UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, DC 20549
FORM 8-K

CURRENT REPORT

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

February 21, 2003
(Date of earliest
event reported)

Commission File Number	Name of Registrant; State of Incorporation; Address of Principal Executive Offices; and Telephone Number	IRS Employer Identification Number
1-16169	EXELON CORPORATION (a Pennsylvania corporation) 10 South Dearborn Street - 37th Floor P.O. Box 805379 Chicago, Illinois 60680-5379 (312) 394-7398	23-2990190

Item 5. Other Events

The purpose of the Current Report is to file certain financial information regarding Exelon Corporation and Subsidiary Companies. Such financial information is set forth in the exhibits to this Current Report.

Item 7. Financial Statements and Exhibits

(c) Exhibits.

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SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

EXELON CORPORATION

/S/ Robert S. Shapard

Robert S. Shapard
Executive Vice President and Chief Financial Officer

February 21, 2003

Exhibit 23
Consent of the Independent Accountants

CONSENT OF INDEPENDENT ACCOUNTANTS

We hereby consent to the incorporation by reference in the Registration Statements on Form S-3 (File Nos. 333-57640 and 333-84446), on Form S-4 (File No. 333-37082) and on Form S-8 (File Nos. 333-61390 and 333-49780) of Exelon Corporation and Subsidiary Companies of our report dated January 29, 2003, except for Note 23 for which the date is February 20, 2003, relating to the financial statements, which appears in this Current Report on Form 8-K dated February 21, 2003.

PricewaterhouseCoopers LLP
February 21, 2003

Exhibit 99-1
Exelon Corporation and Subsidiary Companies Selected Financial Data

Summary of Earnings and Financial Condition

Exelon Corporation and Subsidiary Companies

in millions, except for per share data	2002	2001	2000 (a)	1999	1998
	For the Years Ended December 31,				
Statement of Income Data:					
Operating Revenues	$ 14,955	$ 14,918	$ 7,499	$ 5,478	$ 5,325
Operating Income	3,299	3,362	1,527	1,373	1,268
Income before Cumulative Effect of Changes in Accounting Principles	1,670	1,416	562	570	500
Cumulative Effect of Changes in Accounting Principles (net of income taxes)	(230)	12	24	--	--
Net Income	$ 1,440	$ 1,428	$ 586	$ 570	$ 500
Earnings per Common Share (Diluted):					
Income Before Cumulative Effect of Changes in Accounting Principles	$ 5.15	$ 4.39	$ 2.75	$ 2.89	$ 2.23
Cumulative Effect of Changes in Accounting Principles (net of income taxes)	(0.71)	0.04	0.12	--	--
Net Income	$ 4.44	$ 4.43	$ 2.87	$ 2.89	$ 2.23
Dividends per Common Share	$ 1.76	$ 1.82	$ 0.91	$ 1.00	$ 1.00
Average Shares of Common Stock Outstanding - Diluted	325	322	204	197	224

	2002	2001	2000 (a)	1999	1998
	December 31,				
Balance Sheet Data:					
Current Assets	$ 4,118	$ 3,735	$ 4,151	$ 1,221	$ 582
Property, Plant and Equipment, net	17,134	13,791	12,936	5,004	4,804
Deferred Debits and Other Assets	16,226	17,218	17,699	6,862	6,662
Total Assets	$ 37,478	$ 34,744	$ 34,786	$ 13,087	$ 12,048
Current Liabilities	$ 5,974	$ 4,370	$ 4,993	$ 1,286	$ 1,735
Long-Term Debt	13,127	12,879	12,958	5,969	2,920
Deferred Credits and Other Liabilities	9,963	8,749	8,959	3,726	3,756
Minority Interest	77	31	31	12	--
Preferred Securities of Subsidiaries	595	613	630	321	579
Shareholders' Equity	7,742	8,102	7,215	1,773	3,058
Total Liabilities and Shareholders' Equity	$ 37,478	$ 34,744	$ 34,786	$ 13,087	$ 12,048

(a) Reflects the effects of the Unicom Merger (October 20, 2000).

Exhibit 99-2

Exelon Corporation and Subisidiary Companies Market for Registrant's Common Equity and Related Stockholder Matters

Exelon Corporation's (Exelon) common stock is listed on the New York Stock Exchange. The following table sets forth the high and low sales prices, closing prices and dividends for Exelon's common stock for 2002 and 2001 on a per share basis.

				2002				2001
	Fourth Quarter	Third Quarter	Second Quarter	First Quarter	Fourth Quarter	Third Quarter	Second Quarter	First Quarter
High Price	$ 53.06	$ 52.83	$ 56.99	$ 53.88	$ 48.69	$ 67.65	$ 70.26	$ 69.75
Low Price	42.38	37.85	50.10	45.90	39.65	38.75	62.10	53.60
Close	52.77	47.50	52.30	52.97	47.88	44.60	64.12	65.60
Dividends	0.44	0.44	0.44	0.44	0.43	0.42	0.42	0.55 (a)

(a) The first quarter dividend in 2001 was a pro rata dividend. Unicom and PECO each paid their shareholders pro rata, per diem dividends from their last regular dividend dates through October 19, 2000. The first quarter covered the 119-day period from the date of the Merger, through the February 15, 2001 record date.

Exelon had 180,059 shareholders of common stock of record as of January 31, 2003.

Exhibit 99-3
Exelon Corporation and Subsidiary Companies Management's Discussion and Analysis of Financial Condition and Results of Operations

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

(Dollars in millions, unless otherwise noted)

General Business

On October 20, 2000, Exelon Corporation (Exelon or we) became the parent corporation for PECO Energy Company (PECO) and Commonwealth Edison Company (ComEd) as a result of a merger among PECO, Unicom Corporation (Unicom), the former parent company of ComEd, and Exelon (Merger). The Merger was accounted for using the purchase method of accounting with PECO as the acquiring company. Accordingly, our results of operations for 2000 consist of PECO's results of operations for 2000 and Unicom's results of operations after October 20, 2000.

