commitments of PECO related to the Merger. The settlement reflected the conclusion of a process involving the majority of PECO customer groups during which PECO's cost data, return on equity and estimated Merger synergies were reviewed. The provisions of the PAPUC order and partial settlement are contingent upon the completion of the Merger. The PAPUC order and partial settlement require PECO to implement rate reductions aggregating $120 million during a four-year period and to cap its rates through the end of 2010. During the rate cap period, the PAPUC retains the right to lower PECO's rates if they are found to be excessive, and PECO retains the right to seek rate increases if certain events (such as significant increases in Federal or state income taxes or other significant changes in law or regulation that do not allow PECO to earn a fair rate of return) occur. The partial settlement also provides substantial funding for alternative energy and environmental projects, economic development, and expanded outreach and assistance for low-income customers. PECO also made commitments for enhanced customer service and reliability, commitments for charitable giving and employment, and a pledge to maintain its Philadelphia headquarters for a period of time. The total of these funding commitments is approximately $44 million, of which $30 million will be expensed at the time the Merger is completed. By separate motion, the PAPUC also indicated its intent to initiate a separate investigation, to which PECO had agreed in the partial settlement, to examine issues related to a potential combination of Philadelphia Gas Works, which provides gas distribution service in the City of Philadelphia, into Exelon's gas distribution businesses. This investigation will commence no earlier than 30 days after the close of the Merger. The outcome of this potential examination is uncertain. However, Exelon does not believe that the PAPUC has the authority to compel such a transaction if the two parties do not agree to terms through arms length negotiations.

Rate limitations. Pursuant to a settlement agreement related to the merger of Exelon, Unicom Corporation and PECO on October 20, 2000 (PECO / Unicom Merger) with the PAPUC, PECO was subject to agreed-upon electric service rate reductions of $200 million, in aggregate, for the period January 1, 2002 through December 31, 2005. As required by the 1998 electric restructuring settlement and as modified by the PECO / Unicom Merger-related settlement agreement, PECO is subject to rate caps (subject to limited exceptions for significant increases in Federal or state income taxes or other significant changes in law or regulation that do not allow PECO to earn a fair rate of return) on its transmission and distribution rates through December 31, 2006, and on its energy rates through December 31, 2010.

ComEd and PECO

Through and Out Rates / SECA. In November 2004, the FERC issued two orders authorizing ComEd and PECO to recover amounts for a limited time during a specified transitional period as a result of the elimination of through and out (T&O) rates for transmission service scheduled out of, or across, their respective transmission systems and ending within pre-expansion PJM Interconnection, LLC (PJM) or Midwest Independent System Operators (MISO) territories. T&O rates were terminated pursuant to FERC orders, effective December 1, 2004. The new rates, known as Seams Elimination Charge/Cost Adjustment/Assignment (SECA), are collected from load-serving entities within PJM and MISO over a transitional period from December 1, 2004 through March 31, 2006, subject to refund, surcharge and hearing. As load-serving entities, ComEd and PECO are also required to pay SECA rates during the transitional period based on the benefits they receive from the elimination of T&O rates of other transmission owners within PJM and MISO.

During 2004, prior to the termination of T&O rates, ComEd and PECO had net T&O collections of approximately $50 million and $3 million, respectively. As a result of the November 2004 FERC orders and potential appeals, ComEd may see reduced net collections, and PECO may become a net payer of SECA charges. Since the inception of the SECA rates in December 2004, ComEd has recorded approximately $44 million of SECA collections net of SECA charges, including $40 million in 2005, while PECO has recorded $7 million of SECA charges net of SECA collections, including $6 million in 2005. Management of each of ComEd and PECO believes that appropriate reserves have been established in the event that such SECA collections are required to be refunded. However, as the above amounts collected under the SECA rates are subject to refund and surcharge and the ultimate outcome of the proceeding establishing SECA rates is uncertain, the result of this proceeding may have an effect on ComEd's and PECO's financial condition, results of operations and cash flows.

Customer Choice. All ComEd's retail customers are eligible to choose an alternative electric supplier and most non-residential customers may also buy electricity from ComEd at market-based prices under the PPO. One alternative supplier was approved to serve residential customers in the

ComEd service territory. However, as of December 31, 2005, no residential customers have selected this alternative supplier. As of December 31, 2005, approximately 21,300 non-residential customers, or 33% of ComEd's annual retail kilowatthour sales, had elected either the PPO or an alternative electric supplier. Customers who receive energy from an alternative supplier continue to pay a delivery charge.

All PECO customers may choose to purchase energy from an alternative electric supplier. As of December 31, 2005, approximately 44,500 customers, representing approximately 5% of PECO's annual kilowatthour sales, had elected to purchase their electric energy from an alternative electric supplier. Customers who receive energy from an alternative electric supplier continue to pay delivery charges and CTCs.

Nuclear Decommissioning Costs. In connection with the transfer of ComEd's nuclear generating stations to Generation, the ICC permitted ComEd to recover $73 million per year from retail customers for decommissioning for the years 2001 through 2004 and, depending upon the portion of the output from those stations taken by ComEd, up to $73 million annually in 2005 and 2006. Because ComEd did not take all of the output of these stations, actual collections were $68 million in 2005 and are expected to be a similar amount in 2006. Subsequent to 2006, there will be no further recoveries of decommissioning costs from ComEd's customers. Any surplus funds after a nuclear station is decommissioned must be refunded to ComEd's customers. The amounts collected by ComEd from retail customers are remitted to Generation. Effective January 1, 2004, the PAPUC approved an adjustment to PECO's nuclear decommissioning cost adjustment clause permitting PECO to recover an additional $3.6 million annually, or $33 million compared to $29 million previously. The amounts collected by PECO from retail customers are remitted to Generation.

See Note 13—Nuclear Decommissioning and Spent Fuel Storage.

Generation

Market-Based Rates Filing. On July 5, 2005, the FERC approved Generation's continued authority to charge market-based rates for wholesale sales of electricity, including to its affiliates ComEd and PECO. In the same order, the FERC stated that Generation had failed to address the affiliate abuse prong of the FERC's market-based rate eligibility test and used that statement as the basis for instituting a proceeding under the provision of the Federal Power Act, section 206 and establishing a refund effective date of July 26, 2005 in the event that the FERC ultimately found that Generation did not, in fact, qualify for market-based rates. The FERC ordered Generation to make a compliance filing within 30 days of the order addressing the affiliate abuse and reciprocal dealing prong of the market-based rate test.

On August 4, 2005, Generation filed a Petition for Rehearing asking the FERC to rescind the part of its market-based rate order that had opened a section 206 investigation into the issue of affiliate abuse and established a refund effective date. Generation had addressed the affiliate abuse issue in its original November 2003 triennial update filing. The September 2004 filing had addressed only the new generation market power issue, as the FERC had directed. In the August 2005 filing, Generation noted the original reference in the September 2004 filing to the fact that FERC had previously found that circumstances existed that guarded against affiliate abuse. Generation further noted that as of both the September 2004 and August 2005 filings there had been no change in the circumstances cited in FERC's original order granting authority to Generation to sell electricity at market-based rates. Generation's pleading asks the FERC to either grant the rehearing request or consider the August 2005 filing to be the required compliance filing.

The July 2005 market-based rate order also directed Exelon to make compliance filings within 30 days of the order amending the market-based rate tariffs of Exelon's various subsidiaries to include prohibiting sales of electricity to Public Service and Gas Company (PSE&G), PSEG's regulated utility, unless specific authority were sought for such sales under Section 203 of the Federal Power Act. These compliance filings were made in accordance with the order.

Exelon expects the FERC to make a decision in 2006. If the FERC were to suspend Generation's market-based rate authority, Generation would be required to supply and implement a plan for mitigation of market power. FERC's default mitigation would require Generation to file and obtain FERC acceptance of cost-based rate schedules or schedules tied to a public index. In addition, the loss of market-based rate authority would subject Generation to the accounting, record-keeping and reporting requirements that are imposed on public utilities with cost-based rate schedules.

Service Life Extension. Upon the December 2003 acquisition of the remaining 50% interest in AmerGen, Generation changed its accounting estimates related to the depreciation of certain AmerGen generating facilities to conform with Generation's depreciation policies. The estimated service lives were extended by 20 years for the three AmerGen stations. These changes were based on engineering and economic feasibility analyses performed by Generation. The service life extensions are subject to approval by the Nuclear Regulatory Commission (NRC) of renewals of the existing NRC operating licenses. In the first quarter of 2005, Generation applied the same depreciation estimated useful life assumption to its ownership share in the Salem Generating Station.

License Renewals. In December 2004, the NRC issued an order that will permit the Oyster Creek Generating Station (Oyster Creek) to operate beyond its license expiration in April 2009 if the NRC has not completed reviewing the application for renewal. In July 2005, Generation applied for license renewal for Oyster Creek, and is planning on filing for license renewals for TMI Unit 1 and the Clinton Nuclear Power Station (Clinton) on a timeline consistent and integrated with the other planned license renewal filings for the Generation nuclear fleet. On October 28, 2004, the NRC approved 20-year renewals of the operating licenses for Generation's Dresden and Quad Cities generating stations. The licenses for Dresden Unit 2, Dresden Unit 3 and Quad Cities Units 1 and 2 were renewed to 2029, 2031 and 2032, respectively. On May 7, 2003, the operating licenses for Peach Bottom Unit 2 and Peach Bottom Unit 3 were renewed to 2033 and 2034, respectively. Depreciation provisions are based on the estimated useful lives of the stations, which assumes the renewal of the licenses for all nuclear generating stations. As a result, these license renewals had no impact on the Consolidated Statements of Income.

Exelon, ComEd, PECO and Generation

The Energy Policy Act of 2005. The Energy Policy Act of 2005 (the Energy Policy Act), which was signed into law on August 8, 2005, implements several significant changes intended to improve electric reliability, promote investment in electric facilities, streamline electric regulation, improve wholesale competition, address problems identified in the Western energy crisis and Enron collapse, promote fuel diversity and cleaner fuel sources, and promote greater efficiency in electric generation, delivery and use.

The Energy Policy Act also transfers to FERC certain additional authority. FERC obtains new authority to review the acquisition or merger of generating facilities, along with the responsibility to address more explicitly cross-subsidization issues in these situations. FERC now has the authority to approve siting of electric transmission facilities located in national interest electric transmission corridors if states cannot or will not act in a timely manner to approve siting. The Energy Policy Act also creates a self-regulating electric reliability organization with FERC oversight to enforce reliability rules.

In addition, the Energy Policy Act extends the Price-Anderson Act to December 31, 2025. See Note 20—Commitments and Contingencies for further discussion of the Price-Anderson Act.

Additionally, the Energy Policy Act repealed PUHCA effective February 8, 2006. Since Exelon was a registered holding company under PUHCA, Exelon and its subsidiaries were subject to a number of restrictions. These restrictions involved financings, investments and affiliate transactions. Exelon had an order under PUHCA authorizing financing transactions within certain limits. Exelon also had an order under PUHCA authorizing development activities, the formation of new intermediate subsidiaries for internal corporate structuring, internal corporate reorganizations, and investments in certain non-U.S. energy-related subsidiaries. PUHCA also limited the businesses in which Exelon could engage in and the investments that Exelon could make, and required that Exelon's utility subsidiaries constituted a single system that could be operated in an efficient, coordinated manner. With the repeal of PUHCA, Exelon is no longer subject to those restrictions. However, Section 203 of the Federal Power Act, as amended by the Energy Policy Act and regulations thereunder, governs intercompany system financings and cash management arrangements, certain corporate internal reorganizations, and certain holding company acquisitions of public utility and holding company securities. FERC obtained additional jurisdiction for the review of affiliate transactions, and FERC's financing jurisdiction resumes to the extent that it was preempted by PUHCA. With the repeal of PUHCA, the SEC's financing jurisdiction under PUHCA for ComEd's and PECO's short-term financings and Generation's financings reverted to FERC. Exelon's financings are not subject to FERC jurisdiction.

On December 7, 2005, ComEd and PECO filed applications for short-term financing authority with the FERC in the amounts of $2.5 billion and $1.5 billion, respectively. In February 2006, ComEd and PECO received orders from the FERC approving their requests, effective February 8, 2006 through December 31, 2007.

Generation currently has blanket financing authority that it received from FERC in November 2000 that became effective again with the repeal of PUHCA. If the FERC proceeding relating to Generation's market-based rate authority results in revocation of that authority, Generation's blanket financing authority may also be revoked. If that financing authority is revoked, it is possible that the revocation of financing authority would be effective prospectively. It is also possible that the revocation of financing authority might be retroactive to October 2, 2005. FERC has adopted regulations that would grandfather prior SEC approvals of financings at a company's election. The FERC regulations require that companies intending to issue securities in reliance on their SEC financing orders file with FERC a copy of their SEC financing order within 30 days after the effective date of PUHCA repeal. In light of the potential uncertainty relating to the possible revocation of FERC's blanket financing authority, Exelon has filed its SEC financing order with the FERC. The SEC financing order contains certain terms, limits, and reporting requirements which Exelon continues to review to determine the extent to which it would be subject to such conditions.

To the extent that the SEC's jurisdiction under PUHCA preempted certain aspects of state regulation of Exelon, the repeal of PUHCA will permit the states in which Exelon and its subsidiaries operate to adopt additional regulations if they so choose, absent any preemption by the FERC.

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

5. Accounts Receivable

Customer accounts receivable at December 31, 2005 and 2004 included estimated unbilled revenues associated with unread meters, representing an estimate for the unbilled amount of energy or services provided to customers, and allowance for uncollectible accounts as follows:

	2005	2004
Unbilled revenues	$986	$867
Allowance for uncollectible accounts	77	93

PECO is party to an agreement with a financial institution under which it can sell or finance with limited recourse an undivided interest, adjusted daily, in up to $225 million of designated accounts receivable through November 2010 based on the November 2005 amendment to this agreement. At December 31, 2005, PECO had sold a $225 million interest in accounts receivable, consisting of a $195 million interest in accounts receivable which PECO accounted for as a sale under SFAS No. 140, "Accounting for Transfers and Servicing of Financial Assets and Extinguishment of Liabilities—a Replacement of FASB Statement No. 125," (SFAS No. 140), and a $30 million interest in special-agreement accounts receivable which was accounted for as a long-term note payable (see Note 11—Long-Term Debt). At December 31, 2004, PECO had sold a $225 million interest in accounts receivable, consisting of a $179 million interest in accounts receivable which PECO accounted for as a sale under SFAS No. 140 and a $46 million interest in special-agreement accounts receivable which was accounted for as a long-term note payable and reflected on the consolidated balance sheets as long-term debt due within one year. PECO retains the servicing responsibility for these receivables. The agreement requires PECO to maintain the $225 million interest, which, if not met, requires cash, which would otherwise be received by PECO under this program, to be held in escrow until the requirement is met. At December 31, 2005 and 2004, PECO met this requirement and was not required to make any cash deposits.

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

6. Property, Plant and Equipment

The following table presents a summary of property, plant and equipment by asset category as of December 31, 2005 and 2004:

Asset Category	December 31, 2005	December 31, 2004
Electric—transmission and distribution	$14,156	$13,479
Electric—generation	7,286	7,125
Gas—transmission and distribution	1,482	1,436
Common	476	501
Nuclear fuel	3,148	2,926
Construction work in progress	840	593
Asset retirement cost [(a)]	827	1,024
Other property, plant and equipment [(b)]	1,638	1,627
Total property, plant and equipment	29,853	28,711
Less accumulated depreciation [(c)]	7,872	7,229
Property, plant and equipment, net	$21,981	$21,482

(a) See Note 13—Asset Retirement Obligation and Spent Nuclear Fuel and Note 14—Conditional ARO for further information.
(b) Includes buildings under capital lease with a net carrying value of $40 million and $43 million at December 31, 2005 and 2004, respectively. The original cost basis of the buildings was $53 million and total accumulated amortization was $13 million and $10 million at December 31, 2005 and 2004, respectively.
(c) Includes accumulated amortization of nuclear fuel of $2,103 million and $1,976 million at December 31, 2005 and 2004, respectively.

As of December 31, 2005 and 2004, Exelon had recorded the following accumulated depreciation for regulated and unregulated property, plant and equipment:

	December 31, 2005		December 31, 2004	
	Regulated	Unregulated	Regulated	Unregulated
Accumulated depreciation	$3,425	$4,447	$3,173	$4,056

Regulatory Accounting. ComEd's and PECO's depreciation expense, which is included in cost of service for rate purposes, includes the estimated cost of dismantling and removing plant from service upon retirement. For ComEd, removal costs reduce the related regulated liability. For PECO, removal costs are capitalized when incurred and depreciated over the life of the new asset constructed consistent with PECO's regulatory recovery method. For more information, see Note 21—Supplemental Financial Information.

Service Life Extensions. Upon the December 2003 acquisition of the remaining 50% interest in AmerGen, Generation changed its accounting estimates related to the depreciation of certain AmerGen generating facilities to conform with Generation's depreciation policies. See Note 4—Regulatory Issues for further information on service life extensions.

License Renewals. Depreciation provisions are based on the estimated useful lives of the stations, which assumes the renewal of the licenses for all nuclear generating stations. As a result, the receipt of license renewals has no impact on the Consolidated Statements of Income. See Note 4—Regulatory Issues for further information on license renewals.

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

7. Jointly Owned Electric Utility Plant

Exelon's undivided ownership interests in jointly owned electric plant at December 31, 2005 and 2004 were as follows:

	Nuclear generation			Fossil fuel generation			
	Quad Cities	Peach Bottom	Salem (a)	Keystone	Conemaugh	Wyman	Transmission/ Other
Operator	Generation	Generation	PSEG Nuclear	Reliant	Reliant	FP&L	(b),(c)
Ownership interest	75.00%	50.00%	42.59%	20.99%	20.72%	5.89%	(b),(c)
Exelon's share at December 31, 2005:							
Plant	$ 363	$ 449	$ 181	$ 171	$ 217	$ 2	$62
Accumulated depreciation	67	241	42	107	138	1	28
Construction work in progress	51	22	78	5	1	—	—
Exelon's share at December 31, 2004:							
Plant	$ 287	$ 438	$ 127	$ 167	$ 212	$ 2	$62
Accumulated depreciation	54	231	33	102	133	—	27
Construction work in progress	39	16	81	5	1	—	—

(a) Generation also owns a proportionate share in the fossil fuel combustion turbine, which is fully depreciated. The gross book value was $3 million at December 31, 2005 and 2004.
(b) PECO has a 22.00% ownership of 127 miles of 500,000 voltage lines located in Pennsylvania and a 42.55% ownership of 151 miles of 500,000 voltage lines located in Delaware and New Jersey.
(c) Generation has a 44.24% ownership interest in Merrill Creek Reservoir located in New Jersey with a book value of $1 million at December 31, 2005 and 2004.

Exelon's undivided ownership interests are financed with its funds and all operations are accounted for as if such participating interests were wholly owned facilities. Exelon's share of direct expenses of the jointly owned plants are included in the corresponding operating expenses on Exelon's Consolidated Statements of Income.

8. Intangible Assets

Goodwill

Pursuant to SFAS No. 142, goodwill is not amortized; however, goodwill is subject to an assessment for impairment at least annually, or more frequently, if events or circumstances indicate that goodwill might be impaired. The impairment assessment is performed using a two-step, fair-value based test. The first step compares the fair value of the reporting unit to its carrying amount, including goodwill. If the carrying amount of the reporting unit exceeds its fair value, the second step is performed. The second step requires unrecognized intangible assets to be valued and then compares the carrying amount of the goodwill to the estimated fair value of the goodwill. If the fair value of goodwill is less than the carrying amount, an impairment loss is reported as a reduction to goodwill and a charge to operating expense.

Exelon has determined that the goodwill should have been assigned to a ComEd reporting unit as opposed to an Energy Delivery reporting unit as previously reported. As a result, Exelon assesses goodwill impairment at its ComEd reporting unit; accordingly, any goodwill impairment charge at ComEd will affect Exelon's results of operations as the goodwill impairment test for Exelon considers the cash flows of only ComEd.

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

The changes in the carrying amount of goodwill for the years ended December 31, 2005 and 2004 were as follows:

Balance as of January 1, 2004 [(a)]	$ 4,719
Resolution of certain tax matters [(b)]	(9)
PECO / Unicom Merger severance adjustments	(5)
Balance as of January 1, 2005 [(a)]	4,705
Resolution of certain tax matters	(23)
Impairment	(1,207)
Balance as of December 31, 2005 [(a)]	$ 3,475

(a) Exelon's goodwill balance at January 1, 2004, January 1, 2005 and December 31, 2005 is held at ComEd. See Note 22—Segment Information for further information regarding Exelon's segments.
(b) Adjustment related to income tax refund claims and interest thereon. See Note 20—Commitments and Contingencies for further information.

2005 Annual Goodwill Impairment Assessment. The annual goodwill impairment assessment was performed as of November 1, 2005. The first step of the annual impairment analysis, comparing the fair value of ComEd, the reporting unit that holds all of Exelon's goodwill, to its carrying value, including goodwill, indicated an impairment of goodwill existed. The second step of the analysis indicated ComEd's goodwill was impaired by $1.2 billion. This impairment was primarily driven by the fair value of ComEd's below market PPA with Generation, the end of ComEd's regulatory transition period at December 31, 2006 and the elimination of related transition revenues, developments in the regulatory and political environment as of November 1, 2005, anticipated increases in capital expenditures in future years and decreases in market valuations of comparable companies that are used to estimate the fair value of ComEd. In its assessment to estimate the fair value of the ComEd reporting unit, Exelon used a probability-weighted, discounted cash flow model with multiple scenarios. The determination of the fair value was dependent on many sensitive, interrelated and uncertain variables including changing interest rates, utility sector market performance, capital structure, market prices for power, post 2006 rate regulatory structures, operating and capital expenditure requirements and other factors.