During January 2001, we undertook a restructuring to separate our generation and other competitive businesses from our regulated energy delivery business at ComEd and PECO. As part of the restructuring, the generation-related operations and assets and liabilities of ComEd were transferred to Exelon Generation Company, LLC (Generation). Also, as part of the restructuring, the non-regulated operations and related assets and liabilities of PECO, representing PECO's generation and enterprises business segments, were transferred to Generation and Exelon Enterprises Company, LLC (Enterprises), respectively. Additionally, certain operations and assets and liabilities of ComEd and PECO were transferred to Exelon Business Services Company (BSC). BSC provides Exelon and its subsidiaries financial, human resource, legal, information technology, supply management and corporate governance services.

Exelon, a registered public utility holding company, through its subsidiaries, now operates in three business segments:

- Energy Delivery, whose businesses include the regulated sale of electricity and distribution and transmission services by ComEd in northern Illinois and PECO in southeastern Pennsylvania and the sale of natural gas and distribution services by PECO in the Pennsylvania counties surrounding the City of Philadelphia.
- Generation, consisting of the owned and contracted for electric generating facilities, energy marketing operations, and equity interests in Sithe Energies, Inc. (Sithe) and AmerGen Energy Company, LLC (AmerGen).
- Enterprises, consisting of competitive retail energy sales, energy and infrastructure services, communications and other investments (weighted towards the communications, energy services and retail services industries).

See Note 20 of the Notes to Consolidated Financial Statements for further segment information.

Goals and Strategies

Our vision is to build exceptional value - by becoming the best and most consistently profitable electricity and gas company in the United States. To implement our vision, we must

Live up to our commitments

- Keep the lights on.
- Perform safely - especially in nuclear operations.
- Constantly improve our environmental performance.
- Act honorably and treat everyone with respect, decency and integrity.
- Continue building a high performance culture that reflects the diversity of our communities.
- Report our results, opportunities and problems honestly and reliably.

Perform at world-class levels

- Relentlessly pursue greater productivity, quality and innovation.
- Understand the relationships among our businesses and optimize the whole.
- Promote and implement policies that build effective markets.
- Adapt rapidly to changing markets, politics, economics and technology to meet our customers' needs.
- Maximize the earnings and cash flow from our assets and businesses and sell those that do not meet our goals.

Invest in our consolidating industry

- Develop strategies based on learning from past successes and failures.
- Implement systems and best practices that can be applied to future acquisitions.
- Prioritize acquisition opportunities based on synergies from scale, scope, generation and delivery integration, and our ability to profitably satisfy provider of last resort (POLR) and other regulatory obligations.
- Make acquisitions that will best employ our limited investment resources to produce the most consistent cash flow and earnings accretion.
- Return earnings to shareholders when higher returns are not available from acquisition opportunities.

The first component of our strategy is to "live up to our commitments." As such, we will continue to make investments in our businesses to provide reliable services at fair prices. The second component of our vision is to "perform at world class levels," which includes our plan to develop a more fundamental and durable productivity improvement program to expand on 2002's Cost Management Initiative. Our process, The Exelon Way, is designed to create value and strengthen our competitive position by improving processes, productivity and cash flow. Our third major corporate goal is to "invest in our consolidating industry." To further our strategy, each of the business segments has formulated its own plans to achieve our corporate goals.

Energy Delivery. Energy Delivery focuses on providing reliable and affordable services to customers. ComEd and PECO continue to make improvements to their delivery systems to minimize the frequency and duration of service interruptions, while working more efficiently to lower their costs. We believe that ComEd and PECO will continue to provide a significant and steady source of earnings and cash flows over the next several years.

Generation. Generation is focused on providing low cost and reliable power through a generation portfolio with fuel and dispatch diversity. Generation's direction is to continue to increase fleet output and to improve fleet efficiency while sustaining operational safety. Power Team is the unit within Generation that manages the output of Generation's assets and energy sales to reduce the volatility of Generation's earnings and cash flows. We believe that Generation will provide a steady source of earnings through its low cost operations and will take advantage of higher wholesale prices when they can be realized.

Enterprises. Enterprises is focused on operating its investments with the goal of maximizing its earnings and cash flow. Enterprises is not currently contemplating any acquisitions. Enterprises expects to divest itself of businesses that are not consistent with our strategic direction. This does not necessarily mean that an immediate exit will be arranged, but rather we may retain businesses for a period of time if we believe that this course of action will strengthen their value.

Business Outlook and the Challenges in Managing Our Business

We face a number of challenges in achieving our vision and keeping our commitments to our customers and our investors; however, there are three principal areas on which we focus our attention. First, our financial performance is significantly affected by the availability and utilization of our generation facilities. As the largest U.S. nuclear generator, we face operational and regulatory risks that, if not managed diligently, could have significant adverse consequences. Second, our results of operations are directly affected by wholesale energy prices. Energy prices are driven by demand factors such as weather and economic conditions in our service territories. They are also driven by supply factors and the regions where we operate currently have excess capacity. Over the last several years, wholesale prices of electricity have generally been low. The possibility of continued low wholesale prices, coupled with a continued economic recessionary trend, could adversely affect our business. Finally, our business may be significantly impacted by the end of ComEd's regulatory transition period in 2006. By existing law, after 2006, ComEd will not collect competitive transition charges (CTCs) from customers who elect to receive generation services from alternative energy suppliers including the ComEd Power Purchase Option (PPO). Additionally, the current bundled rate structure may be reset in a regulatory proceeding. It is difficult to predict the outcome of a potential regulatory proceeding to establish rates for 2007 and thereafter, nor is it possible to predict what changes may occur to the restructuring law in Illinois; however, we are undertaking various efforts to mitigate the 2007 challenge.

These and other challenges affecting our businesses are described below. There are several factors, such as weather, economic activity and regulatory actions that affect Energy Delivery, Generation and Enterprises in different ways. Also, there are several factors that affect our business as a whole, such as environmental compliance and the ability to access capital on a cost-effective basis.

Energy Delivery

We must comply with numerous regulatory requirements in managing our Energy Delivery business, which affect our costs and responsiveness to changing events and opportunities.

Our Energy Delivery business is subject to regulation at the state and Federal levels. ComEd is regulated by the Illinois Commerce Commission (ICC) and PECO is regulated by the Pennsylvania Public Utility Commission (PUC). These state commissions regulate the rates, terms and conditions of service; various business practices and transactions; financing; and transactions between the utilities and our affiliates. Both ComEd and PECO are also subject to regulation by the Federal Energy Regulatory Commission (FERC), which regulates their transmission rates, certain other aspects of their businesses and, for PECO, gas pipelines. The regulations adopted by these state and Federal agencies affect the manner in which we do business, our ability to undertake specified actions and the costs of our operations.

We are involved in a number of regulatory proceedings as a part of the process of establishing the terms and rates for Energy Delivery's services.

These regulatory proceedings typically involve multiple parties, including governmental bodies, consumer advocacy groups and various consumers of energy, who have differing concerns but who have the common objective of limiting rate increases. The proceedings also involve various contested issues of law and fact and have a bearing upon the recovery of Energy Delivery's costs through regulated rates. During the course of the proceedings, we look for opportunities to resolve contested issues in a manner that grant some certainty to all parties to the proceedings as to rates and energy costs.

- ComEd Delivery Services Rate Case

  ComEd is authorized to charge customers who purchase electricity from an alternative supplier for the use of its distribution system to deliver that electricity. These delivery service rates are set through proceedings before the ICC based upon, among other things, the operating costs associated with ComEd's distribution system and the capital investment that ComEd has made in its distribution system. In April 2002, the ICC issued an interim order that set delivery rates for ComEd's residential customers. The interim order was subject to an audit of test year (2000) expenditures, including capital expenditures. In October 2002, the ICC received the report on the audit of the test year expenditures by a consulting firm engaged by the ICC to perform the audit. The consulting firm recommended certain additional disallowances to test year expenditures and rate base levels. ComEd does not expect any change in delivery service rates to have a significant impact on results of operations in 2003. However, the estimated potential investment write-off, before income taxes, could be up to approximately $100 million if the ICC ultimately determines that all or some portion of ComEd's distribution plant is not recoverable through rates. In 2002, ComEd recorded a charge to earnings, before income taxes, of $12 million representing the estimated minimum probable exposure. ComEd is in negotiations with several parties to resolve the delivery service case.

We must maintain the availability and reliability of Energy Delivery's delivery systems to meet customer expectations.

Each year increases in both customers and the demand for energy requires expansion and reinforcement of delivery systems to increase capacity and maintain reliability. Failures of the equipment or facilities used in those delivery systems could potentially interrupt energy delivery services and related revenues, and increase repair expenses and capital expenditures. Such failures, including prolonged or repeated failures, also could affect customer satisfaction and may increase regulatory oversight and the level of our maintenance and capital expenditures. In addition, under Illinois law, ComEd can be required to pay damages to its customers in the event of extended outages affecting large numbers of its customers.

We must manage Energy Delivery's costs due to the rate and equity return limitations imposed on Energy Delivery's revenues.

Rate freezes and caps in effect at ComEd and PECO currently limit Energy Delivery's ability to recover increased expenses and the costs of investments in new transmission and distribution facilities. As a result, our future results of operations will depend on the ability of ComEd and PECO to deliver electricity and, in the case of PECO, natural gas, in a cost-efficient manner, and to realize cost savings to offset increased infrastructure investments and inflation.

- Rate limitations

  ComEd is subject to a legislatively mandated rate freeze on bundled retail rates that will remain effective until January 1, 2007. PECO is subject to agreed-upon rate reductions of $200 million, in aggregate, for the period 2002 through 2005 and 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 as a result of settlements previously reached with the PUC.

- Equity return limitation

  ComEd is subject to a legislatively mandated cap on its return on common equity through the end of 2006. The cap is based on a two-year average of the U.S. Treasury long-term rates (25 years and above) plus 8.5%, and is compared to a two-year average return on ComEd's common equity. The legislation requires customer refunds equal to one-half of any excess earnings above the cap. ComEd is allowed to include regulatory asset amortization in the calculation of earnings. ComEd has not triggered the earnings provision and currently does not expect to trigger the earnings sharing provision in the years 2003 through 2006.

Energy Delivery has and will lose energy customers to other generation service providers, although it continues to provide delivery services and may have an obligation to provide generation service to those customers.

- The revenues of our Energy Delivery business will vary because of customer choice of generation suppliers

  As a result of restructuring initiatives in Illinois and Pennsylvania, all of Energy Delivery's retail electric customers can choose to purchase their generation supply from alternative suppliers. If customers do not choose an alternative generation supplier or take service under ComEd's PPO, ComEd and PECO are each currently generally obligated to provide generation and delivery service to customers in their service territories at fixed rates, or in some instances, market-derived rates. In addition, customers who choose an alternative generation supplier may later return to ComEd or PECO, provided, however, that under Illinois law ComEd's obligation to provide generation may be eliminated over time if the ICC finds that competitive supply options are available to certain classes of customers. ComEd and PECO remain obligated to provide transmission and distribution service to all customers regardless of their generation supplier. To the extent that customers leave traditional bundled tariffs and select a different generation provider, Energy Delivery's revenues are likely to decline.

  At December 31, 2002, based on sales of energy, approximately 27% of ComEd's small commercial and industrial (C&I) load and 61% of its large C&I load were purchasing their generation service from an alternative generation supplier or had chosen ComEd's PPO, a market-based price for energy. There are currently no certified alternative suppliers for the residential market in ComEd's service territory. Also, at December 31, 2002, approximately 10% of PECO's small C&I load, 7% of its large C&I load and 21% of its residential load were purchasing their generation service from an alternative electric generation supplier.