Changes from the assumptions used in the impairment review could possibly result in a future impairment loss of ComEd's goodwill, which could be material. Illinois legislation provides that reductions to ComEd's common equity resulting from goodwill impairments will have no impact on the determination of the rate cap on ComEd's allowed equity return during the electricity industry restructuring transition period through 2006. See Note 4—Regulatory Issues for further discussion of ComEd's earnings provisions.

2004 Annual Goodwill Impairment Assessment. The annual goodwill impairment assessment was performed as of November 1, 2004. The first step of the annual impairment analysis, comparing the fair value of a reporting unit to its carrying value, including goodwill, indicated no impairment of goodwill at ComEd. In its assessment to estimate the fair value of their reporting unit, Exelon used a probability-weighted, discounted cash flow models with multiple scenarios. The determination of the fair value was dependent on many sensitive, interrelated and uncertain variables including changing interest rates, utility sector market performance, capital structure, market prices for power, post 2006 rate regulatory structures, operating and capital expenditure requirements and other factors.

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

Other Intangible Assets

Exelon's other intangible assets, included in deferred debits and other assets, consisted of the following:

	December 31, 2005			December 31, 2004		
	Gross	Accumulated Amortization	Net	Gross	Accumulated Amortization	Net
Amortized intangible assets:						
Energy purchase agreement [(a)]	$—	$ —	$—	$384	$(27)	$357
Tolling agreement [(a)]	—	—	—	73	(5)	68
Synthetic fuel investments [(b)]	264	(121)	143	264	(56)	208
Other	—	—	—	6	(6)	—
Total amortized intangible assets	264	(121)	143	727	(94)	633
Other intangible assets:						
Intangible pension asset	34	—	34	171	—	171
Total intangible assets	$298	$(121)	$177	$898	$(94)	$804

(a) These intangible assets were eliminated from Exelon's Consolidated Balance Sheets upon the sale of Sithe on January 31, 2005. See Note 3—Acquisitions and Dispositions for further information regarding the sale of Sithe.
(b) See Note 12—Income Taxes for a description of Exelon's right to acquire tax credits through investments in synthetic fuel-producing facilities.

In 2005, the intangible pension asset decreased by $137 million as a result of an annual actuarial valuation associated with Exelon's pension plans. See Note 15—Retirement Benefits for additional information. For the year ended December 31, 2005, Exelon's amortization expense related to intangible assets was $68 million, of which $4 million has been reflected as a reduction in revenues related to the energy purchase agreement and the tolling agreement. For the year ended December 31, 2004, Exelon's amortization expense related to intangible assets was $90 million, of which $32 million has been reflected as a reduction in revenues related to the energy purchase agreement and the tolling agreement. Exelon's amortization expense was not significant in 2003. Generation sold Sithe on January 31, 2005, which resulted in the elimination of the intangible assets related to Sithe's energy purchase agreement and tolling agreement from Exelon's Consolidated Balance Sheets. See Note 3—Acquisitions and Dispositions for further information regarding this sale. Exelon's amortization expense associated with intangible assets related to its investments in synthetic fuel-producing facilities is expected to be in the range of $72 million to $77 million annually for 2006 and 2007.

9. Severance Accounting

Exelon provides severance and health and welfare benefits to terminated employees pursuant to pre-existing severance plans primarily based upon each individual employee's years of service and compensation level. Exelon accounts for their ongoing severance plans in accordance with SFAS No. 112 and SFAS No. 88 and accrues amounts associated with severance benefits that are considered probable and that can be reasonably estimated.

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

The following tables present total salary continuance severance costs (benefits), recorded as an operating and maintenance expense, during 2005, 2004 and 2003:

Salary Continuance Severance	ComEd	PECO	Generation	Other [(a)]	Exelon
Expense (income) recorded—2005	(9)[(b)]	1	(4)[(b) (c)]	(2)[(b)]	$ (14)[(b)(c)]
Expense recorded—2004	10	3	2	17	32
Expense recorded—2003	61	16	38	20	135

(a) Other includes corporate operations, shared service entities, including Exelon Business Services Company (BSC), Enterprises and investments in synthetic fuel-producing facilities.
(b) Represents a reduction in previously recorded severance reserves.
(c) Excludes severance charges of $5 million related to Salem, of which Generation owns 42.59% and which is operated by PSEG Nuclear, LLC (PSEG Nuclear).

The following table provides a roll forward of the salary continuance severance obligations from January 1, 2004 through December 31, 2005:

Salary Continuance Obligations	
Balance at January 1, 2004	$139
Severance charges recorded	32
Cash payments	(87)
Other adjustments	(15)
Balance at January 1, 2005	$ 69
Reduction in obligation estimate	(14)[(a)]
Cash payments	(33)
Balance at December 31, 2005	$ 22

(a) Excludes severance charges of $5 million related to Salem, of which Generation owns 42.59% and which is operated by PSEG Nuclear.

10. Notes Payable and Short-Term Debt

	2005	2004	2003
Average borrowings	$ 935	$ 149	$ 144
Maximum borrowings outstanding	2,416	622	1,288
Average interest rates, computed on a daily basis	3.49%	1.37%	1.25%
Average interest rates, at December 31	4.59%	2.43%	1.08%

On March 7, 2005, Exelon entered into a $2 billion term loan agreement. The loan proceeds were used to fund discretionary contributions of $2 billion to Exelon's pension plans. On April 1, 2005, Exelon entered into a $500 million term loan agreement to reduce this $2 billion term loan. During the second quarter of 2005, $200 million of this $500 million term loan, as well as the remaining $1.5 billion balance on the $2 billion term loan described above, were repaid with the net proceeds received from the issuance of the $1.7 billion long-term senior notes presented in the table below. The $300 million outstanding balance under the $500 million term loan agreement bears interest at a variable rate determined, at Exelon's option, by either the Base Rate or the Eurodollar Rate (as defined in the term loan agreement). On November 30, 2005, the term loan agreement was amended and restated to extend the agreement from December 1, 2005 to September 16, 2006.

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

At December 31, 2003, Exelon, along with ComEd, PECO and Generation, participated with a group of banks in a $750 million 364-day unsecured revolving credit agreement and a $750 million three-year unsecured revolving credit agreement. On July 16, 2004, the $750 million 364-day facility was replaced with a $1 billion unsecured revolving facility maturing on July 16, 2009, and the $750 million three-year facility was reduced to $500 million maturing on October 31, 2006. Both revolving credit agreements are used principally to support the commercial paper programs at Exelon, ComEd, PECO and Generation and to issue letters of credit.

At December 31, 2005, Exelon, ComEd, PECO and Generation had the following sublimits and available capacity under the credit agreements and the indicated amounts of outstanding commercial paper:

Borrower	Bank Sublimit (a)	Available Capacity (b)	Outstanding Commercial Paper
Exelon	$100	$100	$ —
ComEd	650	623	459
PECO	350	350	220
Generation	400	353	311

(a) Sublimits under the credit agreements can change upon written notification to the bank group.
(b) Available capacity represents the bank sublimit net of outstanding letters of credit. The amount of commercial paper outstanding does not reduce the available capacity under the credit facilities.

Interest rates on advances under the credit facilities are based on either prime or the London Interbank Offering Rate (LIBOR) plus an adder based on the credit rating of the borrower as well as the total outstanding amounts under the agreement at the time of borrowing. The maximum LIBOR adder is 170 basis points.

The credit agreements require Exelon, ComEd, PECO and Generation to maintain a minimum cash from operations to interest expense ratio for the twelve-month period ended on the last day of any quarter. The ratios exclude revenues and interest expenses attributable to securitization debt, certain changes in working capital, distributions on preferred securities of subsidiaries and, in the case of Exelon and Generation, revenues from Sithe and interest on the debt of its project subsidiaries. The following table summarizes the minimum thresholds reflected in the credit agreements for the year ended December 31, 2005:

	Exelon	ComEd	PECO	Generation
Credit agreement threshold	2.65 to 1	2.25 to 1	2.25 to 1	3.25 to 1

At December 31, 2005, Exelon, ComEd, PECO and Generation were in compliance with the foregoing thresholds.

On February 10 through 13, 2006, Generation entered into separate additional credit facilities with aggregate bank commitments of $875 million. See Note 25—Subsequent Events for further information.

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

11. Long-Term Debt

	Rates	Maturity Date	December 31, 2005	December 31, 2004
Long-term debt				
First Mortgage Bonds [(a)] [(b)]:				
Fixed rates	3.50%-8.375%	2006-2033	$3,201	$3,510
Floating rates	2.95%-3.40%	2012-2020	497	406
Notes payable and other [(c)]	4.45%-7.83%	2006-2035	3,928	2,411
Pollution control notes:				
Floating rates	3.03%-3.55%	2016-2034	520	520
Notes payable—accounts receivable agreement	4.23%	2010	30	46
Sinking fund debentures	3.875%-4.75%	2008-2011	10	12
Sithe long-term debt [(d)]				
Non-recourse project debt				
Independence	8.50%-9.00%	2007-2013	—	499
Batavia	18.00%	2007	—	1
Subordinated debt	7.00%	2034	—	419
Total long-term debt [(e)]			8,186	7,824
Unamortized debt discount and premium, net			(19)	(114)
Fair-value hedge carrying value adjustment, net			(1)	9
Long-term debt due within one year			(407)	(427)
Long-term debt			$7,759	$7,292
Long-term debt due to ComEd Transitional Funding Trust and PECO Energy Transition Trust [(f)] [(g)]				
Payable to ComEd Transitional Funding Trust	5.44%-5.74%	2006-2008	$ 988	$1,341
Payable to PETT	6.05%-7.65%	2006-2010	2,975	3,456
Long-term debt due to ComEd Transitional Funding Trust and PECO Energy Transition Trust			3,963	4,797
Long-term debt due to ComEd Transitional Funding Trust and PECO Energy Transition Trust due within one year			(507)	(486)
Total long-term debt due to ComEd Transitional Funding Trust and PECO Energy Transition Trust			$3,456	$4,311
Long-term debt to other financing trusts (f) (g)				
Subordinated debentures to ComEd Financing II	8.50%	2027	155	155
Subordinated debentures to ComEd Financing III	6.35%	2033	206	206
Subordinated debentures to PECO Trust III	7.38%	2028	81	81
Subordinated debentures to PECO Trust IV	5.75%	2033	103	103
Total long-term debt to other financing trusts			$ 545	$ 545

(a) Utility plant of ComEd and PECO is subject to the liens of their respective mortgage indentures.
(b) Includes first mortgage bonds issued under the ComEd and PECO mortgage indentures securing pollution control bonds and notes.
(c) Includes capital lease obligations of $46 and $50 million at December 31, 2005 and 2004, respectively. Lease payments of $2 million, $2 million, $2 million, $2 million, $2 million and $36 million will be made in 2006, 2007, 2008, 2009, 2010 and thereafter, respectively.
(d) These amounts were removed from Exelon's consolidated balance sheets following Generation's sale of Sithe, which was completed on January 31, 2005. See Note 3—Acquisitions and Dispositions for further information. Prior to the sale, in addition to the stated interest rate, an additional 1.97% and 0.99% of interest on the carrying amount of the secured bonds payable was being credited due to debt premiums and 1.63% of interest on the carrying amount of the subordinated debt

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discount was being incurred due to the debt discount recorded at the time of purchase. At December 31, 2004, there was $100 million of unamortized debt discount associated with Sithe long-term debt.

(e) Long-term debt maturities in the periods 2006 through 2010 and thereafter are as follows:

Year	
2006	$ 407
2007	231
2008	898
2009	28
2010	645
Thereafter	5,977
Total	$8,186

(f) Effective July 1, 2003, PECO Trust IV, a financing subsidiary created in May 2003, was deconsolidated from the financial statements in conjunction with the adoption of FIN 46. Effective December 31, 2003, ComEd Financing II, ComEd Financing III, ComEd Transitional Funding Trust, PECO Trust III, and PETT were deconsolidated from the financial statements in conjunction with the adoption of FIN 46-R. Amounts owed to these financing trusts are recorded as debt to financing trusts within Exelon's Consolidated Balance Sheets.

(g) Long-term debt to financing trusts maturities in the periods 2006 through 2010 and thereafter are as follows:

Year	
2006	$ 506
2007	986
2008	965
2009	700
2010	806
Thereafter	545
Total	$4,508

Issuances of Long-Term Debt. The following long-term debt was issued during 2005:

Company	Type	Interest Rate	Maturity	Amount
Exelon	Senior notes	4.45%	June 15, 2010	$ 400
Exelon	Senior notes	4.90%	June 15, 2015	800
Exelon	Senior notes	5.625%	June 15, 2035	500
ComEd	Pollution Control Revenue Bonds	Variable	March 1, 2017	91
Total issuances (a)				$1,791

(a) Issuances exclude unamortized bond discounts of $3 million.

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

Debt Retirements and Redemptions. The following debt was retired, through tender, open market purchases, optional redemption or payment at maturity, during 2005:

Company	Type	Interest Rate	Maturity	Amount
Exelon	Notes payable for investments in synthetic fuel-producing facilities	6.00 to 8.00%	January 2008	$ 62
ComEd	Pollution Control Revenue Bonds	6.75%	March 1, 2015	91
ComEd	First Mortgage Bonds	9.875%	June 15, 2020	54
ComEd	First Mortgage Bonds	7.00%	July 1, 2005	163
ComEd	Notes Payable	6.40%	October 15, 2005	107
Other				31
Total retirements				$508

Debt totaling approximately $820 million was eliminated from Exelon's Consolidated Balance Sheets as a result of the sale of Sithe on January 31, 2005. See Note 3—Acquisitions and Dispositions for further discussion regarding the sale of Sithe.

During 2005 and 2004, ComEd made scheduled payments of $354 million and $335 million, respectively, related to its obligation to the ComEd Transitional Funding Trust, and PECO made scheduled payments of $481 million and $393 million, respectively, related to its obligation to PETT.

Prepayment premiums of $2 million, unamortized discount of $2 million and debt issuance costs of $1 million associated with the early retirement of debt in 2005 have been deferred in Exelon's regulatory assets and will be amortized to interest expense over the life of the related new debt issuance consistent with regulatory recovery.

See Note 16—Fair Value of Financial Assets and Liabilities for additional information regarding interest-rate swaps.

See Note 17—Preferred Securities for additional information regarding preferred stock.

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12. Income Taxes

Exelon's income tax expense (benefit) from continuing operations is comprised of the following components:

	For the Years Ended December 31,		
	2005	2004	2003
Included in operations:			
Federal			
Current	$376	$406	$282
Deferred	411	260	127
Investment tax credit amortization	(13)	(13)	(13)
State			
Current	86	86	78
Deferred	84	(26)	(85)
Total income tax expense	$944	$713	$389
Included in cumulative effect of changes in accounting principles:			
Deferred			
Federal	$ (22)	$ 12	$ 58
State	(5)	5	11
Total income tax expense (benefit)	(27)	$ 17	$ 69

Exelon's effective income tax rate from continuing operations varies from the U.S. Federal statutory rate principally due to the following:

	For the Years Ended December 31,		
	2005	2004	2003
U.S. Federal statutory rate	35.0%	35.0%	35.0%
Increase (decrease) due to:			
State income taxes, net of Federal income tax benefit	5.8	1.6	(0.5)
Nondeductible goodwill impairment charge [c]	22.3	—	—
Synthetic fuel-producing facilities credit [a] [b]	(12.6)	(8.4)	(1.8)
Qualified nuclear decommissioning trust fund income	0.8	(0.3)	0.7
Manufacturer's deduction	(0.8)	—	—
Tax exempt income	(0.6)	(0.4)	(0.6)
Nontaxable postretirement benefits	(0.6)	(0.3)	—
Amortization of investment tax credit	(0.5)	(0.4)	(0.8)
Low income housing credit	—	(0.4)	(1.1)
Other	1.0	1.3	(0.7)
Effective income tax rate	49.8%	27.7%	30.2%

(a) Change between 2005 and 2004 reflects ownership of all synthetic fuel-producing facilities for the full year in 2005 compared to five months in 2004.

(b) Change between 2004 and 2003 reflects investments in synthetic fuel-producing facilities made in the fourth quarter of 2003 and the third quarter of 2004. See Note 3—Acquisitions and Dispositions for additional information regarding investments in synthetic fuel-producing facilities.

(c) Change in effective income tax rate between 2005 and 2004 is primarily due to the goodwill impairment charge of $1.2 billion.

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The tax effects of temporary differences giving rise to significant portions of Exelon's deferred tax assets and liabilities as of December 31, 2005 and 2004 are presented below:

	2005	2004
Deferred tax liabilities:		
Plant basis difference	$(4,291)	$(4,178)
Stranded cost recovery	(1,465)	(1,632)
Deferred debt refinancing costs	(49)	(56)
Total deferred tax liabilities	(5,805)	(5,866)
Deferred tax assets:		
Deferred pension and postretirement obligations	396	985
Excess of tax value over book value of impaired assets [(a)]	41	44
Decommissioning and decontamination obligations	105	145
Unrealized loss on derivative financial instruments	195	57
Goodwill	6	6
Other, net	326	209
Total deferred tax assets	1,069	1,446
Deferred income tax liabilities (net) on the Consolidated Balance Sheets	$(4,736)	$(4,420)

(a) Includes write-downs of certain Enterprises investments.

In accordance with regulatory treatment of certain temporary differences, Exelon has recorded a net regulatory asset associated with deferred income taxes, pursuant to SFAS No. 71 and SFAS No. 109, of $789 million and $751 million at December 31, 2005 and 2004, respectively. See Note 21—Supplemental Financial Information for further discussion of Exelon's regulatory asset associated with deferred income taxes.

ComEd and PECO have certain tax returns that are under review at the audit or appeals level of the IRS, and certain state authorities. Except for the tax positions discussed below, these reviews by governmental taxing authorities are not expected to have an adverse impact on the financial condition or result of operations of Exelon.

At December 31, 2005 and 2004, Exelon had recorded valuation allowances of $6 million and $9 million, with respect to deferred taxes associated with separate company state taxes. As of December 31, 2005, Exelon had net capital loss carryforwards for income tax purposes of approximately $129 million, which will expire after 2008.

Investments in Synthetic Fuel-Producing Facilities

Background. Exelon, through three separate wholly owned subsidiaries, owns interests in two limited liability companies and one limited partnership that own synthetic fuel-producing facilities. These facilities chemically convert coal, including waste and marginal coal, into a synthetic fuel which is used at power plants. Section 45k (formerly Section 29) of the Internal Revenue Code (IRC) provides tax credits for the sale of synthetic fuel produced from coal. These tax credits are scheduled to expire in December 2007. The expenses associated with the operations of these facilities exceed the related operating revenues and, therefore, these facilities generate operating losses. However, the tax credits provided by Section 45k of the IRC and the tax benefit related to the operating losses have historically more than offset the operating losses. The value of the Section 45k tax credits is adjusted annually by an inflation factor published by the Internal Revenue Service (IRS) in April of the year following the year in which the credits are earned. Exelon's right to acquire tax credits generated by the facilities was recorded as intangible assets which are amortized as the tax credits are earned.

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

Ownership Structure. The purchase price for Exelon's investments in synthetic fuel-producing facilities is comprised of fixed and variable components. The fixed component is in the form of a non-recourse note that requires nonrefundable quarterly payments of principal and interest to the sellers. The variable component is based on the value of estimated tax credits that will be allocated to Exelon. Exelon's subsidiaries are also required to make capital contributions based on the allocated amount of tax credits to the operators to fund the operating losses.

Phase-Out of Credits Based on Crude Oil Prices. Section 45k of the IRC contains a provision under which the tax credits are phased out (i.e., eliminated) in the event crude oil prices for a year exceed certain thresholds. Pursuant to Section 45k of the IRC, the value of the tax credit in a given year begins to be reduced if the annual average price per barrel of oil according to the First Purchaser index (Reference Price) within the year exceeds the threshold of the IRC-prescribed inflation-adjusted phase-out range. The tax credit is completely phased out if the Reference Price exceeds the maximum amount of the phase-out range. Given that the Reference Price is based on the current year's annual average price, this amount must be estimated throughout the year based on actual prices to date. Recent events, such as terrorism, natural disasters and strong worldwide demand, have significantly increased the price of domestic crude oil and, therefore, have created uncertainty as to the value of future synthetic fuel tax credits.

The following table (in dollars) provides the actual and estimated phase-out prices per barrel of oil and the annual Reference Price for 2004 and 2005 in terms of the First Purchaser index:

	Actual 2004	Estimated 2005
Beginning of Phase-Out Range	$51	$52[(a)]
End of Phase-Out Range	64	66[(a)]
Annual Reference Price	37	51

(a) Estimated phase-out ranges are calculated using inflation rates published by the IRS after year end. The inflation rate used by Exelon to estimate the 2005 phase-out range was 2%.

As indicated in the table above, there was no phase-out of tax credits during 2004 since the annual oil Reference Price in terms of the First Purchaser index of $37 did not exceed the beginning phase-out price of $51. It is also not expected that there will be a phase-out for 2005 as the estimated reference price of $51 did not exceed the beginning of the estimated phase-out range of $52.

In order to assess the likelihood of a phase-out of tax credits and a potential impairment of the related intangible assets for 2005, Exelon must estimate the phase-out prices and the Reference Price based on actual prices to date. Actual prices to date are not readily available for the First Purchaser index which, as mentioned above, is prescribed by the IRS to calculate the Reference Price. In addition, the First Purchaser index does not include monthly quoted oil futures prices. As such, Exelon uses the New York Mercantile Exchange, Inc. index (NYMEX) to estimate an annual reference price. There are, however, certain pricing differences between the First Purchaser index and the NYMEX. The First Purchaser index includes prices for high sulfur, medium sulfur and low sulfur crude. The

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NYMEX pricing is based on low sulfur crude only. Additionally, the First Purchaser index is based on wellhead pricing with no transportation cost component. The NYMEX pricing carries a delivery cost. There are also certain regional pricing differences between the First Purchaser index and NYMEX. Despite these pricing differences, Exelon believes the NYMEX provides a reasonable estimate of the annual Reference Price.

The following table (in dollars) provides the actual and estimated phase-out prices per barrel of oil and the annual reference price in NYMEX terms for 2005.

	Estimated 2005
Beginning of Phase-Out Range [(a)]	$58
End of Phase-Out Range [(a)]	73
2005 Annual Average NYMEX	57

(a) Estimated phase-out ranges are calculated using inflation rates published by the IRS after year end. The inflation rate used by Exelon to estimate the 2005 phase-out range was 2%.

Based on the table above, the estimated annual phase-out threshold price based on the NYMEX would have to exceed $58 in 2005 for a phase-out to begin. Through December 31, 2005, the NYMEX closing price of a barrel of oil has averaged $57. Therefore, as of December 31, 2005, Exelon estimates that it will not exceed the threshold for a phase out of tax credits in 2005.

Impact on Financial Statements. Exelon's interests in synthetic fuel-producing facilities, including mark-to-market gains, increased Exelon's net income by $81 million and $70 million during 2005 and 2004, respectively. The increase in net income is reflected in the Consolidated Statements of Income as a benefit within income taxes, partially offset by charges to operating and maintenance expense, depreciation and amortization expense, interest expense and equity in losses of unconsolidated affiliates.

The net carrying value of the intangible assets was $143 million and $208 million at December 31, 2005 and 2004, respectively. See Note 8—Intangible Assets for additional information. The rising price of oil has resulted in the need to evaluate the intangible assets for impairment. An impairment of the intangible assets would occur if Exelon estimates that the synthetic fuel-producing facilities will not generate sufficient cash flows to cover the intangible assets balance as a result of tax credits being phased-out. A decision by the plant operators to cease operating the facilities could also result in the intangible assets being impaired. Based on the current available information, Exelon believes the operators will not cease to operate the facilities in 2006 and 2007. The intangible assets were not impaired as a result of the 2006 and 2007 average NYMEX future prices at December 31, 2005. If the intangible assets were to be impaired and the plants were to cease operations, Exelon would potentially be relieved of remaining payments on the non-recourse notes payable and would record a gain upon legal extinguishment of the notes payable for the remaining outstanding balance. However, this would occur in a period subsequent to the impairment being recorded.

The non-recourse notes payable principal balance was $158 million and $220 million at December 31, 2005 and 2004, respectively.

1999 Sale of Fossil Generating Assets

Exelon, through its ComEd subsidiary, has taken certain tax positions, which have been disclosed to the IRS, to defer the tax gain on the 1999 sale of its fossil generating assets. As of December 31, 2005 and 2004, deferred tax liabilities related to the fossil plant sale are reflected in Exelon's

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Consolidated Balance Sheets with the majority allocated to ComEd and the remainder to Generation. Exelon's ability to continue to defer all or a portion of this liability depends on whether its treatment of the sales proceeds as having been received in connection with an involuntary conversion is proper pursuant to applicable law. Exelon's ability to continue to defer the remainder of this liability may depend in part on whether its tax characterization of a lease transaction ComEd entered into in connection with the sale is proper pursuant to applicable law. For instance, the IRS may argue that the lease transaction is of a type it has recently announced its intention to challenge, and Exelon understands that somewhat similar transactions entered into by other companies have been the subject of review and challenge by the IRS. A successful IRS challenge to ComEd's positions would have the impact of accelerating future income tax payments and increasing interest expense related to the deferred tax gain that becomes currently payable. As of December 31, 2005, Exelon's potential cash outflow, including tax and interest (after tax), could be as much as $951 million. If the deferral were successfully challenged by the IRS, it could negatively impact Exelon's results of operations by as much as $135 million (after tax). Exelon's management believes a reserve for interest has been appropriately recorded in accordance with FASB Statement No. 5, "Accounting for Contingencies" (SFAS No. 5); however, the ultimate outcome of such matters could result in unfavorable or favorable adjustments to the results of operations, and such adjustments could be material. Federal tax returns covering the period of the 1999 sale are currently under IRS audit. Final resolution of this matter is not anticipated for several years.

13. Nuclear Decommissioning and Spent Fuel Storage

Exelon has a legal obligation to decommission its nuclear power plants following the expiration of their operating licenses. Exelon will pay for this obligation using trust funds that have been established for this purpose. These trust funds have been funded through prior and current collections from customers. The trust funds established for a particular plant may not be used to fund the decommissioning obligation of any other nuclear plant. Exelon believes that these funds, along with future collections from customers for decommissioning, will ultimately be sufficient to satisfy all required decommissioning-related activities.

The following table summarizes the most significant assets and liabilities associated with nuclear decommissioning included in Exelon's Consolidated Balance Sheets as of December 31, 2005 and 2004:

December 31, 2005	
Property, plant and equipment (asset retirement cost)	$ 685
Nuclear decommissioning trust funds	5,585
Regulatory liability	(1,503)
Asset retirement obligation	(3,921)
Other comprehensive income, net	(76)
December 31, 2004	
Property, plant and equipment (asset retirement cost)	$ 961
Nuclear decommissioning trust funds	5,262
Regulatory liability	(1,479)
Asset retirement obligation	(3,981)
Other comprehensive income, net	(62)

Nuclear Decommissioning Obligations

Generation assumed the responsibility for decommissioning the former ComEd and former PECO nuclear units as a result of a corporate restructuring effective January 1, 2001 in which Exelon separated its generation and other competitive businesses from its regulated energy delivery business at ComEd and PECO.

AmerGen, which became a wholly owned subsidiary of Generation in December 2003, assumed responsibility for decommissioning the Three Mile Island, Clinton and Oyster Creek units upon the original purchase of each unit in 1999, 1999 and 2000, respectively.

Generation will begin decommissioning activities for each plant once that plant ceases operations. The majority of Generation's decommissioning activity is anticipated to begin after 2029. Generation currently makes decommissioning payments for its retired units; however, those amounts are not considered significant when compared to the total obligation.

As of December 31, 2005 and 2004, Exelon had recorded nuclear decommissioning obligations totaling $3,921 million and $3,981 million, respectively, which were determined in accordance with SFAS No. 143. See Note 1—Significant Accounting Policies for information regarding the adoption and application of SFAS No. 143.

Nuclear Decommissioning Trust Funds

The trust funds that have been established to satisfy Exelon's nuclear decommissioning obligations were originally funded with amounts collected by customers. In certain circumstances, these trust funds will continue to be funded by future collections from customers.

The trusts associated with the former ComEd units and the former PECO units have been funded with amounts collected from the ComEd and PECO customers, respectively. Any funds remaining in these trusts after decommissioning has been completed are required to be refunded to ComEd or PECO's customers as appropriate. Conversely, if there are insufficient funds in the trusts associated with the former ComEd units to pay for decommissioning costs, Generation is required to fund that shortfall. Any potential shortfall is determined on a plant-by-plant basis, since the trust funds established for any particular plant may not be used to fund the decommissioning obligations of any other plant.

If there are insufficient funds in the trusts associated with the former PECO units, PECO is allowed to collect additional amounts from the PECO customers, subject to certain limitations, 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 compared to decommissioning obligations, as well as 5% of any additional shortfalls. This initial $50 million will be borne by Generation as required by the corporate restructuring in 2001. Accordingly, the order from the PAPUC currently allows PECO to seek additional collections to fund 95% of the shortfall, after the initial $50 million that is not eligible for reimbursement from the customers.

AmerGen is financially responsible for the decommissioning of the AmerGen plants and retains any funds remaining in the trusts after decommissioning of those plants has been completed. Any shortfall of funds necessary for decommissioning is required to be funded by AmerGen.

As of December 31, 2005 and 2004, nuclear decommissioning trust funds totaled $5,585 million and $5,262 million, respectively. See Note 16—Fair Value of Financial Assets and Liabilities for more information regarding the nuclear decommissioning trust funds as of December 31, 2005 and 2004.

Current Collections from Customers

Through 2006, ComEd is permitted to collect up to $73 million annually from customers to pay for decommissioning costs. These amounts are collected by ComEd and remitted to Generation on a monthly basis. In 2005 and 2004, ComEd collected and remitted to Generation a total of $68 million and $73 million, respectively. ComEd is not permitted to collect any amounts after 2006 to pay for decommissioning costs; accordingly, any trust fund deficiencies, as determined on a plant-by-plant basis, for decommissioning obligations related to the former ComEd plants will be funded by Generation.

PECO is permitted to collect amounts to fund decommissioning costs through the retirement dates of each of the former PECO nuclear units. Currently, PECO collects $33 million annually from customers to pay for these decommissioning costs. These amounts are collected by PECO and remitted to Generation on a monthly basis. Every five years, the PAPUC reviews the annual amount that PECO is allowed to collect from customers. In both 2005 and 2004, PECO collected and remitted to Generation $33 million. In the event the PAPUC reduces or eliminates the amount PECO is permitted to collect from customers, Generation anticipates that any trust fund deficiencies for decommissioning obligations related to the former PECO plants would be funded by Generation.

AmerGen does not currently collect any amounts from customers, nor is there any mechanism by which Generation can seek to collect additional amounts from customers in order to pay the decommissioning costs of the AmerGen units.

Accounting Implications of the Agreements with ComEd and PECO

Impact on the Statements of Income

As discussed above, the ComEd and PECO customers are entitled to a refund of any excess, as determined on a plant-by-plant basis, of trust funds that remain after the completion of decommissioning activities. Because the funds held in trust currently exceed the total estimated decommissioning obligation, Exelon does not recognize in the statement of income the net impacts of decommissioning the former ComEd and former PECO units. However, should the decommissioning obligations associated with the former ComEd units exceed the related decommissioning assets, Exelon will no longer maintain a regulatory liability to ComEd customers, but rather reflect the net impacts of decommissioning activities related to these plants in the statements of income.

Decommissioning impacts, including the accretion of the decommissioning obligation (which is included in operating and maintenance expense in the statements of income) and the income of the trust funds (net of applicable taxes) associated with the former ComEd and former PECO units, are offset within the statements of income with an equal adjustment to the regulatory liability. The decommissioning of the AmerGen units are reflected in the statements of income, as there are no regulatory agreements associated with these units.

Impact on the Statements of Other Comprehensive Income

Exelon does not reflect any net activity within the statement of other comprehensive income related to the unrealized gains and losses for the trust funds established to fund the decommissioning liabilities of the former PECO units as these unrealized gains and losses are not anticipated to ultimately be included in the statement of income as a result of the current accounting discussed above. Unrealized gains and losses (after applicable taxes) related to the former ComEd units are also offset within the statement of other comprehensive income. The gross unrealized gains and losses in the trust funds of the former ComEd and PECO units are tax-effected at the applicable tax rates, so that the associated deferred tax assets and liabilities can be appropriately calculated and recorded.

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The net unrealized gains and losses associated with AmerGen are included in the statement of other comprehensive income, since the accounting treatment described above does not apply to AmerGen.

Impact on the Balance Sheet

The decommissioning liabilities associated with the former ComEd, former PECO and AmerGen units are reflected as an asset retirement obligation (ARO) in the long-term liability section of the balance sheet. AROs represent legal obligations associated with the retirement of tangible long-lived assets. Changes in the ARO resulting from revisions to the timing or amount of future undiscounted cash flows are generally recognized through a corresponding increase or decrease to the carrying value of that plant. This adjustment is reflected in property, plant and equipment as an asset retirement cost (ARC), and is amortized on a straight-line basis over the life of that plant. The adjustments that are required to eliminate the decommissioning impacts on the statement of income and statement of other comprehensive income associated with the former ComEd and PECO plants are recorded through changes in regulatory liabilities.

The following table provides a roll forward of the ARO on Exelon's Consolidated Balance Sheets, from January 1, 2004 to December 31, 2005:

Asset retirement obligation at January 1, 2004 (a)	$2,997
Net increase resulting from updates to estimated future cash flows	780
Accretion expense	210
Additional liabilities incurred (b)	6
Payments to decommission retired plants	(12)
Asset retirement obligation at December 31, 2004 (a)	3,981
Net decrease resulting from updates to estimated future cash flows	(281)
Accretion expense	243
Liability reclassified and disposed (c)	(8)
Payments to decommission retired plants	(14)
Asset retirement obligation at December 31, 2005	$3,921

(a) Includes amounts not related to nuclear decommissioning.
(b) Additional liabilities incurred are primarily due to the consolidation of Sithe.
(c) Represents the reclassification of $(5) million primarily related to fossil and hydroelectric generating facilities and $(3) million related to liabilities disposed as a result of the sale of Sithe on January 31, 2005.

2005 and 2004 ARO Updates

In 2005, Exelon recorded a $281 million net decrease in the ARO resulting from revisions to estimated future nuclear decommissioning cash flows. This decrease resulted primarily from a year-over-year decline in the cost escalation factors used to estimate future undiscounted costs, partially offset by an increase resulting from updated decommissioning cost studies received for two nuclear stations. Both the updated cost escalation factors and the updated cost studies were provided by independent third-party appraisers.

In 2004, Exelon recorded a $780 million net increase in the ARO resulting from revisions to estimated future nuclear decommissioning cash flows. This increase resulted primarily from updated decommissioning cost studies and changes in cost escalation factors used to estimate future undiscounted costs, both of which were provided by independent third-party appraisers.

Spent Nuclear Fuel

Under the Nuclear Waste Policy Act of 1982 (NWPA), the U.S. Department of Energy (DOE) is responsible for the development of a repository for the disposal of spent nuclear fuel (SNF) and high-level radioactive waste. As required by the NWPA, Generation is a party to contracts with the DOE (Standard Contracts) to provide for disposal of SNF from its nuclear generating stations. In accordance with the NWPA and the Standard Contracts, Generation pays the DOE one mill ($.001) per kilowatt-hour of net nuclear generation for the cost of nuclear fuel long-term disposal. This fee may be adjusted prospectively in order to ensure full cost recovery. The NWPA and the Standard Contracts required the DOE to begin taking possession of SNF generated by nuclear generating units by no later than January 31, 1998. The DOE, however, failed to meet that deadline and its performance will be delayed significantly. The DOE's current estimate for opening a SNF facility is 2012. This extended delay in SNF acceptance by the DOE has led to Generation's adoption of dry cask storage at its Dresden, Quad Cities, Oyster Creek and Peach Bottom stations and its consideration of dry cask storage at other stations.

The Standard Contracts with the DOE also required the payment to the DOE of a one-time fee applicable to nuclear generation through April 6, 1983. PECO's fee has been paid. Pursuant to the Standard Contracts, ComEd elected to pay the one-time fee of $277 million, with interest to the date of payment, just prior to the first delivery of SNF to the DOE. As of December 31, 2005, the unfunded liability for the one-time fee with interest was $906 million. Interest accrues at the 13-week Treasury Rate. The 13-week Treasury Rate in effect, for calculation of the interest accrual at December 31, 2005, was 3.983%. The liabilities for spent nuclear fuel disposal costs, including the one-time fee, were transferred to Generation as part of the 2001 corporate restructuring. The one-time fee obligation for the AmerGen units, except for Clinton, remains with the prior owner. Clinton has no outstanding obligation.

In July 1998, ComEd filed a complaint against the United States Government (Government) in the United States Court of Federal Claims (Court) seeking to recover damages caused by the DOE's failure to honor its contractual obligation to begin disposing of SNF in January 1998. In August 2001, the Court granted ComEd's motion for partial summary judgment for liability on ComEd's breach of contract claim. In November 2001, the Government filed two partial summary judgment motions relating to certain damage issues in the case as well as two motions to dismiss claims other than ComEd's breach of contract claim. On June 10, 2003, the Court granted the Government's motion to dismiss claims other than the breach of contract claims. Also on June 10, 2003, the Court denied the Government's summary judgment motions and set the case for trial on damages for November 2004.

In July 2000, PECO entered into an agreement (Amendment) with the DOE relating to PECO's Peach Bottom nuclear generating unit to address the DOE's failure to begin removal of SNF in January

1998 as required by the Standard Contracts. Under the Amendment, the DOE agreed to provide PECO with credits against PECO's future contributions to the Nuclear Waste Fund to compensate PECO for SNF storage costs incurred as a result of the DOE's breach of the contract. The Amendment also provided that, upon PECO's request, the DOE will take title to the SNF and the interim storage facility at Peach Bottom provided certain conditions are met. Generation assumed this contract in the 2001 corporate restructuring.

In November 2000, eight utilities with nuclear power plants filed a Joint Petition for Review against the DOE with the United States Court of Appeals for the Eleventh Circuit seeking to invalidate that portion of the Amendment providing for credits to PECO against nuclear waste fund payments on the grounds that such provision is a violation of the NWPA. PECO intervened as a defendant in that case and Generation assumed the claim in the 2001 corporate restructuring. On September 24, 2002, the United States Court of Appeals for the Eleventh Circuit ruled that the fee adjustment provision of the Amendment violates the NWPA and therefore is null and void. The Court did not hold that the Amendment as a whole is invalid. Article XVI (I) of the Amendment provides that if any portion of the Amendment is found to be void, the DOE and Generation agree to negotiate in good faith and attempt to reach an enforceable agreement consistent with the spirit and purpose of the Amendment. That provision further provided that should a major term be declared void, and the DOE and Generation cannot reach a subsequent agreement, the entire Amendment would be rendered null and void, the original Peach Bottom Standard Contracts would remain in effect and the parties would return to pre-Amendment status. Under the Amendment, Generation has received approximately $40 million in credits against contributions to the nuclear waste fund.

On August 14, 2003, Generation received a letter from the DOE demanding repayment of $40 million of previously received credits from the Nuclear Waste Fund, which Generation paid in 2004. The letter also demanded $1.5 million of interest that was accrued as of that date and Generation continued to record an interest expense each subsequent month. Generation reserved its 50% ownership share of these amounts. Because Generation expenses the dry storage casks and capitalizes the permanent components of its spent fuel storage facilities, these reserves increased Generation's operating and maintenance expense approximately $11 million and its capital base approximately $9 million during 2003.

On July 21, 2004, Exelon and the U.S. Department of Justice, in close consultation with the DOE, reached a settlement under which the government will reimburse Generation for costs associated with storage of spent fuel at Generation's nuclear stations pending DOE's fulfillment of its obligations. Under the agreement, Generation immediately received $80 million in gross reimbursements for storage costs already incurred ($53 million net after considering amounts due from Generation to co-owners of certain nuclear stations), with additional amounts to be reimbursed annually for future costs. Also under the agreement, during the third quarter of 2004, Generation made full reimbursement of $41.9 million to the Nuclear Waste Fund for prior credits plus lost earnings as set forth in the DOE Contracting Officer's letter dated August 14, 2003. In 2005, Generation received $58 million in gross reimbursements for storage costs incurred between October 1, 2003 and June 30, 2005, ($35 million net, after considering amounts due from Generation to co-owners and previous owners of certain nuclear stations). As of December 31, 2005, the amount of spent fuel storage costs for which reimbursement will be requested from the DOE under the settlement agreement is $14 million gross, which is recorded within accounts receivable, other. This amount is comprised of $6 million, which has been recorded as a reduction to operating and maintenance expense, and $5 million, which has been recorded as a reduction to capital expenditures. The remaining $3 million represents amounts owed to the co-owners of the Peach Bottom and Quad Cities generating facilities. In all cases, reimbursements will be made only after costs are incurred and only for costs resulting from DOE delays in accepting the fuel.

14. Conditional ARO

As of December 31, 2005, Exelon adopted FIN 47, which clarified that a legal obligation associated with the retirement of a long-lived asset whose timing and/or method of settlement are conditional on a future event is within the scope of SFAS No. 143. Under FIN 47, Exelon is required to record liabilities associated with its conditional AROs at their estimated fair values if those fair values can be reasonably estimated.

Determination of Conditional AROs

The adoption of FIN 47 required Exelon to update an existing inventory, originally created for the adoption of SFAS No. 143, and to determine which, if any, of the conditional AROs could be reasonably estimated. The significant conditional AROs identified by ComEd and PECO included abatement and disposal of equipment and buildings contaminated with asbestos and Polychlorinated Biphenyls (PCBs). The significant conditional AROs identified by Generation included plant closure costs associated with its fossil and hydroelectric generating stations, including asbestos abatement, removal of certain storage tanks and other decommissioning-related activities.

The ability to reasonably estimate a conditional ARO was a matter of management judgment, based upon management's ability to estimate a settlement date or range of settlement dates, a method or potential method of settlement and probabilities associated with the potential dates and methods of settlement of its conditional AROs. In determining whether their conditional AROs could be reasonably estimated, management considered Exelon's past practices, industry practices, management's intent and the estimated economic lives of the assets. The management of Exelon concluded that all significant conditional AROs could be reasonably estimated.