PECO's Electric Restructuring Settlement established market share thresholds (MST) for residential and commercial customers such that if, on January 1, 2003, 50% of PECO's residential and commercial customers (by number of customers for residential and small commercial classes, and by load for large commercial classes) are not obtaining generation service from alternative generation suppliers, then non-shopping customers, up to the MSTs level, will be randomly assigned to alternative generation suppliers. The assigned customers have the right, at any time, to return to PECO or to switch to another supplier.

The number of customers choosing alternative generation suppliers depends in part on the prices being offered by those suppliers relative to the fixed prices that ComEd and PECO are authorized to charge by their state regulatory commissions. As a result of the right of customer choice of generation suppliers, we anticipate that our revenues and gross margins could vary.

Energy Delivery continues to serve as the provider of last resort for energy for all customers in its service territories.

ComEd and PECO are required to make available generation service to all retail customers in their service territories, including customers that have taken energy from an alternative generation supplier. ComEd and PECO customers can "switch," that is, they can choose an alternative generation supplier and then return to us and then go back to an alternative supplier, and so on, within limits. Because customers can switch, planning for Energy Delivery has a higher level of uncertainty than that traditionally experienced due to weather and the economy. In order to mitigate this risk with regard to our large commercial and industrial customers, on July 19, 2002, ComEd filed a request with the ICC to revise its POLR obligation in Illinois to be the back-up energy supplier to certain businesses. ComEd is seeking permission from the ICC to limit the availability by June 2006 of Rate 6L for 370 of its largest energy customers. These are commercial and industrial customers, including heavy industrial plants, large office buildings, government facilities and a variety of other businesses with demands of at least three megawatts (MWs). Our request affects a total of approximately 2,500 MWs. On November 14, 2002, the ICC allowed our request to go into effect as of June 2003. Energy Delivery has no obligation to purchase power reserves to cover the load served by others. Presently, we manage the POLR obligation through full requirements contracts with Generation, under which Generation supplies ComEd's and PECO's power requirements. Because of the ability of customers to switch generation suppliers, there is uncertainty regarding the amount of Energy Delivery load that Generation must prepare for. This uncertainty increases Generation's costs. As a result, and in connection with our July 2002 ICC request, we are discussing the POLR obligation issue with a number of parties including those who were parties to our rate request.

Energy Delivery's long-term power purchase agreements provide a partial hedge to its customers' demand.

Because the bundled rates Energy Delivery charges its customers are frozen or capped for several years, as mentioned previously in the "Rate limitations" section, its ability to recover increased costs with increases in rates charged to these customers is limited. Therefore, to effectively manage its obligation to provide power to meet its customers' demand, Energy Delivery has established power supply agreements with Generation that reduce exposure to the volatility of market prices through 2006. Market prices relative to Energy Delivery's bundled rates still influence switching behavior among retail customers.

Our business may be significantly impacted by the end of the ComEd regulatory transition period in 2006, and to a lesser extent, the end of the PECO regulatory transition period in 2010.

Illinois electric utilities are allowed to collect CTCs from customers who choose an alternative supplier of electric generation service or choose a utility's PPO. CTCs were intended to assist electric utilities, such as ComEd, in recovering stranded costs that might not otherwise be recoverable in a fully competitive market. The CTC charge represents the difference between the competitive price of delivered energy (the sum of generation service at competitive prices and the regulated price of energy delivery) and recoveries under historical bundled rates, reduced by a mitigation factor. The CTC charges are updated annually. Over time, to facilitate the transition to a competitive market, the mitigation factor increases, thereby reducing the CTC charge. Under current law, ComEd will no longer collect CTCs at the end of 2006.

In 2001, ComEd collected $110 million of CTC revenue, while in 2002, CTC revenue collected increased to $306 million due to the change in the competitive price of delivered electricity, primarily due to lower wholesale prices and more customers choosing alternative energy suppliers or the ComEd PPO. Based on increasing mitigation factors and our assumptions about the competitive price of delivered energy and customers' choice of electric suppliers, we estimate that CTC revenue will be approximately $250 to $300 million annually by 2006. In addition, the CTC is dependent on the ICC's determination of the market price of electricity. In a proceeding before the ICC, various market participants, including alternative providers and large customers, have proposed modifications to the method for determining the market price that, if accepted, could have the effect of reducing the CTC. Under the current restructuring statute, in 2007 this revenue will likely drop to zero. Through 2006, ComEd will continue to have a bundled service obligation, particularly to residential and small commercial customers. ComEd's current bundled service is generally provided under an all-inclusive rate that does not separately break out charges for energy generation service and energy delivery service, but charges a single set of prices. Much like the CTC collections, this revenue stream is authorized by the legislature through the transition period. After the transition ends in 2006, ComEd's bundled rates may be reset through a regulatory approval process, which may include traditional or innovative pricing, including performance-based incentives to ComEd.

During informal workshops sponsored by a member of the Illinois General Assembly, various market participants and interested parties made proposals which, if adopted, could have the effect of reducing the CTC.

In order to address post-transition uncertainty, we are constantly working with Illinois state and business community leadership to facilitate the development of a competitive electricity market while providing system reliability. This is particularly important as ComEd's costs to provide electricity to bundled residential and small commercial customers are capped by law at 110% of market. Transparent and liquid markets will help to minimize litigation over electricity prices and provide consumers assurance of equitable pricing. At the same time, we are attempting to establish a regulatory framework for the post-2006 timeframe. To offset CTC revenue loss after 2006, we are pursuing measures that would provide greater productivity, quality and innovation in our work practices across Exelon.

Our ability to make successful acquisition(s) and the recovery of wholesale power prices over the next several years will affect our ability to successfully manage this situation. Currently, it is difficult to predict the outcome of a potential regulatory proceeding to establish rates after 2006. We believe that no one factor will solve these challenges, but that a combination of the components currently being worked on, together with other things that we will do over the next four years, will address these challenges.