Exelon was required to measure the conditional AROs at fair value using the methodology prescribed by FIN 47. The transition provisions of FIN 47 required Exelon to apply this measurement back to the historical periods in which the conditional AROs were incurred, resulting in a remeasurement of these obligations at the latter of the date that the related assets were placed into service or acquired or the date that the applicable law or environmental regulation became effective. The fair values of the conditional AROs were then estimated using a probability-weighted, discounted cash flow model with multiple scenarios, if applicable. The present value of future estimated cash flows was calculated using credit-adjusted, risk-free rates in order to determine the fair value of the conditional AROs at the time of adoption of FIN 47.

Conditional AROs of $231 million were recorded as of December 31, 2005. Changes in management's assumptions regarding settlement dates, settlement methods or assigned probabilities could have had a material effect on the liabilities recorded at December 31, 2005 as well as the associated cumulative effect of a change in accounting principle and associated regulatory assets recorded.

Effect of Adopting FIN 47

FIN 47 required that Exelon recognize the following amounts within its financial statements upon the adoption of FIN 47: (i) a liability for any existing conditional AROs adjusted for cumulative accretion to December 31, 2005; (ii) an ARC capitalized as an increase to the carrying amount of the associated long-lived assets; and (iii) cumulative depreciation on the ARC. The transition guidance in FIN 47 required that its adoption be effected through a cumulative change in accounting principle measured as the difference between the amounts recognized in the financial statements prior to the adoption of FIN 47 for conditional AROs and the amounts recognized as of December 31, 2005 pursuant to FIN 47. Exelon had previously recognized $39 million as removal costs within regulatory liabilities associated with conditional AROs that were reclassified to a conditional ARO liability upon the adoption of FIN 47.

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

After considering the transitional guidance included in FIN 47, Exelon recorded a charge of $42 million (net of income taxes of $27 million) as a cumulative effect of a change in accounting principle in connection with its adoption. In addition, due to the application of SFAS No. 71, which is further described in Note 1—Significant Accounting Policies, Exelon recorded regulatory assets of $104 million associated with the adoption of FIN 47.

The following table presents the line items within Exelon's Consolidated Statements of Income for the year ended December 31, 2005 and the Consolidated Balance Sheets at December 31, 2005 that were affected by the adoption of FIN 47:

Consolidated statements of income line item:	
Cumulative effect of a change in accounting principle (net of income taxes of $(27)) [(a)]	$ (42)
Consolidated balance sheets line items—increase (decrease):	
Property, plant and equipment, net [(b)]	19
Regulatory assets [(c)]	13
Deferred income taxes (noncurrent liability)	(27)
Asset retirement obligations [(d)]	231
Regulatory liabilities [(e)]	(130)

(a) Represents the difference between the conditional ARO, net ARC and regulatory assets and liabilities recorded upon adoption, net of income taxes.
(b) Represents capitalized ARC of $52 million as an increase to the carrying amount of the associated long-lived assets, net of accumulated depreciation of $33 million on the ARC.
(c) Represents an increase to regulatory assets at PECO pursuant to SFAS No. 71 for amounts expected to be recovered from customers.
(d) Represents a liability for existing conditional AROs adjusted for cumulative accretion to December 31, 2005.
(e) Represents an increase to regulatory assets (which are netted with regulatory liabilities) at ComEd of $91 million pursuant to SFAS No. 71 for amounts expected to be recovered from customers and removal costs within regulatory liabilities of $39 million at ComEd that were reclassified to the asset retirement obligations liability.

See Note 1—Significant Accounting Policies for net income and earnings per common share for 2005, 2004 and 2003, adjusted as if FIN 47 had been applied effective during the entirety of those years. The following table presents, on a pro forma basis, what the liability for conditional AROs would have been had FIN 47 been applied during the years 2004 and 2003. These pro forma amounts are estimated based upon the information, assumptions, and interest rates used to measure the liability for conditional AROs recognized upon adoption of FIN 47 as of December 31, 2005.

Pro forma liability for conditional AROs, January 1, 2003 [(a)]	$196
Pro forma liability for conditional AROs, December 31, 2003 [(a)]	208
Pro forma liability for conditional AROs, December 31, 2004 [(a)]	221

(a) Includes AROs related to fossil and hydroelectric generating stations at Generation previously recorded upon the adoption of SFAS No. 143.

Prospective Accounting Methodology Under FIN 47

The liabilities associated with conditional AROs will be adjusted on an ongoing basis due to the passage of time, new laws and regulations and revisions to either the timing or amount of the original estimates of undiscounted cash flows. These adjustments could have a significant impact on Exelon's Consolidated Statements of Income and Consolidated Balance Sheets, assuming the provisions of SFAS No. 71 continue to apply.

The liabilities recorded as of December 31, 2005 related to the conditional AROs of Exelon will be accreted to their full estimated settlement amounts through the estimated ultimate settlement dates. For Generation, this accretion charge will be recorded as an operating and maintenance expense within the Consolidated Statements of Income. For ComEd and PECO, most of this accretion charge will be recorded as an increase to their regulatory assets due to the application of SFAS No. 71.

The net ARC recorded as of December 31, 2005 by Exelon will be depreciated over the remaining lives of the related long-lived assets. For Generation, this charge will be recorded as depreciation and amortization expense within the Consolidated Statements of Income. For ComEd and PECO, most of this depreciation charge will be recorded as an increase to their regulatory assets due to the application of SFAS No. 71.

15. Retirement Benefits

Exelon sponsors defined benefit pension plans and postretirement welfare benefit plans for essentially all ComEd, PECO, Generation (except for AmerGen) and BSC employees and certain employees of Enterprises. Substantially all non-union employees and electing union employees hired on or after January 1, 2001 participate in Exelon-sponsored cash balance pension plans. Substantially all non-union employees hired prior to January 1, 2001 were offered a choice to remain in Exelon's traditional pension plan or transfer to a cash balance pension plan for management employees. Employees of AmerGen participate in separate defined benefit pension plans and postretirement welfare benefit plans sponsored by AmerGen. In 2005, AmerGen offered its employees a choice to remain in their traditional benefit formula or convert to a cash balance formula. Exelon has not yet received a ruling with respect to its non-union plan due to the IRS temporary moratorium on issuing any ruling to plans that were involved in a "conversion" from a traditional to a cash balance formula.

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

Exelon made discretionary aggregate contributions of approximately $2 billion to its traditional and cash balance pension plans in 2005. These contributions were initially funded through borrowings under a short-term loan agreement, which were subsequently refinanced with long-term senior notes, as further described in Note 11—Long-Term Debt.

The funded status of the pension obligation refers to the difference between plan assets and estimated obligations of the plan. The funded status may change over time due to several factors, including contribution levels, assumed discount rates and assumed long-term rates of return on plan assets. Changes in these factors could impact the funded status of the pension obligation.

The following tables provide a roll forward of the changes in the benefit obligations and plan assets for the most recent two years:

	Pension Benefits		Other Postretirement Benefits	
	2005	2004	2005	2004
Change in benefit obligation:				
Net benefit obligation at beginning of year	$ 9,775	$8,758	$2,988	$3,019
Service cost	144	128	89	78
Interest cost	546	545	175	163
Plan participants' contributions	—	—	22	17
Plan amendments	5	—	(17)	(106)
Actuarial loss (gain)	351	964	239	(10)
Curtailments/settlements	—	(19)	—	—
Special accounting costs	—	—	—	16
Gross benefits paid	(574)	(601)	(199)	(189)
Net benefit obligation at end of year	$10,247	$9,775	$3,297	$2,988
Change in plan assets:				
Fair value of plan assets at beginning of year	$ 7,014	$6,442	$1,246	$1,171
Actual return on plan assets	612	723	58	115
Employer contributions	2,008	450	214	132
Plan participants' contributions	—	—	22	17
Gross benefits paid	(574)	(601)	(199)	(189)
Fair value of plan assets at end of year	$ 9,060	$7,014	$1,341	$1,246

The following table provides a reconciliation of benefit obligations, plan assets and funded status of the plans:

	Pension Benefits		Other Postretirement Benefits	
	2005	2004	2005	2004
Fair value of plan assets at end of year	$ 9,060	$ 7,014	$ 1,341	$ 1,246
Net benefit obligations at end of year	10,247	9,775	3,297	2,988
Funded status (plan assets less plan obligations)	(1,187)	(2,761)	(1,956)	(1,742)
Amounts not recognized				
Unrecognized net actuarial loss	3,339	2,954	1,245	1,046
Unrecognized prior service cost (benefit)	159	170	(370)	(445)
Unrecognized net transition obligation (asset)	—	(4)	67	76
Net amount recognized	$ 2,311	$ 359	$(1,014)	$(1,065)

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

The following table provides a reconciliation of the amounts recognized in the Consolidated Balance Sheets as of December 31, 2005 and 2004:

	Pension Benefits		Other Postretirement Benefits	
	2005	2004	2005	2004
Prepaid benefit cost	$ 2,358	$ 407	$ —	$ —
Accrued benefit cost	(47)	(48)	(1,014)	(1,065)
Additional minimum liability	(2,202)	(2,352)	—	—
Intangible asset	34	171	—	—
Accumulated other comprehensive income	2,168	2,181	—	—
Net amount recognized	$ 2,311	$ 359	$(1,014)	$(1,065)

The accumulated benefit obligation (ABO) for all defined benefit pension plans was $9,234 million and $9,006 million at December 31, 2005 and 2004, respectively. On an ABO basis, the plans were funded at 98% at December 31, 2005 compared to 78% at December 31, 2004. On a projected benefit obligation basis, the plans were funded at 88% at December 31, 2005 compared to 72% at December 31, 2004.

The following table provides the projected benefit obligation, ABO, and fair value of plan assets for pension plans with an ABO in excess of plan assets. The table below is also representative of all pension plans with a projected benefit obligation in excess of plan assets.

	December 31,	
	2005	2004
Projected benefit obligation	$9,457	$9,775
Accumulated benefit obligation	8,463	9,006
Fair value of plan assets	8,196	7,014

The following table provides the components of the net periodic benefit costs for the years ended December 31, 2005, 2004 and 2003. The table reflects an annualized reduction in 2005 and 2004 net periodic postretirement benefit cost of $40 million and $33 million, respectively, related to a Federal subsidy provided under the Prescription Drug Act. This subsidy has been accounted for under FSP FAS 106-2, as described in Note 1—Significant Accounting Policies. A portion of the net periodic benefit cost is capitalized within the Consolidated Balance Sheets.

	Pension Benefits			Other Postretirement Benefits		
	2005	2004	2003	2005	2004	2003
Service cost	$ 144	$ 128	$ 109	$ 89	$ 78	$ 68
Interest cost	546	545	519	175	163	167
Expected return on assets [(a)]	(767)	(611)	(584)	(98)	(90)	(75)
Amortization of:						
Transition obligation (asset)	(4)	(4)	(4)	9	10	10
Prior service cost	16	15	16	(91)	(81)	(54)
Actuarial loss	121	73	23	81	44	47
Curtailment/settlement charges	—	22	59	—	2	21
Net periodic benefit cost	$ 56	$ 168	$ 138	$165	$126	$184
Special termination benefits charge	$ —	$ —	$ —	$—	$ 16	$ 48
Other additional information:						
Increase (decrease) in other comprehensive income (net of tax)	$ 10	$(392)	$ 26	$—	$—	$—

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

(a) The increase in expected return on pension assets during 2005 compared to 2004 and 2003 was primarily attributable to discretionary pension contributions of $2 billion made during the first quarter of 2005.

Exelon's costs of providing pension and postretirement benefit plans are dependent upon a number of factors, such as the rates of return on pension plan assets, discount rate, and the rate of increase in health care costs. In 2003, the additional minimum liability was reduced by $69 million and shareholders' equity increased by $26 million (net of income taxes) as a result of an annual actuarial valuation associated with Exelon's pension plans. In 2004, the additional minimum pension liability was increased by $606 million and shareholders' equity decreased by $392 million (net of income taxes) as a result of an annual actuarial valuation associated with Exelon's pension plans. In 2005, the additional minimum pension liability was reduced by $150 million and shareholders' equity primarily increased by $10 million (net of income taxes) as a result of an annual actuarial valuation associated with Exelon's pension plans.

Special accounting costs of $0, $16 million and $48 million in 2005, 2004 and 2003, respectively, represent special health and welfare severance benefits offered to terminated employees. These costs were recorded pursuant to SFAS No. 112. Prior service cost is amortized on a straight-line basis over the average remaining service period of employees expected to receive benefits under the plans.

The following weighted average assumptions were used to determine the benefit obligations at December 31, 2005, 2004 and 2003:

	Pension Benefits			Other Postretirement Benefits		
	2005 (a)	2004	2003	2005 (a)	2004	2003
Discount rate	5.60%	5.75%	6.25%	5.60%	5.75%	6.25%
Rate of compensation increase	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%
Health care cost trend on covered charges	N/A	N/A	N/A	8.00% decreasing to ultimate trend of 5.0% in 2010	9.00% decreasing to ultimate trend of 5.0% in 2010	10.00% decreasing to ultimate trend of 4.5% in 2011

(a) Assumptions used to determine year-end 2005 benefit obligations will be the assumptions used to estimate the expected costs of benefits in 2006.

The following weighted average assumptions were used to determine the net periodic benefit costs for years ended December 31 2005, 2004 and 2003:

	Pension Benefits			Other Postretirement Benefits		
	2005	2004	2003	2005	2004	2003
Discount rate	5.75%	6.25%	6.60-6.75%	5.75%	6.25%	6.60-6.75%
Expected return on plan assets	9.00%	9.00%	9.00%	8.30%	8.33-8.35%	8.40%
Rate of compensation increase	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%
Health care cost trend on covered charges	N/A	N/A	N/A	9.00% decreasing to ultimate trend of 5.0% in 2010	10.00% decreasing to ultimate trend of 4.5% in 2011	8.50% decreasing to ultimate trend of 4.5% in 2008

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

In managing its pension and postretirement plan assets, Exelon utilizes a diversified, strategic asset allocation to efficiently and prudently generate investment returns that will meet the objectives of the investment trusts that hold the plan assets. Asset / Liability studies that incorporate specific plan objectives as well as assumptions regarding long-term capital market returns and volatilities generate the specific asset allocations for the trusts. In general, Exelon's investment strategy reflects the belief that over the long term, equities are expected to outperform fixed-income investments. The long-term nature of the trusts make them well suited to bear the risk of added volatility associated with equity securities, and, accordingly, the asset allocations of the trusts usually reflect a higher allocation to equities as compared to fixed-income securities. Non-U.S. equity securities are used to diversify some of the volatility of the U.S. equity market while providing comparable long-term returns. Alternative asset classes, such as private equity and real estate, may be utilized for additional diversification and return potential when appropriate. Exelon's investment guidelines limit exposure to investments in more volatile sectors.

Exelon generally maintains approximately 60% of its plan assets in equity securities and 40% of its plan assets in fixed-income securities. On a quarterly basis, Exelon reviews the actual asset allocations and follows a rebalancing procedure in order to remain within an allowable range of these targeted percentages.

In selecting the expected rate of return on plan assets, Exelon considers historical returns for the types of investments that its plans hold. Historical returns and volatilities are modeled to determine asset allocations that best meet the objectives of the asset / liability studies. These asset allocations, when viewed over a long-term historical view of the capital markets, yield an expected return on assets in excess of 9%.

Exelon's pension plan weighted average asset allocations at December 31, 2005 and 2004 and target allocation for 2005 were as follows:

		Percentage of Plan Assets at December 31,	
Asset Category	Target Allocation at December 31, 2005	2005	2004
Equity securities	60%	61%	63%
Debt securities	35-40	35	33
Real estate	0-5	4	4
Total		100%	100%

Exelon's other postretirement benefit plan weighted average asset allocations at December 31, 2005 and 2004 and target allocation for 2005 were as follows:

		Percentage of Plan Assets at December 31,	
Asset Category	Target Allocation at December 31, 2005	2005	2004
Equity securities	60-65%	63%	64%
Debt securities	35-40	35	34
Real estate	—	2	2
Total		100%	100%

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

Exelon's defined benefit pension plans and postretirement welfare benefit plans do not directly hold shares of Exelon common stock.

Assumed health care cost trend rates have a significant effect on the costs reported for the health care plans. A one percentage point change in assumed health care cost trend rates would have the following effects:

Effect of a one percentage point increase in assumed health care cost trend	
on total service and interest cost components	$ 41
on postretirement benefit obligation	399
Effect of a one percentage point decrease in assumed health care cost trend	
on total service and interest cost components	(30)
on postretirement benefit obligation	(297)

Estimated future benefit payments to participants in Exelon's pension plans and postretirement welfare benefit plans as of December 31, 2005 were:

	Pension Benefits	Other Postretirement Benefits [(a)]
2006	$ 553	$ 205
2007	555	219
2008	557	231
2009	560	242
2010	568	252
2011 through 2015	3,076	1,420
Total estimated future benefits payments through 2015	$5,869	$2,569

(a) Estimated future benefit payments do not reflect an anticipated Federal subsidy provided through the Prescription Drug Act. The Federal subsidies to be received by Exelon in the years 2006, 2007, 2008, 2009, 2010 and from 2011 through 2015 are estimated to be $8 million, $8 million, $9 million, $10 million, $11 million and $69 million, respectively.

Exelon sponsors savings plans for the majority of its employees. The plans allow employees to contribute a portion of their pre-tax income in accordance with specified guidelines. Exelon matches a percentage of the employee contribution up to certain limits. The cost of Exelon's matching contribution to the savings plans totaled $58 million, $57 million and $55 million in 2005, 2004 and 2003, respectively.

16. Fair Value of Financial Assets and Liabilities

Non-Derivative Financial Assets and Liabilities

Fair Value. As of December 31, 2005 and 2004, Exelon's carrying amounts of cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities are representative of fair value because of the short-term nature of these instruments. Fair values for long-term debt and preferred securities of subsidiaries are determined by an external valuation model which is based on conventional discounted cash flow methodology and utilizes assumptions of current market pricing curves.

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

The carrying amounts and fair values of Exelon's financial liabilities as of December 31, 2005 and 2004 were as follows:

	2005		2004	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt (including amounts due within one year)	$8,166	$8,231	$7,719	$8,372
Long-term debt to ComEd Transitional Funding Trust and PETT (including amounts due within one year)	3,963	4,132	4,797	5,182
Long-term debt to other financing trusts	545	539	545	573
Preferred securities of subsidiaries	87	70	87	69

Credit Risk. Financial instruments that potentially subject Exelon to concentrations of credit risk consist principally of cash equivalents and customer accounts receivable. Exelon places its cash equivalents with high-credit quality financial institutions. Generally, such investments are in excess of the Federal Deposit Insurance Corporation limits. Concentrations of credit risk with respect to customer accounts receivable are limited due to Exelon's large number of customers and, in the case of ComEd's and PECO's energy delivery businesses, their dispersion across many industries.

Exelon would also be exposed to credit-related losses in the event of non-performance by counterparties that issue derivative instruments. The credit exposure of derivative contracts is represented by the fair value of contracts at the reporting date. The notional amount of derivatives does not represent amounts that are exchanged by the parties and, thus, are not a measure of Exelon's exposure. The amounts exchanged are calculated on the basis of the notional or contract amounts, as well as on the other terms of the derivatives, which relate to interest rates and the volatility of these rates.

Interest-Rate Swaps

The fair values of Exelon's interest-rate swaps and purchase power and sale contracts are determined using quoted exchange prices, external dealer prices or internal valuation models which utilize assumptions of future energy prices and available market pricing curves. At December 31, 2005 and 2004, Exelon had $240 million and $440 million, respectively, of notional amounts of interest-rate swaps outstanding. At December 31, 2005 and 2004, net deferred gains (losses) associated with the interest-rate swaps were as follows:

	Notional Amount	Exelon Pays	Counterparty Pays	Fair Value 12/31/05	Fair Value 12/31/04
Fair-Value Hedges					
ComEd	$240	3 Month LIBOR plus 1.12% –1.60%	6.15%	$ (1)	$ 9
Cash-Flow Hedges					
Exelon	200	4.59% – 4.65%	3 Month LIBOR	—	2
Net Deferred Gains (Losses)				$ (1)	$11

Fair-Value Hedges. Exelon utilizes fixed-to-floating interest-rate swaps as a means to achieve its targeted level of variable-rate debt as a percent of total debt. At December 31, 2005, Exelon had $240 million of notional amounts of fair-value hedges outstanding. The swaps have been designated as fair-value hedges, as defined in SFAS No. 133, "Accounting for Derivatives and Hedging Activities" (SFAS No. 133), and, as such, changes in the fair value of the swaps are recorded in earnings; however, as long as the hedge remains effective and the underlying transaction remains probable, changes in the fair value of the swaps are offset by changes in the fair value of the hedged liabilities. Any change in the fair value of the hedge as a result of ineffectiveness is recorded immediately in earnings.

During 2004, Exelon settled interest-rate swaps in aggregate notional amounts of $485 million and recorded a net pre-tax gain of $26 million, which is being amortized as a reduction to interest expense over the remaining life of the related debt. Exelon did not have any amount excluded from the measure of effectiveness for the years ended December 31, 2005 or 2004.