In Pennsylvania, as a mechanism for utilities to recover their allowed stranded costs, the Pennsylvania Electricity Generation Customer Choice and Competition Act (Competition Act) provides for the imposition and collection of non-bypassable CTCs on customers' bills. CTCs are assessed to and collected from all retail customers who have been assigned stranded cost responsibility and access the utilities' transmission and distribution systems. As the CTCs are based on access to the utility's transmission and distribution system, they will be assessed regardless of whether such customer purchases electricity from the utility or an alternative electric generation supplier. The Competition Act provides, however, that the utility's right to collect CTCs 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.

PECO has been authorized by the PUC to recover stranded costs of $5.3 billion ($4.6 billion of unamortized costs at December 31, 2002) over a twelve-year period ending December 31, 2010, with a return on the unamortized balance of 10.75%. PECO's recovery of stranded costs is 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. In 2002, revenue attributable to stranded cost recovery was $850 million and is scheduled to increase to $932 million by 2010, the final year of stranded cost recovery. Amortization of PECO's stranded cost recovery, which is a regulatory asset, is included in depreciation and amortization. The amortization expense for 2002 was $308 million and will increase to $879 million by 2010. Thus, PECO's results will be adversely affected over the remaining period ending December 31, 2010 by the reduction in the unamortized balance of stranded costs and therefore the return received on that unamortized balance.

Our ability to successfully manage the end of the transition period may affect our capital structure.

ComEd has approximately $4.9 billion of goodwill recorded at December 31, 2002. This goodwill was recognized and recorded in connection with the Merger. Under Generally Accepted Accounting Principles (GAAP), the goodwill will remain at its recorded amount unless it is determined to be impaired, which is based upon an analysis of ComEd's cash flows. If an impairment is determined at ComEd, the amount of the impaired goodwill will be written-off and expensed at ComEd. However, a goodwill impairment charge at ComEd may not affect Exelon's results of operations. Exelon's goodwill impairment test would include assessing the cash flows of the entire Energy Delivery business segment (a single Reporting Unit, which includes PECO, as defined under current accounting guidance), not just ComEd's cash flows. Presently, ComEd has sufficient cash flows to support the recorded amount of goodwill and thus, no impairment has been recorded. For a further discussion on this subject, see the Asset Impairment discussion in Critical Accounting Estimates. ComEd's cash flows include CTCs, which will cease at the end of 2006, unless there is a legislative or regulatory change and collections from traditional bundled customers at tariffed rates. Absent another source of revenues to replace the loss of the CTC revenue, all or a portion of the goodwill may become impaired. ComEd currently believes that there are a number of alternatives that could provide cash flows to support the goodwill. Under current regulations, a significant goodwill impairment may restrict ComEd's ability to pay dividends (see Credit Issues in Liquidity and Capital Resources). We are pursuing various solutions to address ComEd's ability to pay dividends if a significant goodwill impairment exists. However, based on Illinois legislation, goodwill impairments are excluded from determining whether or not the earnings cap amount has been met or exceeded (see Energy Delivery - Equity Return Limitations).

Weather affects electricity and gas usage and, consequently, Energy Delivery's results of operations.

Temperatures above normal levels in the summer tend to further increase summer cooling electricity demand and revenues, and temperatures below normal levels in the winter tend to further increase winter heating electricity and gas demand and revenues. Because of seasonal pricing differentials, coupled with higher consumption levels, we typically report higher revenues in the third quarter of our fiscal year. However, extreme summer conditions or storms may stress our transmission and distribution systems, resulting in increased maintenance costs and limiting our ability to bring power in to meet peak customer demand. These extreme conditions may have detrimental effects on our operations.

Economic conditions and activity in Energy Delivery's service territories directly affect the demand for electricity.

Higher levels of development and business activity generally increase the number of customers and their use of energy. Sales growth on an annual basis is expected to be 1.5% and 0.6% in ComEd's and PECO's service territories, respectively. In the long-term, output growth for electricity is expected to be 1.2% per year for Energy Delivery. However, there is continued economic uncertainty. Recessionary economic conditions, and the associated reduced economic activity, may adversely affect our results of operations.

Our business is affected by the restructuring of the energy industry.

The electric utility industry in the United States is in transition. As a result of both legislative initiatives as well as competitive pressures, the industry has been moving from a fully regulated industry, consisting primarily of vertically integrated companies that combine generation, transmission and distribution, to a partially restructured industry, consisting of competitive wholesale generation markets and continued regulation of transmission and distribution. These developments have been somewhat uneven across the states as a result of the reaction to the problems experienced in California in 2000 and the more recently publicized problems of some energy companies. Both Illinois and Pennsylvania have adopted restructuring legislation designed to foster competition in the retail sale of electricity. A large number of states have not changed their regulatory structures.

o Regional Transmission Organizations / Standard Market Design

To facilitate wholesale competition in the electric industry, FERC has required jurisdictional utilities to provide open access to their transmission systems. To foster the development of large regional wholesale markets, FERC issued Order 2000, encouraging the development of regional transmission organizations (RTOs) and the elimination of trade barriers between regions. FERC has also proposed rulemakings to mandate a standard market design (SMD) for the wholesale markets. Order 2000 and the proposed SMD rule contemplate that the jurisdictional transmission owners in a region will turn over operating authority over their transmission facilities to an RTO or other independent entity for the purpose of providing open transmission access. As a result, the independent entity will become the provider of the transmission service and the transmission owners will recover their revenue requirements through the independent entity. The transmission owners will remain responsible for maintaining and physically operating their transmission facilities. The SMD rulemaking proposal would also require RTOs to operate an organized bid-based wholesale market for those who wish to sell their generation through the market and to implement a financially-based system for dealing with congestion on transmission lines known as "locational marginal pricing" (LMP). FERC has also issued proposals to encourage RTO development, independent control of the transmission grid and expansion of the transmission grid by providing enhanced returns on equity for transmission assets.

PECO is a member of PJM Interconnection, LLC (PJM), an approved RTO operating in the Mid-Atlantic region. ComEd, along with other Midwestern utilities, joined PJM in a westward expansion of PJM. ComEd is expected to turn over control of its transmission assets to PJM later this year and recover its current transmission revenues through the PJM open-access transmission tariff.

FERC Order 2000 has not led to the rapid development of RTOs and FERC has not yet finalized its SMD proposal, due in part to substantial opposition by some state regulators and other governmental officials. We support both of these proposals but cannot predict whether they will be successful, what impact they may ultimately have on our transmission rates, revenues and operation of our transmission facilities, or whether they will ultimately lead to the development of large, successful regional wholesale markets. To the extent that ComEd and PECO have POLR obligations, and may at some point no longer have long-term supply contracts with Generation for their load, the ability of ComEd and PECO to cost effectively serve their POLR load obligation will depend on the development of such markets.

Effective management of capital projects is important to our business.

Energy Delivery's business is capital intensive and requires significant investments in energy transmission and distribution facilities, and in other internal infrastructure projects.

Energy Delivery continues to make significant capital expenditures to improve the reliability of its transmission and distribution systems in order to provide a high level of service to its customers. Energy Delivery expects that its capital expenditures will continue to exceed depreciation on its plant assets. Energy Delivery's base rate freeze and caps will generally preclude incremental rate recovery on any of these incremental investments prior to January 1, 2007 (see Energy Delivery - Rate and Equity Return Limitations above).

Generation

Our Generation business operates a fleet of generating assets and markets the output of a portfolio of supply, which includes 100% owned assets, co-owned facilities and purchased power. As discussed previously, Generation has entered into long-term power purchase agreements with ComEd and PECO. The majority of Generation's portfolio is used to provide power under these agreements. To the extent the portfolio is not needed to supply power to ComEd or PECO, their output is sold on the wholesale market. Generation's ability to grow is dependent upon its ability to cost-effectively meet ComEd's and PECO's load requirements, to manage its power portfolio and to effectively handle the changes in the wholesale power markets.

Our financial performance may be affected by liabilities arising from our ownership and operation of nuclear facilities.

The ownership and operation of nuclear facilities involve certain risks, including: mechanical or structural problems; inadequacy or lapses in maintenance protocols; the impairment of reactor operation and safety systems due to human error; the costs of storage, handling and disposal of nuclear material; and uncertainties with respect to the technological and financial aspects of decommissioning nuclear facilities at the end of their useful lives. The following are among the more significant of these risks:

- Operational risk

  Operations at any nuclear generation plant could degrade to the point where we would have to shut down the plant. If this were to happen, the process of identifying and correcting the causes of the operational downgrade to return the plant to operation could require significant time and expense, resulting in both lost revenue and increased fuel and purchased power expense to meet our supply commitments. For plants operated by us but not wholly owned by us, we could incur liabilities to the co-owners. We may choose to close a plant rather than incur substantial costs to restart the plant.

- Nuclear accident risk

  Although the safety record of nuclear reactors has been very good, accidents and other unforeseen problems have occurred both in the United States and elsewhere. The consequences of an accident can be severe and may include loss of life and property damage. Any resulting liability from a nuclear accident could exceed our insurance coverages and significantly affect our results of operations or financial position. See

Note 19 of Notes to the Consolidated Financial Statements for further discussion of nuclear insurance.

- Nuclear regulation

  The Nuclear Regulatory Commission (NRC) may modify, suspend or revoke licenses and impose civil penalties for failure to comply with the Atomic Energy Act, the regulations under it or the terms of the licenses of nuclear facilities. Changes in regulations by the NRC that require a substantial increase in capital expenditures or that result in increased operating or decommissioning costs could adversely affect our results of operations or financial condition. Events at nuclear plants owned by others, as well as those owned by us, may initiate such actions. Additional security requirements could also be imposed.

- Plant life extensions

  In 2001, Generation extended the estimated lives of certain nuclear stations. This change in estimate reflects the current and planned applications to the NRC to renew the operating licenses of Generation's nuclear stations. These applications for renewal, if approved by the NRC, will allow Generation to operate these plants for an additional 20 years longer than originally authorized. Nuclear station service life extensions are subject to NRC approval of an extension of existing NRC operating licenses, which are generally 40 years. We continue to fully believe that any such applications for renewal of operating licenses will be approved. However, if the NRC does not extend our operating licenses for our nuclear stations, our results of operations could be adversely affected by increased depreciation rates and accelerated future decommissioning payments.

Generation's financial performance is affected in large measure by the availability and use of its nuclear generation capacity.

- Nuclear capacity factors

  Generation capacity factors, particularly nuclear capacity factors, significantly affect our results of operations. Nuclear plant operations involve substantial fixed operating costs, but produce electricity at low marginal costs due to low variable fuel costs. Consequently, to be successful, Generation must consistently operate its nuclear generating facilities at high capacity factors. Generation's nuclear fleet performed at a 92.7% capacity factor (which represents the percentage of the total maximum energy that could be produced if facilities were operating full-time year round) in 2002 and is targeted to operate at a 94.2% capacity factor in 2003. In calculating capacity factors, Generation's nuclear fleet includes the AmerGen plants and excludes the Salem generation facility, which is operated by Public Service Enterprise Group Incorporated (PSE&G). Lower capacity factors would increase our operating costs and could require Generation to generate additional energy from its fossil or hydroelectric facilities or purchase additional energy in the spot or forward markets in order to satisfy its obligations to Energy Delivery and other committed third-party sales. These sources generally are at a higher cost than Generation otherwise would have incurred to generate energy from its nuclear stations.

- Refueling outage scheduling at nuclear plants affects availability and costs

  Outages at nuclear stations to replenish fuel require the station to be "turned off."