Cash-Flow Hedges. Exelon utilizes interest rate derivatives to lock in interest-rate levels in anticipation of future financings. Forward-starting interest-rate swaps are designated as cash-flow hedges, as defined in SFAS No. 133 and, as such, changes in the fair value of the swaps are recorded in accumulated other comprehensive income (OCI). Any change in the fair value of the hedge as a result of ineffectiveness is recorded immediately in earnings. At December 31, 2005, Exelon did not have any notional amounts of cash-flow hedges outstanding. During 2005, Exelon settled interest-rate swaps in the aggregate notional amount of $1.8 billion, of which $325 million was the result of a forecasted transaction no longer being probable, and recorded pre-tax losses of $54 million, of which $15 million was included in other, net within Exelon's Consolidated Statements of Income. Exelon is recording the remaining $39 million as additional interest expense over the remaining life of the related debt.

During 2004, Exelon settled $315 million of interest-rate swaps in aggregate notional amounts of and recorded net pre-tax gains of $1 million which is being amortized over the lives of the related debt. In addition, during 2004, Exelon recorded income of $0.2 million which represented the ineffective portions of changes in the fair value of cash-flow hedge positions. This amount was associated with the settlement of interest-rate swaps in December 2004 and was included in other, net on Exelon's Consolidated Statements of Income. Exelon did not reclassify any amounts from accumulated OCI into earnings as a result of financing transactions no longer being probable during the year ended December 31, 2004.

Energy-Related Derivatives

Generation utilizes derivatives to manage the utilization of its available generating capacity and the provision of wholesale energy to its affiliates. Exelon also utilizes energy option contracts and energy financial swap arrangements to limit the market price risk associated with forward energy commodity contracts. Additionally, Generation enters into certain energy-related derivatives for trading or speculative purposes. Generation's energy contracts are accounted for under SFAS No. 133. Non-trading contracts may qualify for the normal purchases and normal sales exemption to SFAS No. 133 discussed in the "Management's Discussion and Analysis of Financial Condition and Results of Operation—Critical Accounting Policies and Estimates." Those that do not meet the normal purchase and normal sales exemption are recorded as assets or liabilities on the balance sheet at fair value. Changes in the derivatives recorded at fair value are recognized in earnings unless specific hedge accounting criteria are met and they are designated as cash-flow hedges, in which case those changes are recorded in OCI, and gains and losses are recognized in earnings when the underlying transaction occurs. Changes in the fair value of derivative contracts that do not meet the hedge criteria under SFAS No. 133 (or are not designated as such) and proprietary trading contracts are recognized in current earnings. Generation also has contracted for access to additional generation and sales to load-serving entities that are accounted for under the accrual method of accounting discussed in Note 20—Commitments and Contingencies.

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

At December 31, 2005, Exelon had net liabilities of $516 million on its Consolidated Balance Sheets for the fair value of energy derivatives, which included the energy derivatives discussed below. The following tables provide a summary of the fair value balances recorded by Exelon as of December 31, 2005:

December 31, 2005	Generation					
Derivatives	Cash-Flow Hedges	Other Derivatives	Proprietary Trading	Subtotal	Other [(a)] Derivatives	Exelon Energy-Related Derivatives [(b)]
Current assets	$ 563	$ 327	$ 26	$ 916	$—	$ 916
Noncurrent assets	153	9	124	286	24	310
Total mark-to-market energy contract assets	$ 716	$ 336	$ 150	$ 1,202	$ 24	$ 1,226
Current liabilities	$ (948)	$(316)	$ (18)	$(1,282)	$—	$(1,282)
Noncurrent liabilities	(289)	(48)	(123)	(460)	—	(460)
Total mark-to-market energy contract liabilities	$(1,237)	$(364)	$(141)	$(1,742)	$—	$(1,742)
Total mark-to-market energy contract net assets (liabilities)	$ (521)	$ (28)	$ 9	$ (540)	$ 24	$ (516)

(a) Other includes corporate operations, shared service entities, including Exelon Business Services Company (BSC), Enterprises and investments in synthetic fuel-producing facilities.
(b) Excludes Exelon's interest-rate swaps.

At December 31, 2004, Exelon had net liabilities of $145 million on its Consolidated Balance Sheets for the fair value of energy derivatives, which included the energy derivatives discussed below. The following table provides a summary of the fair value balances recorded by Exelon at December 31, 2004:

December 31, 2004	Generation					
Derivatives	Cash-Flow Hedges	Other Derivatives	Proprietary Trading	Subtotal	Other [(a)] Derivatives	Exelon Energy-Related Derivatives [(b)]
Current assets	$ 295	$ 106	$ 2	$ 403	$—	$ 403
Noncurrent assets	132	240	1	373	—	373
Total mark-to-market energy contract assets	$ 427	$ 346	$ 3	$ 776	$—	$ 776
Current liabilities	$(489)	$(109)	$—	$(598)	$—	$(598)
Noncurrent liabilities	(162)	(161)	—	(323)	—	(323)
Total mark-to-market energy contract liabilities	$(651)	$(270)	$—	$(921)	$—	$(921)
Total mark-to-market energy contract net assets (liabilities)	$(224)	$ 76	$ 3	$(145)	$—	$(145)

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

(a) Other includes corporate operations, shared service entities, including Exelon Business Services Company (BSC), Enterprises and investments in synthetic fuel-producing facilities.
(b) Excludes Exelon's interest-rate swaps.

Normal Operations and Hedging Activities. Electricity available from Generation's owned or contracted generation supply in excess of Generation's obligations to customers, including ComEd's and PECO's retail load, is sold into the wholesale markets. To reduce price risk caused by market fluctuations, Generation enters into physical contracts as well as derivative contracts, including forwards, futures, swaps and options, with approved counterparties to hedge anticipated exposures.

Cash-Flow Hedges

The tables below provide details of effective cash-flow hedges under SFAS No. 133 included on Exelon's Consolidated Balance Sheets as of December 31, 2005. The data in the table is indicative of the magnitude of SFAS No. 133 hedges Generation has in place; however, since under SFAS No. 133 not all derivatives are recorded in OCI, the table does not provide an all-encompassing picture of Generation's derivatives. The tables also include a rollforward of accumulated OCI related to cash-flow hedges for the years ended December 31, 2005 and 2004, providing information about the changes in the fair value of hedges and the reclassification from OCI into earnings.

December 31, 2005	Total Cash-Flow Hedge OCI Activity, Net of Income Tax
Accumulated OCI derivative loss at January 1, 2005	$(137)
Changes in fair value	(533)
Reclassifications from OCI to net income	356
Accumulated OCI derivative loss at December 31, 2005	$(314)

December 31, 2004	Total Cash-Flow Hedge OCI Activity, Net of Income Tax
Accumulated OCI derivative loss at January 1, 2004	$(133)
Changes in fair value	(312)
Disposal of existing Boston Generating contracts	16
Reclassifications from OCI to net income	290
Exelon Energy Company opening balance	2
Accumulated OCI derivative loss at December 31, 2004	$(137)

At December 31, 2005, Generation had net unrealized pre-tax losses of $521 million of cash-flow hedges recorded in accumulated OCI. Based on market prices at December 31, 2005, approximately $386 million of these deferred net pre-tax unrealized losses on derivative instruments in accumulated OCI are expected to be reclassified to earnings during the next twelve months. However, the actual amount reclassified to earnings could vary due to future changes in market prices. Amounts recorded in accumulated OCI related to changes in energy commodity cash-flow hedges are reclassified into earnings when the forecasted purchase or sale of the energy commodity occurs. The majority of Generation's cash-flow hedges are expected to settle within the next three years.

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

Generation's cash-flow hedge activity impact to Exelon's pre-tax earnings based on the reclassification adjustment from accumulated OCI to earnings was a $583 million pre-tax loss, a $475 million pre-tax loss and a $273 million pre-tax loss for the years ended December 31, 2005, 2004 and 2003 respectively.

Other Derivatives

Generation enters into certain contracts that are derivatives, but do not qualify for hedge accounting under SFAS No. 133 or are not designated as cash-flow hedges. These contracts are also entered into to economically hedge and limit the market price risk associated with energy commodity prices. Changes in the fair value of these derivative contracts are recognized in current earnings. For 2005, 2004, and 2003, Exelon recognized the following net unrealized mark-to-market gains, realized mark-to-market losses and total mark-to-market gains (losses) (before income taxes) relating to mark-to-market activity of certain non-trading purchase power and sale contracts pursuant to SFAS No. 133. Mark-to-market activity on non-trading purchase power and sale contracts are reported in fuel and purchased power.

	For the Year Ended December 31,		
	2005	2004	2003
Unrealized mark-to-market gains	$110	$ 181	$ 207
Realized mark-to-market losses	(98)	(183)	(223)
Total net mark-to-market gains (losses)	$ 12	$ (2)	$ (16)

Proprietary Trading Activities. Proprietary trading includes all contracts entered into purely to profit from market price changes as opposed to hedging an exposure and is subject to limits established by the Risk Management Committee. These contracts are recognized on the balance sheet at fair value and changes in the fair value of these derivative financial instruments are recognized in earnings. The proprietary trading activities are a complement to Generation's energy marketing portfolio but represent a very small portion of Generation's overall energy marketing activities. For 2005, 2004 and 2003, Exelon recognized the following net unrealized mark-to-market gains, realized mark-to-market gains (losses) and total mark-to-market gains (before income taxes) relating to mark-to-market activity on derivative instruments entered into for trading purposes. Gains and losses associated with financial trading are reported as revenue in Exelon's Consolidated Statements of Income.

	For the Year Ended December 31,		
	2005	2004	2003
Unrealized mark-to-market gains (losses)	$18	$ 3	$(3)
Realized mark-to-market gains (losses)	(3)	(3)	4
Total net mark-to-market gains	$15	$—	$ 1

Exelon Energy has entered into a limited number of energy commodity derivative contracts in connection with its service of gas customers. Prior to January 1, 2004, contracts were maintained by Exelon Energy. While the majority of these contracts qualify as normal purchases and sales or as cash-flow hedges under SFAS No. 133, $15 million was recorded as an increase to fuel expense in 2003 primarily as a result of the reversal of the 2002 mark-to-market adjustments.

Credit Risk Associated with Derivative Instruments. Exelon would be exposed to credit-related losses in the event of non-performance by counterparties that issue derivative instruments. The credit exposure of derivatives contracts is represented by the fair value of contracts at the reporting date. For energy-related derivative instruments, Generation has entered into payment netting agreements or enabling agreements that allow for payment netting with the majority of its large counterparties, which reduce Generation's exposure to counterparty risk by providing for the offset of amounts payable to the counterparty against amounts receivable from the counterparty. The notional amount of derivatives does not represent amounts that are exchanged by the parties and, thus, is not a measure of Exelon's exposure. The amounts exchanged are calculated on the basis of the notional or contract amounts, as well as on the other terms of the derivatives, which relate to interest rates and the volatility of these rates.

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

Nuclear Decommissioning Trust Fund Investments

Investments as of December 31, 2005 and 2004. Exelon classifies investments in trust accounts for decommissioning nuclear plants as available-for-sale and estimates their fair value based on quoted market prices for the securities held in trust funds. These investments are held to fund Generation's decommissioning obligation for its nuclear plants. Decommissioning expenditures are expected to occur primarily after the plants are retired. Based on current licenses and anticipated renewals, decommissioning expenditures for plants in operation are currently estimated to begin after 2029. See Note 13—Nuclear Decommissioning and Spent Fuel Storage for further information regarding the decommissioning of Generation's nuclear plants.

The following tables show the fair values, gross unrealized gains and losses and amortized cost bases of the securities held in these trust accounts as of December 31, 2005 and 2004:

	December 31, 2005			
	Amortized Cost	Gross Unrealized Gains	Gross Unrealized Losses	Estimated Fair Value
Cash and cash equivalents	$ 80	$—	$—	$ 80
Marketable equity securities	2,762	683	(32)	3,413
U.S. Treasury obligations and direct obligations of U.S. government agencies	361	32	(6)	387
Other debt securities	1,695	19	(9)	1,705
Total available-for-sale securities	$4,898	$734	$(47)	$5,585

	December 31, 2004			
	Amortized Cost	Gross Unrealized Gains	Gross Unrealized Losses	Estimated Fair Value
Cash and cash equivalents	$ 184	$—	$—	$ 184
Equity securities	2,194	538	(37)	2,695
U.S. Treasury obligations and direct obligations of U.S. government agencies	1,447	51	(4)	1,494
Other debt securities	855	37	(3)	889
Total available-for-sale securities	$4,680	$626	$(44)	$5,262

The fixed-income available-for-sale securities held at December 31, 2005 have an average maturity range of seven to ten years. The cost of these securities was determined on the basis of specific identification.

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

Impairment Evaluation in 2005. At December 31, 2005, Exelon had gross unrealized gains of $734 million and gross unrealized losses of $47 million related to the nuclear decommissioning trust fund investments. At December 31, 2004, Exelon had gross unrealized gains of $626 million and gross unrealized losses of $44 million related to the nuclear decommissioning trust fund investments. With the exception of the portion of these amounts primarily related to AmerGen and as a result of ComEd's and PECO's regulatory arrangements for decommissioning costs, approximately $556 million and $469 million of these net unrealized gains were recorded as an increase to regulatory liabilities as of December 31, 2005 and 2004, respectively.

Exelon evaluates decommissioning trust fund investments for other-than-temporary impairments by analyzing the historical performance, cost basis and market value of securities in unrealized loss positions in comparison to related market indices. Exelon evaluates whether certain trust fund investments are other-than-temporarily impaired based on various factors assessed in the aggregate, including the duration and severity of the impairment, the anticipated recovery of the securities and considerations of Generation's ability and intent to hold the investments until the recovery of their cost basis. This evaluation resulted in a $2 million and $8 million impairment charge recorded in other income and deductions associated with the decommissioning trust funds of the AmerGen plants during the years ended December 31, 2005 and 2004, respectively. Also, Exelon realized $20 million and $260 million of impairment charges associated with the trust funds for the decommissioning of the former ComEd and former PECO plants during the years ended December 31, 2005 and 2004, respectively. Recognition of these impairment charges associated with the former ComEd and former PECO plants had no net income impact on Exelon's results of operations or financial position.

Unrealized Gains and Losses. Net unrealized gains of $687 million and $582 million were included in regulatory liabilities or accumulated other comprehensive income in Exelon's Consolidated Balance Sheets at December 31, 2005 and 2004, respectively.

The following table provides information regarding available-for-sale securities held in nuclear decommissioning trust funds in an unrealized loss position that were not considered other-than-temporarily impaired. The following tables show the investments' gross unrealized losses and fair value, aggregated by investment category and length of time that individual securities have been in a continuous unrealized loss position, at December 31, 2005 and 2004.

	December 31, 2005					
	Less than 12 months		12 months or more		Total	
	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses
Marketable equity securities	$ 345	$(23)	$ 69	$ (9)	$ 414	$(32)
U.S. Treasury obligations and direct obligations of U.S. government agencies	433	(5)	28	(1)	461	(6)
Other debt securities	275	(5)	73	(4)	348	(9)
Total	$1,053	$(33)	$170	$(14)	$1,223	$(47)

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

	December 31, 2004					
	Less than 12 months		12 months or more		Total	
	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses
Marketable equity securities	$197	$(16)	$278	$(21)	$475	$(37)
U.S. Treasury obligations and direct obligations of U.S. government agencies	207	(2)	68	(2)	275	(4)
Other debt securities	182	(2)	22	(1)	204	(3)
Total	$586	$(20)	$368	$(24)	$954	$(44)

Exelon evaluates the historical performance, cost basis and market value of securities in unrealized loss positions in comparison to related market indices to assess whether or not the securities are other-than-temporarily impaired. Exelon concluded that the trending of the related market indices, the historical performance of these securities over a long-term time horizon and the level of insignificance of the unrealized loss as a percentage of the cost of the individual securities indicates that the securities are not other-than-temporarily impaired.

Sale of Nuclear Decommissioning Trust Fund Investments. Proceeds from the sale of decommissioning trust fund investments and gross realized gains and losses on those sales for the years ended December 31, 2005, 2004 and 2003 were as follows:

	For the Years Ended December 31,		
	2005	2004	2003
Proceeds from sales	$5,274	$2,320	$2,341
Gross realized gains	130	115	219
Gross realized losses	(81)	(43)	(235)

17. Preferred Securities

At December 31, 2005 and 2004, Exelon was authorized to issue up to 100,000,000 shares of preferred stock, none of which was outstanding.

Preferred and Preference Stock of Subsidiaries

At December 31, 2005 and 2004, ComEd prior preferred stock and ComEd cumulative preference stock consisted of 850,000 shares and 6,810,451 shares authorized, respectively, none of which was outstanding.

At December 31, 2005 and 2004, cumulative preferred stock of PECO, no par value, consisted of 15,000,000 shares authorized and the outstanding amounts set forth below. Shares of preferred stock have full voting rights, including the right to cumulate votes in the election of directors.

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

	Current Redemption Price [a]	December 31, 2005	December 31, 2004	December 31, 2005	December 31, 2004
		Shares Outstanding		Dollar Amount	
Series (without mandatory redemption)					
$4.68 (Series D)	$104.00	150,000	150,000	$15	$15
$4.40 (Series C)	112.50	274,720	274,720	27	27
$4.30 (Series B)	102.00	150,000	150,000	15	15
$3.80 (Series A)	106.00	300,000	300,000	30	30
Total preferred stock		874,720	874,720	$87	$87

(a) Redeemable, at the option of PECO, at the indicated dollar amounts per share, plus accrued dividends.

18. Common Stock

At December 31, 2005 and 2004, Exelon's common stock without par value consisted of 2,000,000,000 and 1,200,000,000 shares authorized, respectively, and 666,369,787 and 664,187,996 shares outstanding, respectively.

Stock Split

On January 27, 2004, the Board of Directors of Exelon approved a 2-for-1 stock split of Exelon's common stock. The distribution date was May 5, 2004. The share and per-share amounts have been adjusted for all periods presented to reflect the stock split.

Share Repurchases

Share Repurchase Program. In April 2004, Exelon's Board of Directors approved a discretionary share repurchase program that allows Exelon to repurchase shares of its common stock on a periodic basis in the open market. The share repurchase program is intended to mitigate, in part, the dilutive effect of shares issued under Exelon's employee stock option plan and Exelon's Employee Stock Purchase Plan (ESPP). The aggregate value of the shares of common stock repurchased pursuant to the program cannot exceed the economic benefit received after January 1, 2004 due to stock option exercises and share purchases pursuant to Exelon's ESPP. The economic benefit consists of the direct cash proceeds from purchases of stock and the tax benefits associated with exercises of stock options. The share repurchase program has no specified limit on the number of shares that may be repurchased and no specified termination date. Any shares repurchased are held as treasury shares unless cancelled or reissued at the discretion of Exelon's management. Treasury shares are recorded at cost. As of December 31, 2005, 9.1 million shares of common stock have been purchased under the share repurchase program for $429 million. During 2005 and 2004, 6.8 million shares, and 2.3 million shares, respectively, of common stock were purchased under the share repurchase program for $354 million and $75 million, respectively.

Other Share Repurchases. During both the first quarter of 2005 and the fourth quarter of 2004, Exelon repurchased 0.2 million shares of common stock from a retired executive for $8 million and $7 million, respectively. These shares are held as treasury shares and recorded at cost.

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

Stock-Based Compensation Plans

Exelon maintains Long-Term Incentive Plans (LTIPs) for certain full-time salaried employees. The types of long-term incentive awards that have been granted under the LTIPs are non-qualified options to purchase shares of Exelon's common stock and common stock awards. At December 31, 2005, there were options for approximately 27,909,780 shares remaining for issuance under the LTIPs.

The exercise price of the stock options is equal to the fair market value of the underlying stock on the date of option grant. Options granted under the LTIPs become exercisable upon attainment of a target share value and/or specified vesting date. All options expire 10 years from the date of grant. The vesting period of options outstanding as of December 31, 2005 generally ranged from 3 years to 4 years.

Information with respect to the LTIPs at December 31, 2005 and changes for the three years then ended, is as follows:

	Shares 2005	Weighted Average Exercise Price (per share) 2005	Shares 2004	Weighted Average Exercise Price (per share) 2004	Shares 2003	Weighted Average Exercise Price (per share) 2003
Balance at January 1	25,205,285	$26.78	28,307,386	$24.51	31,773,980	$22.90
Options granted/assumed	5,298,750	42.89	6,994,288	32.57	6,346,400	24.85
Options exercised	(8,352,772)	25.08	(9,373,662)	24.20	(9,017,390)	19.03
Options canceled	(476,993)	33.23	(722,727)	27.34	(795,604)	25.09
Balance at December 31	21,674,270	$31.23	25,205,285	$26.78	28,307,386	$24.51
Exercisable at December 31	9,673,986	$26.03	13,097,192	$24.88	18,032,696	$24.33
Weighted average fair value of options granted during year		$ 6.33		$ 4.79		$ 5.52

The fair value of each option is estimated on the date of grant using the Black-Scholes option-pricing model with the following weighted average assumptions used for grants in 2005, 2004 and 2003, respectively:

	2005	2004	2003
Dividend yield	3.6%	3.3%	3.3%
Expected volatility	18.1%	19.7%	30.5%
Risk-free interest rate	3.83%	3.25%	3.0%
Expected life (years)	6.25	5.0	5.0

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

At December 31, 2005, the options outstanding, based on ranges of exercise prices, were as follows:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number Outstanding	Weighted Average Remaining Contractual Life (years)	Weighted Average Exercise Price	Number Exercisable	Weighted Average Exercise Price
$9.37-$14.06	225,747	1.4	$11.82	225,747	$11.82
$14.06-$18.74	313,946	3.8	18.28	313,946	18.28
$18.74-$23.43	1,553,824	3.3	19.58	1,553,824	19.58
$23.43-$28.11	5,683,692	6.4	24.40	3,339,492	24.09
$28.11-$32.80	8,109,936	6.9	31.68	3,647,752	30.63
$32.80-$37.48	632,875	5.7	33.85	514,075	33.91
$37.48-$46.85	5,154,250	9.0	42.89	79,150	42.85
Total	21,674,270	6.9	$31.23	9,673,986	$26.03

Exelon common share awards of 871,410, 1,813,874 and 901,958 shares were granted under Exelon's LTIPs and board compensation plans during 2005, 2004 and 2003, respectively. Compensation costs related to these awards are accrued and expensed over the vesting period, typically up to 5 years from the grant date. Exelon recognized stock-based compensation expense of $57 million, $65 million and $31 million during 2005, 2004 and 2003, respectively. At December 31, 2005 and 2004, Exelon had a liability of $100 million and $81 million, respectively, related to outstanding awards not yet settled through cash payments or share issuances.