Refueling outages are planned to occur once every 18 to 24 months and currently average approximately 22 days in duration. We have significantly decreased the length of refueling outages in recent years. However, when refueling outages last longer than anticipated or we experience unplanned outages, we face lower margins due to higher energy replacement costs and/or lower energy sales. Each twenty-day outage, depending on the capacity of the station, will decrease the total nuclear annual capacity factor between 0.1% and 0.4%. The number of refueling outages, including AmerGen, will decrease to eight in 2003 from eleven in 2002. Maintenance and capital expenditures are expected to decrease by approximately $45 million and $10 million, respectively, in 2003 as compared to 2002 as a result of fewer nuclear refueling outages.

Generation is directly affected by wholesale energy prices.

Generation sells energy in the wholesale markets after meeting its contractual commitments to Energy Delivery and other parties. These sales expose Generation to the risks of rising and falling prices in those markets, and cash flows may vary accordingly. The amount of generation capacity that is exposed to the volatility of market prices depends inversely on the level of demand in the Energy Delivery companies.

The wholesale prices of electricity have generally been lower than historical levels over the last few years. A continued trend of low wholesale electricity prices could negatively affect our overall results of operations. Factors that affect wholesale energy prices include the overall demand for energy, fossil fuel costs and excess capacity within the industry.

- Demand for energy

  An increased demand for energy will normally cause energy prices to increase; however, if this increase in demand drives an incremental increase in supply, energy prices may be less affected. The demand for energy is directly affected by weather conditions and economic conditions in our service territories.

  - Weather conditions

    Generation's operations are affected by weather, which affects demand for electricity as well as operating conditions. We manage our business based upon normal weather assumptions. To the extent that weather is warmer in the summer or colder in the winter than we assumed, Generation may require greater resources to meet its contractual requirements to Energy Delivery. Extreme summer conditions or storms may affect the availability of generation capacity and transmission, limiting Generation's ability to send power to where it is sold. These conditions, which may not have been fully anticipated, may adversely affect us by causing Generation to seek additional capacity at a time when wholesale markets are tight or to seek to sell excess capacity at a time when those markets are weak. Generation does incorporate contingencies into its planning for extreme weather conditions, including reserving capacity to meet summer loads at levels representative of warmer than normal weather conditions.

  - Economic conditions

    Economic conditions and activity in Energy Delivery's service territories directly affect the demand for electricity and gas. Changes in economic conditions and activity in Energy Delivery's service territories and in other parts of the United States can affect the level of operations required in our generating facilities as well as the prevailing prices of electricity and gas in the wholesale markets in which we do business.

- Fossil fuel costs

  At any given time, the open market wholesale price of electricity is affected by the cost of supplying one more unit of electricity to the market at that time. Many times the next unit of electricity supplied would be supplied from generating stations fueled by fossil fuels, primarily natural gas. Consequently, the open market wholesale price of electricity may reflect the cost of gas plus the spark spread, the cost to convert gas to electricity. Therefore, changes in the cost of gas may impact the open market wholesale price of electricity.

- Excess capacity

  In addition to being affected by demand factors such as weather, the economy, and fossil fuel costs, energy prices are also impacted by the amount of supply available in a region. In the markets where we sell power, there has been a significant increase in the number of new power plants coming on-line which has driven down power prices over the last few years. In fact, an "excess supply" problem currently exists in many parts of the country. A key factor for Exelon's future earnings is the timing of a return to more normal levels in the supply-demand balance within the regions where we operate.

The scope and scale of our nuclear generation resources provide a cost advantage in meeting our contractual commitments and enable us to sell power in the wholesale markets.

The generation assets transferred to Generation by ComEd and PECO during the 2001 restructuring, the generating plants acquired in 2002 and Generation's investments in Sithe and AmerGen provide a critical mass of generation capacity and a leadership position in energy wholesale markets. Generation's resources, including AmerGen, include interest in 11 nuclear generation stations, consisting of 19 units, which generated 125,916 GWhs, or more than half of our total supply in 2002. As the largest generator of nuclear power in the United States, we can take advantage of our scale and scope to negotiate favorable terms for the materials and services that our business requires. Generation's nuclear plants benefit from stable fuel costs, minimal environmental impact from operations, and a safe operating history.

Our financial performance will be affected by our ability to effectively operate and integrate the assets of Sithe New England into our business and to market the output.

In November 2002, Generation acquired the generating assets of Sithe New England Holdings, LLC (Sithe New England). The Sithe New England assets, now known as the Exelon New England Holdings assets, include 2,421 MWs of gas-fired combined facilities under construction and several operating generating facilities, which together with the assets under construction total 4,066 MWs of capacity. The facilities under construction (Mystic 8, Mystic 9, and Fore River) are currently in the final stages of construction and testing. We anticipate commercial operation dates during the second quarter of 2003. These projects have experienced delays in construction and any further delays could adversely affect our results. See further discussion of the Sithe Boston Generation Project Debt in Liquidity and Capital Resources. With the continued low wholesale energy prices, we anticipate that the effects of the Sithe New England acquisition will be dilutive to earnings by approximately $125 million in 2003.

Power Team has not fully committed the output from these facilities into the New England markets. As such, the uncommitted capacity of the Exelon New England Holdings assets is subject to the fluctuations in market demand and market prices.

Substantially all of the natural gas requirements for Mystic 8 and Mystic 9 will be supplied through a twenty-year natural gas contract that became effective on December 1, 2002 with Distrigas of Massachusetts, LLC (Distrigas). The Distrigas facilities consist of a liquefied natural gas (LNG) import terminal located adjacent to the Mystic station. We are anticipating an additional pipeline gas supply arrangement to supplement LNG supplies to be in service by early 2005. In the interim, any disruption in LNG supplies to the Distrigas facilities could restrict the operating abilities of Mystic 8 and Mystic 9.

The interaction between our Energy Delivery and Generation businesses provide us a partial hedge.