Exelon also has an ESPP. The purpose of the ESPP is to provide employees of Exelon and its subsidiary companies the right to purchase shares of Exelon's common stock at below-market prices. A total of 5,357,745 shares of Exelon's common stock have been reserved for issuance under the ESPP. Employees' purchases are limited to no more than 155 shares per quarter and no more than $25,000 in fair market value in any plan year. Employees purchased 259,072, 309,492, and 418,652 shares of Exelon common stock under the ESPP in 2005, 2004 and 2003, respectively.

Undistributed Losses of Equity Method Investments

Exelon had undistributed losses of equity method investments of $107 million and $57 million at December 31, 2005 and 2004, respectively.

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

19. Earnings Per Share

Diluted earnings per share are calculated by dividing net income by the weighted average number of shares of common stock outstanding, including shares to be issued upon exercise of stock options outstanding under Exelon's stock option plans considered to be common stock equivalents. The following table sets forth the computation of basic and diluted earnings per share and shows the effect of these stock options on the weighted average number of shares outstanding used in calculating diluted earnings per share:

	2005	2004	2003
Income from continuing operations	$ 951	$1,870	$ 892
Gain (loss) from discontinued operations	14	(29)	(99)
Income before cumulative effect of changes in accounting principles	965	1,841	793
Cumulative effect of changes in accounting principles	(42)	23	112
Net income	$ 923	$1,864	$ 905
Average common shares outstanding—basic	669	661	651
Assumed exercise of stock options	7	8	6
Average common shares outstanding—diluted	676	669	657
Earnings per average common share—Basic:			
Income from continuing operations	$ 1.42	$ 2.83	$ 1.37
Income (loss) from discontinued operations	0.02	(0.04)	(0.15)
Income before cumulative effect of changes in accounting principles	1.44	2.79	1.22
Cumulative effect of changes in accounting principles	(0.06)	0.03	0.17
Net income	$ 1.38	$ 2.82	$ 1.39
Earnings per average common share—Diluted:			
Income from continuing operations	$ 1.40	$ 2.79	$ 1.36
Income (loss) from discontinued operations	0.02	(0.04)	(0.15)
Income before cumulative effect of changes in accounting principles	1.42	2.75	1.21
Cumulative effect of changes in accounting principles	(0.06)	0.03	0.17
Net income	$ 1.36	$ 2.78	$ 1.38

The number of stock options not included in the calculation of diluted common shares outstanding due to their antidilutive effect was approximately nine million for 2003. There were no stock options excluded for 2005 or 2004.

20. Commitments and Contingencies

Nuclear Insurance

The Price-Anderson Act limits the liability of nuclear reactor owners for claims that could arise from a single incident. As of December 31, 2005, the limit is $10.76 billion and is subject to change to account for the effects of inflation and changes in the number of licensed reactors. Through its subsidiaries, Exelon carries the maximum available commercial insurance of $300 million for each operating site and the remaining $10.46 billion is provided through mandatory participation in a financial protection pool. Under the Price-Anderson Act, all nuclear reactor licensees can be assessed a maximum charge per reactor per incident. The maximum assessment for all nuclear operators per reactor per incident (including a 5% surcharge) is $100.6 million, payable at no more than $15 million per reactor per incident per year. This assessment is subject to inflation and state premium taxes.

In addition, the U.S. Congress could impose revenue-raising measures on the nuclear industry to pay claims. The Price-Anderson Act was extended to December 31, 2025 under the Energy Act Policy.

Generation is a member of an industry mutual insurance company, Nuclear Electric Insurance Limited (NEIL), which provides property damage, decontamination and premature decommissioning insurance for each station for losses resulting from damage to its nuclear plants. In the event of an accident, insurance proceeds must first be used for reactor stabilization and site decontamination. If the decision is made to decommission the facility, a portion of the insurance proceeds will be allocated to a fund, which Generation is required by the NRC to maintain, to provide for decommissioning the facility. Generation is unable to predict the timing of the availability of insurance proceeds to Generation and the amount of such proceeds that would be available. Under the terms of the various insurance agreements, Generation could be assessed up to $176 million for losses incurred at any plant insured by the insurance companies. In the event that one or more acts of terrorism cause accidental property damage within a twelve-month period from the first accidental property damage under one or more policies for all insured plants, the maximum recovery for all losses by all insureds will be an aggregate of $3.2 billion plus such additional amounts as the insurer may recover for all such losses from reinsurance, indemnity and any other source, applicable to such losses. The $3.2 billion maximum recovery limit is not applicable, however, in the event of a "certified act of terrorism" as defined in the Terrorism Risk Insurance Act of 2002, as extended, as a result of government indemnity. Generally, a "certified act of terrorism" is defined in the Terrorism Risk Insurance Act to be any act, certified by the U.S. government, to be an act of terrorism committed on behalf of a foreign person or interest.

Additionally, NEIL provides replacement power cost insurance in the event of a major accidental outage at a nuclear station. The premium for this coverage is subject to assessment for adverse loss experience. Generation's maximum share of any assessment is $47 million per year. Recovery under this insurance for terrorist acts is subject to the $3.2 billion aggregate limit and secondary to the property insurance described above. This limit would also not apply in cases of certified acts of terrorism under the Terrorism Risk Insurance Act, as extended, as described above.

In addition, Generation participates in the American Nuclear Insurers Master Worker Program, which provides coverage for worker tort claims filed for bodily injury caused by a nuclear energy accident. This program was modified, effective January 1, 1998, to provide coverage to all workers whose "nuclear-related employment" began on or after the commencement date of reactor operations. Generation will not be liable for a retrospective assessment under this new policy; however, in the event losses incurred under the small number of policies in the old program exceed accumulated reserves, a maximum retroactive assessment of up to $50 million could apply.

For its insured losses, Exelon is self-insured to the extent that losses are within the policy deductible or exceed the amount of insurance maintained. Such losses could have a material adverse effect on Exelon's financial condition, results of operations and liquidity.

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

Energy Commitments

Generation's wholesale operations include the physical delivery and marketing of power obtained through its generation capacity, and long-, intermediate- and short-term contracts. Generation maintains a net positive supply of energy and capacity, through ownership of generation assets and purchase power and lease agreements, to protect it from the potential operational failure of one of its owned or contracted power generating units. Generation has also contracted for access to additional generation through bilateral long-term purchase power agreements (PPAs). These agreements are firm commitments related to power generation of specific generation plants and/or are dispatchable in nature. Generation enters into purchase power agreements with the objective of obtaining low-cost energy supply sources to meet its physical delivery obligations to its customers. Generation has also purchased firm transmission rights to ensure that it has reliable transmission capacity to physically move its power supplies to meet customer delivery needs. The primary intent and business objective for the use of its capital assets and contracts is to provide Generation with physical power supply to enable it to deliver energy to meet customer needs. Generation primarily uses financial contracts in its wholesale marketing activities for hedging purposes. Generation also uses financial contracts to manage the risk surrounding trading for profit activities.

Generation has entered into bilateral long-term contractual obligations for sales of energy to load-serving entities, including electric utilities, municipalities, electric cooperatives and retail load aggregators. Generation also enters into contractual obligations to deliver energy to wholesale market participants who primarily focus on the resale of energy products for delivery. Generation provides delivery of its energy to these customers through rights for firm transmission.

At December 31, 2005, Generation had long-term commitments, relating to the purchase from and sale to unaffiliated utilities and others of energy, capacity and transmission rights as indicated in the following tables:

	Net Capacity Purchases [(a)]	Power Only Sales	Power Only Purchases	Transmission Rights Purchases
2006	$ 616	$2,783	$1,508	$ 7
2007	527	947	491	3
2008	460	80	194	—
2009	434	18	194	—
2010	436	19	194	—
Thereafter	3,391	—	355	—
Total	$5,864	$3,847	$2,936	$ 10

(a) Net capacity purchases include tolling agreements that are accounted for as operating leases. Amounts presented in the commitments represent Generation's expected payments under these arrangements at December 31, 2005. Expected payments include certain capacity charges which are contingent on plant availability.

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

Fuel Purchase Obligations

In addition to Generation's energy commitments described above, Exelon has commitments to purchase fuel supplies for nuclear and fossil generation. As of December 31, 2005, these commitments were as follows:

		Expiration within			
	Total	2006	2007-2008	2009-2010	2011 and beyond
Fuel purchase agreements	$4,299	$754	$1,235	$933	$1,377

Commercial Commitments

Exelon's commercial commitments as of December 31, 2005, representing commitments potentially triggered by future events, were as follows:

	Total	Expiration within 2006	2007-2008	2009-2010	2011 and beyond
Letters of credit (non-debt) (a)	$ 116	$116	$—	$—	$ —
Letters of credit (long-term debt)—interest coverage (b)	15	15	—	—	—
Surety bonds (c)	296	132	66	—	98
Performance guarantees (d)	201	—	—	—	201
Energy marketing contract guarantees (e)	208	131	—	—	77
Nuclear insurance premiums (f)	1,710	—	—	—	1,710
Lease guarantees (g)	9	—	—	—	9
Midwest Generation Capacity Reservation Agreement guarantee (h)	25	4	8	8	5
Exelon New England guarantees (i)	14	—	—	—	14
Other	13	13	—	—	—
Total commercial commitments	$2,607	$411	$ 74	$ 8	$2,114

(a) Letters of credit (non-debt)—Exelon and certain of its subsidiaries maintain non-debt letters of credit to provide credit support for certain transactions as requested by third parties. As of December 31, 2005, Exelon had $116 million of outstanding letters of credit (non-debt) issued under its $1.5 billion credit agreements. Guarantees of $20 million have been issued to provide support for certain letters of credit as required by third parties.

(b) Letters of credit (long-term debt) interest coverage—Reflects the interest coverage portion of letters of credit supporting floating-rate pollution control bonds. The principal amount of the floating-rate pollution control bonds of $520 million is reflected in long-term debt in Exelon's Consolidated Balance Sheet.

(c) Surety bonds—Guarantees issued related to contract and commercial surety bonds, excluding bid bonds.

(d) Performance guarantees—Guarantees issued to ensure execution under specific contracts.

(e) Energy marketing contract guarantees—Guarantees issued to ensure performance under energy commodity contracts.

(f) Nuclear insurance premiums—Represent 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.

(g) Lease guarantees—Guarantees issued to ensure payments on building leases.

(h) Midwest Generation Capacity Reservation Agreement guarantee—In connection with ComEd's agreement with the City of Chicago (Chicago) entered into on February 20, 2003, Midwest Generation assumed from Chicago a Capacity Reservation Agreement that Chicago had entered into with Calumet Energy Team, LLC. ComEd has agreed to reimburse Chicago for any nonperformance by Midwest Generation under the Capacity Reservation Agreement. Under FIN 45, $3 million is included as a liability on Exelon's Consolidated Balance Sheets at December 31, 2005.

(i) Exelon New England guarantees—Mystic Development LLC (Mystic), a former affiliate of Exelon New England, has a long-term agreement through January 2020 with Distrigas of Massachusetts Corporation (Distrigas) for gas supply, primarily for the Boston Generating units. Under the agreement, gas purchase prices from Distrigas are indexed to the New England gas markets. Exelon New England has guaranteed Mystic's financial obligations to Distrigas under the long-term supply agreement. Exelon New England's guarantee to Distrigas remained in effect following the transfer of ownership interest in Boston Generating in May 2004. Under FIN 45, approximately $14 million is included as a liability within the Consolidated Balance Sheets of Exelon as of December 31, 2005 related to this guarantee. The terms of the guarantee do not limit the potential future payments that Exelon New England could be required to make under the guarantee. Other guarantees associated with Exelon New England total less than $1 million.

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

Environmental Issues

General. Exelon's 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, Exelon, through its subsidiaries, is generally liable for the costs of remediating environmental contamination of property now or formerly owned by Exelon and of property contaminated by hazardous substances generated by Exelon. Exelon's subsidiaries 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. ComEd and PECO have identified 42 and 27 sites, respectively, where former manufactured gas plant (MGP) activities have or may have resulted in actual site contamination. Of these 42 sites identified by ComEd, the Illinois Environmental Protection Agency has approved the clean up of six sites and of the 27 sites identified by PECO, the Pennsylvania Department of Environmental Protection has approved the cleanup of nine sites. Of the remaining sites identified by ComEd and PECO, 22 and 11 sites, respectively, are currently under some degree of active study and/or remediation. In addition, Exelon's subsidiaries 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.

As of December 31, 2005 and December 31, 2004, Exelon had accrued the following amounts for environmental liabilities:

	December 31, 2005	December 31, 2004
Total environmental investigation and remediation reserve	$128 [a]	$124 [b]
Portion of total related to MGP investigation and remediation	89	96

(a) Includes $89 million that has been recorded on a discounted basis, reflecting a discount rate of 4.0%. Estimate before the effects of discounting was $102 million, which reflects an inflation rate of 2.3%.

(b) Includes $96 million that has been recorded on a discounted basis, reflecting a discount rate of 4.3%. Estimate before the effects of discounting was $109 million, which reflects an inflation rate of 2.3%.

As of December 31, 2005, Exelon anticipates that payments related to the discounted environmental investigation and remediation costs, disclosed below on an undiscounted basis, will be:

2006	$ 12
2007	22
2008	18
2009	19
2010	10
Remaining years	21
Total payments	$102

Exelon cannot reasonably estimate whether it will incur other significant liabilities for additional investigation and remediation costs at these or additional sites identified by Exelon, environmental agencies or others, or whether such costs will be recoverable from third parties, including customers. However, pursuant to a PAPUC order, PECO is currently recovering through regulated gas rates costs associated with the remediation of the MGP sites. See Note 21—Supplemental Financial Information for further information regarding regulatory assets and liabilities.

Section 316(b) of the Clean Water Act. In July 2004, the EPA issued the final Phase II rule implementing Section 316(b) of the Clean Water Act. This rule establishes national requirements for reducing the adverse environmental impacts from the entrainment and impingement of aquatic organisms at existing power plants. The rule identifies particular standards of performance with respect to entrainment and impingement and requires each facility to monitor and validate this performance in future years. The requirements will be implemented through state-level National Pollutant Discharge Elimination System (NPDES) permit programs. All of Generation'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. Those facilities are Clinton, Cromby, Dresden, Eddystone, Fairless Hills, Handley, Mountain Creek, New Boston, Oyster Creek, Peach Bottom, Quad Cities and Salem. Generation is currently evaluating compliance options at its affected plants. At this time, Generation cannot estimate the effect that compliance with the Phase II rule requirements will have on the operation of its generating facilities and its future results of operations, financial condition and cash flows. There are many factors to be considered and evaluated to determine how Generation will comply with the Phase II rule requirements and the extent to which such compliance may result in financial and operational impacts. The considerations and evaluations include, but are not limited to obtaining clarifying interpretations of the requirements from state regulators, resolving outstanding litigation proceedings concerning the requirements, completing studies to establish biological baselines for each facility and performing environmental and economic cost benefit evaluations of the potential compliance alternatives in accordance with the requirements.

In a pre-draft permit dated May 13, 2005 and a draft permit issued on July 19, 2005, as part of the pending National Pollution Discharge Elimination System permit renewal process for Oyster Creek, the NJDEP preliminarily determined that closed-cycle cooling and environmental restoration are the only viable compliance options for Section 316(b) compliance at Oyster Creek. AmerGen has not made a determination regarding how it will demonstrate compliance with the Section 316(b) regulations, but believes that other compliance options under the final Phase II rule are viable and will be analyzed as part of the plant's comprehensive demonstration study.

In June 2001, the NJDEP issued a renewed NDPES permit for Salem, expiring in July 2006, allowing for the continued operation of Salem with its existing cooling water system. NJDEP advised PSEG in a letter dated July 12, 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. If application of the 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 share of the total cost of the retrofit and any resulting interim replacement power would likely be in excess of $500 million and could result in increased depreciation expense related to the retrofit investment.

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

Nuclear Generating Station Groundwater. On December 16, 2005, the Illinois Environmental Protection Agency issued a Violation Notice to Generation alleging that the company had violated state groundwater standards due to a discharge of liquid tritium from a line at the Braidwood Nuclear Generating Station. As of December 31, 2005, Exelon recorded a reserve of $7 million (pre-tax) for this matter, which Exelon deems adequate to cover the costs of remediation and potential related corrective measures. See Note 25—Subsequent Events for further details of this and similar matters.

Cotter Corporation. The 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 incurred by Cotter as a result of 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. Cotter is alleged to have disposed of approximately 39,000 tons of soils mixed with 8,700 tons of leached barium sulfate at the site. Cotter, along with three other companies identified by the EPA as potentially responsible parties (PRPs), has submitted a draft feasibility study addressing options for remediation of the site. The PRPs are also engaged in discussions with the State of Missouri and the EPA. The estimated costs of the anticipated remediation strategy for the site range up to $22 million. Once a remedy is selected, it is expected that the PRPs will agree on an allocation of responsibility for the costs. Generation has accrued what it believes to be an adequate amount to cover its anticipated share of the liability.

Voluntary Greenhouse Gas Emissions Reductions. Exelon announced on May 6, 2005 that it has established a voluntary goal to reduce its greenhouse gas (GHG) emissions by eight percent from 2001 levels by the end of 2008. The eight percent reduction goal represents a decrease of an estimated 1.3 million metric tons of GHG emissions. Exelon will incorporate recognition of GHG emissions and their potential cost into its business analyses as a means to promote internal investment in climate-reducing activities. Exelon made this pledge under the U.S. Environmental Protection Agency's Climate Leaders program, a voluntary industry-government partnership addressing climate change. Exelon believes that its planned greenhouse gas management efforts, including increased use of renewable energy, its current energy efficiency initiatives and its efforts in the areas of carbon sequestration, will allow it to achieve this goal. The anticipated cost of achieving the voluntary GHG emissions reduction goal will not have a material effect on Exelon's future results of operations, financial condition or cash flows.

Leases

Minimum future operating lease payments, including lease payments for vehicles, real estate, computers, rail cars and office equipment, as of December 31, 2005 were:

2006	$ 55
2007	55
2008	53
2009	48
2010	44
Remaining years	511
Total minimum future lease payments	$766[(a)]

(a) Excludes Generation's tolling agreements that are accounted for as operating leases and are reflected as net capacity purchases in the energy commitments table above.

Exelon's rental expense under operating leases totaled $68 million, $64 million and $57 million in 2005, 2004, and 2003, respectively. For information regarding Exelon's capital lease obligations, see Note 11—Long Term Debt.

Litigation

PJM Billing Dispute. In December 2004, Exelon filed a complaint against PJM and PPL Electric with the FERC alleging that PJM had overcharged Exelon from April 1998 through May 2003 as a result of a billing error. Specifically, the complaint alleges that PJM mistakenly identified PPL Electric's Elroy substation transformer as belonging to Exelon and that, as a consequence, during times of congestion, Exelon's bills for transmission congestion from PJM erroneously reflected energy that PPL Electric took from the Elroy substation and used to serve PPL Electric's load. The complaint requested the FERC, among other things, to direct PPL Electric to refund to PJM $39.1 million, plus interest of approximately $8 million, and for PJM to refund these same amounts to Exelon.

On September 14, 2005, Exelon and PPL filed a proposed settlement of this matter with the FERC. If the settlement is approved by the FERC, Exelon will receive a total of $40.5 million, plus interest, over the next four years from two funding sources: (a) $33 million from PPL Electric and (b) $7.5 million from PJM market participants. It is anticipated that approximately 75% and 25% of the proposed settlement will be received by Generation and PECO, respectively. Both charges will be collected and paid by PJM over a four-year period following FERC approval of the settlement with interest on the unpaid principal accruing over the collection and payment period. As Exelon is a market participant in PJM, if this settlement is approved by the FERC, the net amount of the settlement to be received by Exelon will be reduced by Exelon's portion of the $7.5 million described above.

Pending FERC approval of the proposed settlement, Exelon has not recorded any receivables associated with this matter.

Asbestos Personal Injury Claims. Like many other industrial companies, Generation is a defendant in personal injury actions related to asbestos exposure in certain facilities that are currently owned by Generation or were previously owned by ComEd and PECO. The vast majority of these asbestos-related bodily injury claims allege a variety of lung-related diseases based on alleged exposure to asbestos by former third-party contractors involved in the original construction or maintenance of the facilities. The construction of these facilities primarily occurred between 1950 and 1975. Generation does not have significant asbestos-related bodily injury claims occurring after 1980.

As part of the 2001 restructuring in which Generation purchased ComEd's and PECO's energy-producing facilities, Generation assumed all of ComEd's and PECO's current and future benefits and liabilities associated with these facilities. Based on the receipt of asbestos-related bodily injury claims during 2002, 2003 and 2004, where previously an insignificant number of claims were received and corresponding expenses were recorded, Generation engaged independent actuaries to determine if a reasonable estimate of future losses could be made based on historical claims data and other available information. Based on the currently available volume and diversity of historical claim and payment data, the actuaries determined that a reasonable estimate could be prepared and, accordingly, Generation engaged the actuaries to calculate an estimate of future losses. In the second quarter of 2005, based on the actuaries' analyses, management's review of current and expected losses and the view of counsel regarding the assumptions used in estimating the future losses, Exelon recorded an undiscounted $43 million pre-tax charge for its estimated portion of all estimated future asbestos-related personal injury claims estimated to be presented through 2030. This amount does not include estimated legal costs associated with handling these matters, which could be material. Exelon management determined that it was not reasonable to estimate future asbestos-related personal injury claims past 2030 based on only three years of historical claims data and the significant amount of judgment required to estimate this liability. In calculating future losses, management and the actuaries made various assumptions, including, but not limited to, the overall number of future claims estimated through the use of actuarial models, Exelon's estimated portion of future settlements and obligations, the distribution of exposure sites, the anticipated future mix of diseases that relate to asbestos exposure and the anticipated levels of awards made to plaintiffs. Exelon's recent history of successfully defending itself in court cases for asbestos-related bodily injury claims was qualitatively considered in determining this estimate.

The amounts recorded by Exelon for estimated future asbestos-related bodily injury claims are based upon known facts at the time the report was prepared. Projecting future events, such as the number of new claims to be filed each year and the average cost of disposing of claims, as well as the numerous uncertainties surrounding asbestos-related litigation in the United States, could cause the actual costs to be higher or lower than projected. While it is not possible to predict the ultimate outcome of the asbestos-related claims and settlements, management believes, after consultation with counsel, that resolution of these matters is not expected to have a material adverse effect on Exelon's results of operations and financial position. Management cautions, however, that these estimates for asbestos-related bodily injury cases and settlements are difficult to predict and may be influenced by many factors. Accordingly, these matters, if resolved in a manner different from the estimate, could have a material effect on Exelon's results of operations, financial position and cash flow.

The $43 million pre-tax charge was recorded as part of operating and maintenance expense on Exelon's Consolidated Statements of Income in 2005 and reduced net income by $27 million. At December 31, 2005 and 2004, Exelon had approximately $50 million and $10 million, respectively, reserved in total for asbestos-related bodily injury claims. As of December 31, 2005, approximately $9 million of this amount relates to 120 open claims presented to Generation, while the remaining $41 million of the reserve is for estimated future asbestos-related bodily injury claims anticipated to arise through 2030 based on actuarial assumptions and analysis. Exelon plans to obtain annual updates of the estimate of future losses. On a quarterly basis, Exelon monitors actual experience against the number of forecasted claims to be received and expected claim payments.

Oil Spill Liability Trust Fund Claim. In December 2004, the two Salem nuclear generation units were taken offline due to an oil spill from a tanker in the Delaware River near the facilities. The units, which draw water from the river for cooling purposes, were taken offline for approximately two weeks to avoid intake of the spilled oil, resulting in lost sales from the plant. Generation and PSEG have filed a joint claim for losses and damages with the Oil Spill Liability Trust Fund. As this matter represents a contingent gain, Generation has recorded no income resulting from this claim. However, Generation's management believes it is reasonably possible that damages and losses will be recovered and that Generation's portion of the estimated proceeds arising from the claim will be approximately $25 million. Exelon expects this matter to be resolved in 2006.

Real Estate Tax Appeals. PECO and Generation each have been challenging real estate taxes assessed on nuclear plants. PECO is involved in litigation in which it is contesting taxes assessed in 1997 under the Pennsylvania Public Utility Realty Tax Act of March 4, 1971, as amended (PURTA), and has appealed local real estate assessments for 1998 and 1999 on the Limerick Generating Station (Montgomery County, PA) (Limerick) and Peach Bottom Atomic Power Station (York County, PA) (Peach Bottom) plants. Generation is involved in real estate tax appeals for 2000 through 2004, also regarding the valuation of its Limerick and Peach Bottom plants, Quad Cities Station (Rock Island County, IL), Three Mile Island Nuclear Station (Dauphin County, PA) (TMI), Oyster Creek Station (Forked River, NJ) and LaSalle County Station (Seneca, IL). PECO and Generation have reached settlements with the taxing authorities over the Limerick real estate assessments for 1998 and 1999. Pursuant to the settlement agreement, all Limerick tax appeals were dismissed by the state court, PECO has agreed to an additional payment of approximately $3 million for the two PURTA years and Generation has agreed to make additional payments in lieu of taxes for years 2005 through 2008. As a result of the Limerick settlement, Exelon reduced its real estate tax reserve balance by $6 million in the first quarter of 2005. In addition, Generation reached a settlement with the taxing authorities over the TMI real estate assessment, which has been approved by the state court. As a result of the TMI settlement, Exelon reduced its real estate tax reserve balance by $6 million in the first quarter of 2005. Generation reached an agreement with the taxing authorities for all years under appeal for the Quad Cities station and the court approved the agreement on December 9, 2005. Generation also recently reached an agreement with the taxing authorities for all years under appeal for the Oyster Creek station and an order implementing Oyster Creek's property tax settlement was entered on December 16, 2005. In addition, on December 22, 2005, Generation reached an agreement for the 2005 tax year with the taxing authorities for LaSalle County Station, and is working towards court approval by the end of the first quarter of 2006.

Exelon believes its reserve balances for other exposures associated with real estate taxes as of December 31, 2005 and 2004 reflect the probable expected outcome of the litigation and appeals proceedings in accordance with SFAS No. 5. The ultimate outcome of such matters, however, could result in unfavorable or favorable adjustments to the consolidated financial statements of Exelon and such adjustments could be material.

ComEd Rate Case. As part of its current rate case, ComEd has requested recovery of amounts, which have previously been recorded as expense. Specifically, ComEd has requested recovery through rates of the $104 million (pre-tax) net loss on extinguishment of long-term debt as part of ComEd's 2004 Accelerated Liability Management Plan. Additionally, ComEd is seeking a new rider to recover environmental clean up costs that will occur after the transition period is over. These amounts are currently included in Exelon's liability for environmental investigation and remediation costs, which totaled $128 million as of December 31, 2005. As discussed in Note 4—Regulatory Issues, ComEd anticipates receiving a final order associated with the rate case during the third quarter of 2006. If the order affirms these requests, Exelon will recognize a one-time benefit to reverse these prior charges.

Reverse-Employment Discrimination Claim. On April 4, 2005, one employee of PECO and four employees of Generation commenced suit in the United States District Court for the Eastern District of Pennsylvania, alleging that they were subjected to a practice of reverse-employment discrimination which denied promotional opportunities to older white male employees, purportedly in violation of various Federal antidiscrimination statutes and the Pennsylvania Human Relations Act. The plaintiffs filed the action individually and on behalf of a putative class that includes all white males currently or previously employed with any Exelon companies in the United States who were at least 40 years old on April 4, 2003 and who either applied for or were eligible to apply for supervisory positions in March 2003 and thereafter, continuing to the present day, and were not selected for these positions. The defendants have filed an answer denying all liability and are proceeding with discovery pertaining to the class allegations and the named plaintiffs' individual claims. In December 2005, the Court ordered the case to be suspended until April 3, 2006 while the parties attempt to resolve this matter through non-binding mediation. As this case is in the early stages, Exelon cannot predict the outcome; however, Exelon does not expect this claim to have a material adverse effect on Exelon's financial condition, results of operations or cash flows.

General. Exelon is involved in various other litigation matters that are being defended and handled in the ordinary course of business. Exelon maintains accruals for such costs that are probable of being incurred and subject to reasonable estimation. The ultimate outcomes of such matters, as well as the matters discussed above, are uncertain and may have a material adverse effect on Exelon's financial condition, results of operations or cash flows.

Capital Commitments

Generation has a 72% interest in SCEP, which owns a peaking facility in Chicago. SCEP is obligated to make total equity distributions of $46 million through 2022 to the party, which is not affiliated with Exelon, that owns the remaining 28% interest. This amount reflects a return of that party's investment in SCEP. Generation has the right to purchase, generally at a premium, and the other party has the right to require Generation to purchase, generally at a discount, the 28% interest in SCEP. Additionally, Generation may be required to purchase the remaining 28% interest upon the occurrence of certain events, including Generation's failure to maintain an investment grade rating. The total long-term liability related to SCEP was $46 million and $49 million as of December 31, 2005 and 2004, respectively.

Fund Transfer Restrictions

Under applicable law, Exelon may borrow or receive any extension of credit or indemnity from its subsidiaries. Under the terms of Exelon's intercompany money pool agreement, Exelon can lend to, but not borrow from the money pool. Additionally, under applicable Federal law, ComEd, PECO and Generation can pay dividends only from retained, undistributed or current earnings. Under Illinois law, ComEd may not pay any dividend on its stock unless, among other things, "its earnings and earned surplus are sufficient to declare and pay same after provision is made for reasonable and proper reserves," or unless it has specific authorization from the ICC. At December 31, 2005 and 2004, Exelon had retained earnings of $3.2 billion and $3.4 billion, respectively, which included ComEd retained earnings (deficit) of $(81) million, consisting of $1,099 million of retained earnings appropriated for future dividends offset by unappropriated deficit of $(1,180) million, and $1,102 million (all which has been appropriated for future dividends at December 31, 2004), PECO retained earnings of $649 million and $607 million, and Generation undistributed earnings of $1,002 million and $761 million, respectively. At December 31, 2005 and 2004, Exelon's common equity to total capitalization ratio was 39% and 41%, respectively.

Jointly Owned Electric Utility Plant

On January 28, 2004, the NRC issued a letter requesting PSEG to conduct a review of its Salem facility, of which Generation owns 42.59%, to assess the workplace environment for raising and addressing safety issues. PSEG responded to the letter on February 28, 2004 and had independent assessments of the work environment at both facilities performed. Assessment results were provided to the NRC in May 2004. The assessments concluded that Salem was safe for continued operation, but also identified issues that need to be addressed. At an NRC public meeting on June 16, 2004, PSEG outlined its action plans to address these issues, which focus on safety conscious work environment, the corrective action program and work management. A letter documenting these plans and commitments was sent to the NRC on June 25, 2004. PSEG provided the NRC a report of its progress and the progress of its actions to resolve identified issues at public meetings in 2004 and 2005. PSEG continues to publish the metrics that demonstrate performance that commenced in the fourth quarter of 2004.

Income Taxes

Refund Claims. ComEd and PECO have entered into several agreements with a tax consultant related to the filing of refund claims with the IRS. ComEd and PECO previously made refundable prepayments to the tax consultants of $11 million and $5 million, respectively. The fees for these agreements are contingent upon a successful outcome of the claims and are based upon a percentage of the refunds recovered from the IRS, if any. The ultimate net cash outflows to ComEd and PECO related to these agreements will either be positive or neutral depending upon the outcome of the refund claim with the IRS. These potential tax benefits and associated fees could be material to the financial position, results of operations and cash flows of ComEd and PECO. A portion of ComEd's tax benefits, including any associated interest for periods prior to the PECO / Unicom Merger, would be recorded as a reduction of goodwill pursuant to a reallocation of the PECO / Unicom Merger purchase price. Exelon cannot predict the timing of the final resolution of these refund claims.

In 2004, the IRS granted preliminary approval for one of ComEd's refund claims and final approval was obtained in the first quarter of 2005. The refund and associated interest have been recorded in the consolidated financial statements. Approximately $14 million of tax and interest benefit received in the second quarter of 2005 has been reflected in the consolidated financial statements of which $12 million ($9 million after tax) was recorded to goodwill under the provisions of EITF Issue 93-7, "Uncertainties Related to Income Taxes in a Purchase Business Combination." As a result, ComEd recorded consulting expenses of $5 million (pre-tax) in 2004.

Based on negotiations with the IRS during the first half of 2005, PECO believed it would receive a tax refund related to one of its claims and recorded a $6 million (pre-tax) charge related to expected consulting charges through the second quarter of 2005. However, as the result of a recent unfavorable tax court decision involving another utility related to a similar type of refund claim, PECO no longer believes payment of the consulting fees is probable and reversed the $6 million (pre-tax) charge during the third quarter 2005. PECO is unable to predict the final impact of its future negotiations with the IRS on this matter.

Other Refund Claims. ComEd and PECO have filed several tax refund claims with Federal and state taxing authorities. ComEd and PECO are unable to estimate the ultimate outcome of these refund claims and will account for any amount received in the period the matters are settled with the Federal and state taxing authorities. To the extent ComEd is successful on any of its refund claims a portion of the tax and interest benefit will be recorded to goodwill under the provisions of EITF Issue 93-7, "Uncertainties Related to Income Taxes in a Purchase Business Combination."

Other. Exelon, through its ComEd subsidiary, has taken certain tax positions, which have been disclosed to the IRS to defer the tax gain on the 1999 sale of its fossil generating assets. See Note 12—Income Taxes for further information.

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

21. Supplemental Financial Information

Supplemental Income Statement Information

The following tables provide additional information about Exelon's Consolidated Statements of Income for the years ended December 31, 2005, 2004 and 2003.

	For the Years Ended December 31,		
	2005	2004	2003
Depreciation, amortization and accretion			
Property, plant and equipment [(a)]	$ 816	$ 835	$ 736
Regulatory assets	454	418	386
Nuclear fuel [(b)]	385	380	395
Asset retirement obligation accretion	243	210	160
Amortization of intangible assets	69	90	4
Total depreciation, amortization and accretion	$1,967	$1,933	$1,681

(a) Includes amortization of capitalized software costs.
(b) Included in fuel expense in Exelon's Consolidated Statements of Income.

	For the Years Ended December 31,		
	2005	2004	2003
Taxes other than income			
Utility [(a)]	$477	$439	$439
Real estate	121	146	65[(b)]
Payroll	103	95	81
Other	27	30	(15)[(c)]
Total taxes other than income	$728	$710	$570

(a) Municipal and state utility taxes are also recorded in revenues on Exelon's Consolidated Statements of Income.
(b) Includes the reduction of $74 million of property tax accruals during 2003.
(c) Includes a credit of $25 million in 2003 due to a favorable settlement of coal use tax issues at ComEd related to periods prior to the PECO / Unicom Merger.

	For the Years Ended December 31,		
	2005	2004	2003
Income (loss) in equity method investments			
Financing trusts of ComEd and PECO [(a)]	$ (30)	$ (44)	$—
AmerGen [(b)]	—	—	47
Sithe [(c)]	(1)	(11)	2
Synfuel	(104)	(84)	—
Affordable housing projects [(d)]	—	(9)	(10)
Communications joint ventures and other investments	1	(6)	(6)
Total income (loss) in equity method investments	$(134)	$(154)	$ 33

(a) Financing trusts were deconsolidated as of December 31, 2003.
(b) Prior to the acquisition of British Energy's 50% interest in December 2003.
(c) Includes losses incurred prior to Sithe's consolidation as of March 31, 2004 and losses from Sithe's investments in TEG and TEP prior to their sale in October 2004. See Note 3—Acquisitions and Dispositions for additional information.
(d) Prior to the sale of investments on October 15, 2004 and November 12, 2004.

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

	For the Years Ended December 31,		
	2005	2004	2003
Other, net			
Investment income	$ 9	$ 7	$ 14
Net loss on early extinguishment of debt	—	(130)	—
Gain on disposition of assets, net	12	111[d]	—
Decommissioning-related activities			
Decommissioning trust fund income [a]	135	194	79
Decommissioning trust fund income—AmerGen [a]	77	43	—
Other-than-temporary impairment of decommissioning trust funds	(22)[c]	(268)[e]	—
Regulatory offset to non-operating decommissioning-related activities [b]	(115)	66	(79)
Interest associated with Federal income taxes	—	—	(14)
Impairment of investment in Sithe	—	—	(255)
Impairment of investments and other assets	—	(14)	(40)
Net direct financing lease income	22	21	20
AFUDC, equity	7	4	9
Reserve for potential plant disallowance	—	—	12
Other	13	29	10
Total other, net	$ 138	$ 63	$(244)

(a) Includes investment income and net realized gains.
(b) Includes the elimination of non-operating decommissioning-related activity for those units that are subject to regulatory accounting, including the elimination of decommissioning trust fund income and other-than-temporary impairments for certain nuclear units. See Note 13—Nuclear Decommissioning and Spent Fuel Storage and Note 16—Fair Value of Financial Assets and Liabilities for more information regarding the regulatory accounting applied for certain nuclear units.
(c) Includes other-than-temporary impairments for 2005 totaling $20 million, $0 and $2 million on nuclear decommissioning trust funds for the former ComEd units, the former PECO units and AmerGen units, respectively.
(d) Includes $85 million gain on sale of Boston Generating. See Note 3—Acquisitions and Dispositions for additional information.
(e) Includes other-than-temporary impairments for 2004 totaling $255 million, $5 million and $8 million on nuclear decommissioning trust funds for the former ComEd units, the former PECO units and the AmerGen units, respectively.

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

Supplemental Cash Flow Information

As a result of adopting FIN 47 as of December 31, 2005, Exelon recorded an ARC, which was capitalized as an increase to the carrying amount of long-lived assets associated with liabilities recorded for conditional AROs. Of the total ARC, $29 million resulted in a non-cash investing activity. See Note 14—Conditional ARO for additional information on the adoption of FIN 47. In addition to this non-cash activity, the following table provides additional information about Exelon's Consolidated Statements of Cash Flows for the years ended December 31, 2005, 2004 and 2003.

	For the Years Ended December 31,		
	2005	2004	2003
Cash paid during the year			
Interest (net of amount capitalized)	$798	$888	$801
Income taxes (net of refunds)	378	205	728
Non-cash investing and financing activities			
Change in asset retirement cost	251	829	—
Consolidation of the voluntary employee beneficiary association trust	34	—	—
Resolution of certain tax matters and PECO / Unicom merger severance adjustment	23	14	—
Purchase accounting estimate adjustments	11	36	59
Sale of asset	4	—	—
Disposition of Boston Generating [(a)]	—	102	—
Note cancelled in conjunction with the acquisition of Sithe International from Sithe	—	92	—
Consolidation of Sithe pursuant to FIN 46-R	—	85	—
Non-cash issuance of common stock	—	26	16
Issuance of note payable to acquire synthetic fuel interests	—	22	238
Capital lease obligations		1	—
Note received in connection with the sale of Sithe to Reservoir	—	—	92
Note issued to Sithe in the Exelon New England acquisition	—	—	2

(a) See Note 3—Acquisitions and Dispositions for additional information regarding the disposition of Boston Generating.

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

Supplemental Balance Sheet Information

The following tables provide additional information about assets recorded within Exelon's Consolidated Balance Sheets as of December 31, 2005 and 2004.

December 31, 2005	ComEd	PECO	Generation	Other [(a)]	Exelon
Investments					
Equity method investments:					
Direct financing leases	$—	$—	$ —	$507	$507
Financing trusts [(b)]	34	73	—	—	107
TEG and TEP [(c)]	—	—	90	—	90
Energy services and other ventures	—	2	15	—	17
Total equity method investments	34	75	105	507	721
Other investments:					
Employee benefit trusts and investments	41	20	15	16	92
Total investments	$ 75	$ 95	$120	$523	$813

(a) Other includes corporate operations, shared service entities, including BSC, Enterprises and investments in synthetic fuel-producing facilities.
(b) Includes investments in financing trusts which were not consolidated within the financial statements of Exelon at December 31, 2004 pursuant to the provisions of FIN 46-R. See Note 1—Significant Accounting Policies for further discussion of the effects of FIN 46-R.
(c) Generation acquired 49.5% interests in two facilities in Mexico on October 13, 2004. See Note 3—Acquisitions and Dispositions for further information on this transaction.

December 31, 2004	ComEd	PECO	Generation	Other [(a)]	Exelon
Investments					
Equity method investments:					
Direct financing leases	$—	$ —	$ —	$486	$486
Financing trusts [(b)]	52	87	—	—	139
TEG and TEP [(c)]	—	—	79	—	79
Energy services and other ventures	—	2	10	2	14
Total equity method investments	52	89	89	488	718
Other investments:					
Employee benefit trusts and investments	39	20	14	12	85
Energy services and other ventures	—	—	—	1	1
Total other investments	39	20	14	13	86
Total investments	$ 91	$109	$103	$501	$804

(a) Other includes corporate operations, shared service entities, including BSC, Enterprises and investments in synthetic fuel-producing facilities.
(b) Includes investments in financing trusts which were not consolidated within the financial statements of Exelon at December 31, 2004 pursuant to the provisions of FIN 46-R. See Note 1—Significant Accounting Policies for further discussion of the effects of FIN 46-R.

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

(c) Generation acquired 49.5% interests in two facilities in Mexico on October 13, 2004. See Note 3—Acquisitions and Dispositions for further information on this transaction.

Like-Kind Exchange Transaction. Prior to the PECO / Unicom Merger, 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 passive generating station leases with two separate entities unrelated to Exelon. The generating stations were leased back to such entities as part of the transaction. 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. Under the terms of the lease agreements, UII received a prepayment of $1.2 billion in the fourth quarter of 2000, which reduced the investment in the lease. The remaining payments are payable at the end of the thirty-year lease and there are no minimum scheduled lease payments to be received over the next five years. The components of the net investment in the direct financing leases were as follows:

	December 31,	
	2005	2004
Total minimum lease payments	$1,492	$1,492
Less: unearned income	985	1,006
Net investment in direct financing leases	$ 507	$ 486

	December 31,	
	2005	2004
Other deferred debits and other assets		
Intangible assets [(a)]	$177	$ 804
Long-term prepaid state income taxes [(b)]	192	201
Long-term emission allowances	99	82
Deferred revenue options	94	—
Chicago agreement [(c)]	55	59
Chicago arbitration settlement [(d)]	52	55
Unamortized debt expense	48	39
Other	107	178
Total other deferred debits and other assets	$824	$1,418

(a) See Note 8—Intangible Assets for further information.

(b) Long-term prepaid state income taxes relate to ComEd's overpayment of state income taxes. The overpayment will be applied towards future state income tax payments.

(c) On February 20, 2003, ComEd entered into separate agreements with Chicago and with Midwest Generation. Under the terms of the agreement with Chicago, ComEd will pay Chicago and other parties a total of $60 million over ten years and be relieved of a requirement, originally transferred to Midwest Generation upon the sale of ComEd's fossil stations in 1999, to build a 500-MW generation facility. These payments were deferred and are amortized ratably over the life of the franchise agreement with Chicago through 2020.

(d) On March 22, 1999, ComEd reached a settlement agreement with Chicago to end the arbitration proceeding between ComEd and Chicago regarding the January 1, 1992 franchise agreement and a supplement agreement. As part of the settlement agreement, ComEd paid $25 million each year from 1999 to 2002 to help ensure an adequate and reliable electric supply for Chicago. These payments were deferred and are amortized ratably over the life of the franchise agreement with Chicago through 2020.

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

The following table provides additional information about liabilities recorded within Exelon's Consolidated Balance Sheets as of December 31, 2005 and 2004.

	December 31, 2005	December 31, 2004
Accrued expenses		
Compensation-related accruals [a]	$ 377	$ 346
Taxes accrued	256	312
Interest accrued	258	252
Severance accrued	20	69
Other accrued expenses	94	118
Total accrued expenses	$1,005	$1,097

(a) Primarily includes accrued payroll, bonuses and other incentives, vacation and benefits.

The following table provides information regarding counterparty margin deposit accounts as of December 31, 2005 and 2004.

	December 31, 2005	December 31, 2004
Other current assets		
Counterparty collateral deposits paid	$285	$41
Other current liabilities		
Counterparty collateral deposits received	101	44

The following table provides additional information about accumulated other comprehensive income recorded (after tax) within Exelon's Consolidated Balance Sheets as of December 31, 2005 and 2004.

	December 31, 2005	December 31, 2004
Accumulated other comprehensive loss		
Minimum pension liability	$(1,362)	$(1,372)
Net unrealized loss on cash-flow hedges	(337)	(138)
Unrealized gain on marketable securities	75	61
Foreign currency translation adjustment	—	3
Total accumulated other comprehensive loss	$(1,624)	$(1,446)

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

The following tables provide information about the regulatory assets and liabilities of ComEd and PECO as of December 31, 2005 and 2004.

ComEd	December 31, 2005	December 31, 2004
Regulatory assets (liabilities)		
Nuclear decommissioning	$(1,435)	$(1,433)
Removal costs	(1,015)	(1,011)
Reacquired debt costs and interest-rate swap settlements	107	118
Conditional asset retirement obligations	91	—
Recoverable transition costs	43	87
Deferred income taxes	8	4
Other	31	31
Total regulatory assets (liabilities)	$(2,170)	$(2,204)

PECO	December 31, 2005	December 31, 2004
Regulatory assets (liabilities)		
Competitive transition charges	$3,532	$3,936
Deferred income taxes	781	747
Non-pension postretirement benefits	45	52
Reacquired debt costs	36	42
MGP regulatory asset	26	32
DOE facility decommissioning	13	19
Conditional asset retirement obligations	13	—
Nuclear decommissioning	(68)	(46)
Other	8	8
Long-term regulatory assets	4,386	4,790
Deferred energy costs (current asset)	39	25
Total regulatory assets (liabilities)	$4,425	$4,815

Nuclear decommissioning. These amounts represent future nuclear decommissioning costs that exceed (regulatory asset) or are less than (regulatory liability) the associated decommissioning trust fund assets. Exelon believes the trust fund assets, including prospective earnings thereon and any future collections from customers, will equal the associated future decommissioning costs at the time of decommissioning. See Note 13—Nuclear Decommissioning and Spent Fuel Storage for further information.

Removal costs. These amounts represent funds received from customers to cover the future removal of property, plant and equipment. See Note 6—Property, Plant and Equipment for further information.

Reacquired debt costs and interest-rate swap settlements. The reacquired debt costs represent premiums paid for the early extinguishment and refinancing of long-term debt, which is amortized over the life of the new debt issued to finance the debt redemption. Interest-rate swap settlements are deferred and amortized over the period that the related debt is outstanding.

Conditional asset retirement obligations. These costs represent future removal costs associated with retirement obligations which will be collected over the remaining lives of the underlying assets. See Note 14—Conditional ARO for further information.

Recoverable transition costs. These charges, related to amounts that would have been unrecoverable but for the recovery mechanism, such as the CTC allowed under the Illinois restructuring act, are amortized based on the expected return on equity of ComEd in any given year. ComEd expects to fully recover and amortize these charges by the end of 2006. See Note 4—Regulatory Issues for discussion of recoverable transition cost amortization.

Deferred income taxes. These costs represent the difference between the method by which the regulator allows for the recovery of income taxes and how income taxes would be recorded by unregulated entities. Regulatory assets and liabilities associated with deferred income taxes, recorded in compliance with SFAS No. 71 and SFAS No. 109, include the deferred tax effects associated principally with liberalized depreciation accounted for in accordance with the rate-making policies of the ICC and PAPUC, as well as the revenue impacts thereon, and assume continued recovery of these costs in future rates. See Note 12—Income Taxes for further information.

Competitive transition charges. These charges represent PECO's stranded costs that the PAPUC determined would be recoverable through regulated rates. These costs are related to the deregulation of the generation portion of the electric utility business in Pennsylvania. The CTC includes intangible transition property sold to PETT, an unconsolidated subsidiary of PECO, in connection with the securitization of PECO's stranded cost recovery. These charges are being amortized through December 31, 2010 with a return on the unamortized balance of 10.75%.

Non-pension postretirement benefits. These costs are the result of transitioning to SFAS No. 106 in 1993, which are recoverable in rates through 2012.

MGP regulatory asset. These costs represent estimated MGP-related environmental remediation costs at PECO which are recoverable through regulated gas rates.

DOE facility decommissioning. These costs represent PECO's share of recoverable decommissioning and decontamination costs of the DOE nuclear fuel enrichment facilities established by the National Energy Policy Act of 1992.

Deferred energy costs (current asset). These costs represent fuel costs recoverable under the purchase gas adjustment clause.

Recovery of regulatory assets. The regulatory assets related to deferred income taxes and non-pension post retirement benefits did not require a cash outlay of investor supplied funds; consequently, these costs are not earning a rate of return. Recovery of the regulatory assets for conditional asset retirement obligations, reacquired debt costs, recoverable transition costs, MGP remediation costs, DOE facility decommissioning and deferred energy costs is provided for through regulated revenue sources. Therefore, these costs are earning a rate of return.

22. Segment Information

Exelon has three operating segments: ComEd, PECO and Generation. Exelon evaluates the performance of its business segments based on net income. As a result of developments during the fourth quarter of 2005, Exelon has concluded that it can no longer aggregate ComEd and PECO as a single reportable segment. These developments include the approaching end of the regulatory transition period and rate freeze in Illinois, the opposition to rate increases expressed by the Attorney General of the State of Illinois, changes in the ComEd Board of Directors and the selection of executive officers of ComEd with no responsibilities outside of ComEd. As a result, ComEd and PECO are no longer reported as a combined Energy Delivery reportable segment. For more information regarding ComEd's regulatory issues, see ComEd—Retail Electric Services below and Note 4 of Exelon's Notes to the Consolidated Financial Statements. Additionally, Exelon sold or wound down substantially all components of Exelon Enterprises Company, LLC (Enterprises) in 2004 and 2003. As such, Exelon ceased reporting Enterprises as a segment as of January 1, 2005. Prior period presentation has been adjusted for comparative purposes.

ComEd's business consists of the purchase and regulated retail and wholesale sale of electricity and distribution and transmission services in northern Illinois, including the City of Chicago. PECO's business consists of the purchase and regulated retail sale of electricity and distribution and transmission services in southeastern Pennsylvania, including the City of Philadelphia, and the purchase and regulated retail sale of natural gas and distribution services in the Pennsylvania counties surrounding the City of Philadelphia. Generation consists principally of the electric generating facilities and wholesale energy marketing operations of Generation, the competitive retail sales business of Exelon Energy Company, Generation's interest in Sithe and certain other generation projects.

See Note 3—Acquisitions and Dispositions for information regarding dispositions within the Generation segment and Enterprises in 2005, 2004 and 2003. Also, see Note 2—Discontinued Operations for information regarding Exelon's discontinued operations.

Effective January 1, 2004, Enterprises' competitive retail sales business, Exelon Energy Company, was transferred to Generation. Segment information for 2003 included in the table below has been adjusted to reflect Exelon Energy Company as part of the Generation segment.

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

An analysis and reconciliation of Exelon's business segment information to the respective information in the consolidated financial statements are as follows:

	ComEd	PECO	Generation [a]	Other [b]	Intersegment Eliminations	Consolidated
Total revenues [c]:						
2005	$ 6,264	$ 4,910	$ 9,046	$ 694	$(5,557)	$15,357
2004	5,803	4,487	7,703	670	(4,530)	14,133
2003	5,814	4,388	8,586	792	(4,432)	15,148
Intersegment revenues:						
2005	$ 8	$ 8	$ 4,848	$ 693	$(5,557)	$ —
2004	18	9	3,841	669	(4,537)	—
2003	65	11	3,920	479	(4,475)	—
Depreciation and amortization:						
2005	$ 413	$ 566	$ 254	$ 101	$ —	$ 1,334
2004	410	518	286	81	—	1,295
2003	386	487	200	42	—	1,115
Operating expenses [c]:						
2005	$ 6,276	$ 3,861	$ 7,194	$ 859	$(5,557)	$12,633
2004	4,186	3,473	6,664	842	(4,531)	10,634
2003	4,247	3,332	8,689	904	(4,433)	12,739
Interest expense:						
2005	$ 295	$ 280	$ 128	$ 131	$ (5)	$ 829
2004	369	303	103	61	(8)	828
2003	423	324	88	47	(9)	873
Income taxes:						
2005	$ 363	$ 247	$ 709	$ (375)	$ —	$ 944
2004	457	249	401	(394)	—	713
2003	465	253	(176)	(153)	—	389
Income (loss) from continuing operations						
2005	$ (676)	$ 520	$ 1,109	$ (2)	$ —	$ 951
2004	676	455	657	82	—	1,870
2003	702	473	(238)	(45)	—	892
Income (loss) from discontinued operations						
2005	$ —	$ —	$ 19	$ (5)	$ —	$ 14
2004	—	—	(16)	(13)	—	(29)
2003	—	—	(21)	(78)	—	(99)
Cumulative effect of changes in accounting principles:						
2005	$ (9)	$ (3)	$ (30)	$ —	$ —	$ (42)
2004	—	—	32	(9)	—	23
2003	5	—	108	(1)	—	112
Net income (loss):						
2005	$ (685)	$ 517	$ 1,098	$ (7)	$ —	$ 923
2004	676	455	673	60	—	1,864
2003	707	473	(151)	(124)	—	905
Capital expenditures:						
2005	$ 776	$ 298	$ 1,067	$ 24	$ —	$ 2,165
2004	721	225	960	15	—	1,921
2003	712	250	953	39	—	1,954
Total assets:						
2005	$17,211	$10,018	$17,724	$(2,564)	$ —	$42,389
2004	17,441	10,087	16,438	(1,242)	—	42,724
2003	17,965	10,373	14,649	(1,088)	—	41,899

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

(a) Effective January 1, 2004, Enterprises' competitive retail sales business, Exelon Energy Company, was transferred to Generation. Segment information for 2003 included in the table above has been adjusted to reflect Exelon Energy Company as part of the Generation segment.
(b) Other includes corporate operations, shared service entities, including BSC, Enterprises and investments in synthetic fuel-producing facilities.
(c) Utility taxes of $247 million, $234 million and $233 million are included in revenues and expenses for 2005, 2004 and 2003, respectively, for ComEd. Utility taxes of $230 million, $205 million and $206 million are included in revenues and expenses for 2005, 2004 and 2003, respectively, for PECO.

23. Related Party Transactions

Effective December 31, 2003, ComEd Financing II, ComEd Financing III, ComEd Funding, ComEd Funding Trust, PETT, PECC and PECO Trust III were deconsolidated from the financial statements of Exelon in conjunction with the adoption of FIN 46-R. Effective July 1, 2003, PECO Trust IV was deconsolidated from the financial statements of PECO in conjunction with the adoption of FIN 46. Prior periods were not restated.

Exelon's financial statements reflect related-party transactions with its unconsolidated affiliates as presented in the tables below.

	For the Years Ended December 31,		
	2005	2004	2003
Operating revenues from affiliates			
ComEd Transitional Funding Trust	$ 3	$ 3	$—
PETT [(a)]	9	10	—
Interest expense to affiliates			
ComEd Transitional Funding Trust	66	85	—
ComEd Financing II	13	13	—
ComEd Financing III	13	13	—
PETT	212	235	—
PECO Trust III	6	6	—
PECO Trust IV	6	6	3
Equity in earnings (losses) of unconsolidated affiliates			
ComEd Funding LLC	(14)	(20)	—
ComEd Financing III	—	1	—
PETT	(16)	(25)	—

(a) PECO receives a monthly service fee from PETT based on a percentage of the outstanding balance of all series of transition bonds.

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

	December 31, 2005	December 31, 2004
Receivables from affiliates (current)		
ComEd Transitional Funding Trust	$ 14	$ 9
Investment in affiliates		
ComEd Transitional Funding LLC	18	36
ComEd Financing II	10	10
ComEd Financing III	6	6
PETT	63	77
PECO Energy Capital Corp	4	4
PECO Trust IV	6	6
Receivable from affiliates (noncurrent)		
ComEd Transitional Funding Trust	12	10
Payables to affiliates (current)		
ComEd Financing II	6	6
ComEd Financing III	4	4
PECO Trust III	1	1
Long-term debt to ComEd Transitional Funding Trust and other financing trusts (including due within one year)		
ComEd Transitional Funding Trust	987	1,341
ComEd Financing II	155	155
ComEd Financing III	206	206
PETT	2,975	3,456
PECO Trust III	81	81
PECO Trust IV	103	103

24. Quarterly Data (Unaudited)

The data shown below include all adjustments which Exelon considers necessary for a fair presentation of such amounts:

	Operating Revenues		Operating Income (Loss)		Income (Loss) Before the Cumulative Effect of Changes In Accounting Principles		Net Income (Loss)	
	2005	2004	2005	2004	2005	2004	2005	2004
Quarter ended:								
March 31	$3,561	$3,635	$ 931	$ 771	$ 521	$380	$ 521	$412
June 30 [(a)]	3,484	3,438	897	853	514	521	514	521
September 30	4,473	3,748	1,312	1,198	725	577	725	568
December 31 [(b)]	3,838	3,312	(416)	677	(795)	363	(837)	363

(a) During the second quarter of 2004, Enterprises sold its Chicago business of Thermal and recorded a gain of $45 million (before income taxes). The results of Thermal have been classified as discontinued operations within the Consolidated Statements of Income.

(b) Results of operations for the quarter ended December 31, 2005 included a $1.2 billion impairment of ComEd's goodwill.

	Average Basic Shares Outstanding (in millions)		Earnings (Losses) per Basic Share Before the Cumulative Effect of Changes in Accounting Principles		Net Income (Loss) per Basic Share	
	2005	2004	2005	2004	2005	2004
Quarter ended:						
March 31	666	659	$ 0.78	$0.58	$ 0.78	$0.63
June 30	670	661	0.77	0.79	0.77	0.79
September 30	670	661	1.08	0.87	1.08	0.86
December 31 [(a)]	668	664	(1.19)	0.55	(1.25)	0.55

(a) Results of operations for the quarter ended December 31, 2005 included a $1.2 billion impairment of ComEd's goodwill.

	Average Diluted Shares Outstanding (in millions)		Earnings (Losses) per Diluted Share Before the Cumulative Effect of Changes in Accounting Principles		Net Income (Loss) per Diluted Share	
	2005	2004	2005	2004	2005	2004
Quarter ended:						
March 31	675	665	$ 0.77	$0.56	$ 0.77	$0.62
June 30	677	667	0.76	0.78	0.76	0.78
September 30	677	669	1.07	0.86	1.07	0.85
December 31 [(a)]	668	672	(1.19)	0.54	(1.25)	0.54

(a) Results of operations for the quarter ended December 31, 2005 included a $1.2 billion impairment of ComEd's goodwill.

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

	2005				2004			
	Fourth Quarter	Third Quarter	Second Quarter	First Quarter	Fourth Quarter	Third Quarter	Second Quarter	First Quarter
High price	$56.00	$57.46	$52.01	$47.18	$44.90	$37.90	$34.89	$34.43
Low price	46.62	49.60	44.14	41.77	36.73	32.69	30.92	32.18
Close	53.14	53.44	51.33	45.89	44.07	36.69	33.29	34.43
Dividends	0.400	0.400	0.400	0.400	0.400	0.305	0.275	0.275

25. Subsequent Events

PECO's Capital Stock Tax and Franchise Tax (CS/FT). On February 1, 2006, PECO was notified that the Pennsylvania (PA) Board of Finance and Revenue (BF&R) approved, in a 6-0 decision, PECO's request for resettlement of its 2001 and 2002 CS/FT liability. Based on this approval, Exelon reduced liabilities associated with its previously estimated CS/FT liabilities for the years 2001 through 2004 by a total of $11 million (after-tax), which has been reflected in Exelon's Consolidated Statements of Income for the year ended December 31, 2005 and Consolidated Balance Sheets as of December 31, 2005.

The basis for computing the CS/FT includes a five-year rolling average of the legal entity's net income. PECO had appealed to the PA Department of Revenue regarding the inclusion of certain income included in the calculation of these taxes.

Nuclear Generating Station Groundwater. On December 16, 2005, the Illinois Environmental Protection Agency (Illinois EPA) issued a Violation Notice to Generation alleging that the company had violated state groundwater standards as a result of historical discharges of liquid tritium from a line at the Braidwood Nuclear Generating Station. In November 2005, Generation discovered that spills from the line in 1998 and 2000 have resulted in a tritium plume in groundwater that is both on and off the plant site. Levels of tritium in portions of the plume are in excess of the Illinois EPA groundwater standard. Levels in portions of the plume also exceed the Illinois EPA and Federal limits for drinking water. However, samples from drinking water wells on property adjacent to the plant have shown that, with one exception, tritium levels in these wells are below levels that naturally occur. The tritium level in one drinking water well is elevated above levels that naturally occur, but is significantly below the state and federal drinking water standards, and Generation believes that this level poses no threat to human health. Generation has suspended liquid tritium discharges into the affected pipeline, and is investigating the causes of the releases to ensure that necessary corrective actions are taken to prevent another occurrence. Generation has analyzed the various remediation options for the groundwater, and submitted an initial report to the Illinois EPA on February 2, 2006. The Illinois EPA will determine the required remediation and whether a civil penalty will be assessed against Generation. Generation has notified 14 potentially affected adjacent property owners that, upon sale of their property, it will reimburse them for any diminution in property value caused by the release, and has purchased the property of one adjacent owner. As of December 31, 2005, Exelon recorded a reserve of $7 million (pre-tax) for this matter, which Exelon deems adequate to cover the costs of remediation and potential related corrective measures.

Also, as a result of intensified monitoring and inspection efforts in 2006, Exelon detected a small underground tritium leak at the Dresden Generating Station and tritium concentrations in standing water within concrete vaults at the Byron Generating Station. Neither of these discharges occurred outside the property lines of the plant, nor does Exelon believe either of these matters poses health or safety threats to employees or to the public. In response to the detection of tritium in water samples taken at the aforementioned nuclear generating stations, Exelon has launched an initiative across its ten-station nuclear fleet to systematically assess systems that handle tritium and take the necessary actions to minimize the risk of inadvertent discharge of tritium to the environment. The assessments will take place in 2006 and will cover pipes, pumps, valves, tanks and other pieces of equipment that carry tritiated water in and around the plants. At this time, Exelon cannot estimate the costs that may be incurred in connection with tritium assessment initiatives or possible remediation efforts of the Dresden and Byron matters.

Generation Credit Facilities Agreement. On February 10 through 13, 2006, Generation entered into separate additional credit facilities with aggregate bank commitments of $875 million, which may be drawn down in the form of loans and/or letters of credit. The additional credit facilities are each for a term of 364 days and contain the same terms as the revolving credit facilities described in Note 10—Notes Payable and Short-Term Debt. The credit facilities will be used primarily to meet short-term funding requirements and to issue letters of credit.

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