The price of power purchased and sold in the open wholesale energy markets can vary significantly in response to market conditions. Both ComEd and PECO have entered into long-term agreements for the next several years with Generation to procure the power at fixed rates needed to meet the demand of their customers. The amounts provided to affiliates vary from month to month; however, delivery requirements are generally highest in the summer when wholesale power prices are also generally highest. Therefore, energy committed to serve ComEd and PECO customers is not exposed to the price uncertainty of the open wholesale energy market. Consequently, we have limited our earnings exposure to the volatility of the wholesale energy market to the energy generated beyond the ComEd and PECO requirements, as well as any other contracted longer term obligations. Generally, between 60% and 70% of our generation serves ComEd and PECO customers. We expect such levels to decrease to between 55% and 60% as a result of activating the acquired Sithe New England plants, which are currently under construction. One of the responsibilities of Power Team is to establish a hedging strategy, incorporating the load obligations of Energy Delivery, to minimize the contracted volatility of our earnings and cash flows, and to maximize the value of economic generation in excess of that needed to serve ComEd and PECO requirements.

Our financial performance depends on our ability to respond to competition in the energy industry.

As a result of industry restructuring, numerous generation companies created by the disaggregation of vertically integrated utilities have become active in the wholesale power generation business. In addition, independent power producers (IPP) have become prevalent in the wholesale power industry. In recent years, IPPs and the generation companies of disaggregated utilities have installed new generating capacity at a pace greater than the growth of electricity demand. As a result, the energy generation business is currently suffering from over capacity in certain parts of the country, which reduces wholesale energy prices. As discussed above, we are well positioned because Generation has entered into agreements for the next several years with ComEd and PECO to sell the power needed to meet the demand of their customers. These agreements provide a mechanism to enhance stability in our earnings and limit our exposure to the negative effects of wholesale markets.

The commencement of commercial operation of new generating facilities in the regional markets where we have facilities or contracts for power, such as the Midwest, Mid-Atlantic, Northeast and South (including certain sections of Texas), would likely decrease wholesale power market prices in those regions, which could have a negative effect on our business and results of operations.

Our financial performance may be affected by the marketing, trading and risk management activities of Power Team.

Generation's wholesale marketing unit, Power Team,

- uses our energy generation portfolio, transmission rights and its power marketing expertise to manage delivery of energy to wholesale customers, including Energy Delivery, under long-term and short-term contracts,
- participates in the wholesale energy market to hedge our open energy (power and fossil fuels) positions,
- manages commodity and counterparty credit risks through the use of documented risk and credit policies, and
- uses its energy market expertise to engage in trading activities for speculative purposes on a limited basis.

Power Team has substantial experience in energy markets, generation dispatch and the requirements for the physical delivery of power. Power Team may buy power to meet the energy demand of its customers, including Energy Delivery. 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 our generating capacity not used to meet our customer demand, in the wholesale energy market.

Power Team began proprietary trading activities in 2001, but this activity accounts for a small portion of Power Team's efforts. In 2002, proprietary trading activities resulted in an $18 million after-tax reduction in our earnings. We will continue proprietary trading activities but in a more limited capacity given the current lack of liquidity of power markets and reduced number of creditworthy counterparties.

Power Team has managed to avoid the recent managerial problems experienced in the energy trading industry through the strict adherence to prudent risk management practices. However, the recent failures of energy companies and their related energy trading practices over the last year have diminished the size and depth of the wholesale energy market. We cannot predict how this will affect our trading operations in the future.

We depend on counterparties fulfilling their obligations.

Our trading, marketing and contracting operations are exposed to the risk that counterparties, which owe us money or energy as a result of market transactions, will not perform their obligations. In order to evaluate the viability of our counterparties, we have implemented credit risk management procedures designed to mitigate the risks associated with these transactions. Energy supplied by third-party generators, including AmerGen and Sithe, under long-term agreements represents a significant portion of Generation's overall capacity. These third-party generators face operational risks such as those that Generation faces, and their ability to perform also depends on their financial condition. In the event the counterparties to these arrangements fail to perform, we might be forced to honor the underlying commitment at then-current market prices and incur additional losses, to the extent of amounts, if any, already paid to the counterparties. 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. These agreements 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.

See the Credit Risk section in the Quantitative and Qualitative Disclosures about Market Risk for further discussions on specific credit risk matters such as our potential counterparty exposures, including Dynegy Inc. (Dynegy).

Generation's business is also affected by the restructuring of the energy industry.

o Regional Transmission Organizations / Standard Market Design

Generation is dependent on wholesale energy markets and open transmission access and rights by which we deliver power to our wholesale customers, including ComEd and PECO. We use the wholesale regional energy markets to sell power that we do not need to satisfy our long-term contractual obligations, to meet long-term obligations not provided by our own resources, and to take advantage of price opportunities.

Wholesale spot markets have only been implemented in certain areas of the country and each market has unique features that may create trading barriers between the markets. Although FERC has proposed initiatives, including Order 2000 and the proposed SMD rule, to encourage the development of large regional, uniform markets and to eliminate trade barriers, these initiatives have not yet led to the development of such markets all across the country. PJM's market strongly resembles FERC's proposal, and both the New England Independent System Operator (NE-ISO) and the New York Independent System operator (NYISO) are implementing market reforms. We strongly encourage the development of standardized energy markets and support FERC's standardization efforts as being essential to wholesale competition in the energy industry and to Generation's ability to compete on a national basis and to meet its long-term contractual commitments efficiently.

Approximately 26% of our generation resources are located in the region encompassed by PJM. If the PJM market is expanded to the Midwest, 82% of our current assets will be located within the expanded market. The PJM market has been the most successful and liquid regional market and is largely consistent with the standard market design proposed by FERC. Our future results of operations may be impacted by the successful expansion of that market to the Midwest and the implementation of any market changes mandated by FERC.

- Provider of Last Resort

As noted, Energy Delivery has a POLR obligation that it has largely assigned to Generation through the full requirements contracts that it has with Generation. Currently both ComEd and PECO have entered into purchase power agreements (PPAs) with Generation to provide 100% of their respective energy requirements. ComEd's PPA with Generation is for 100% of its required load through 2004 at fixed prices, and in 2005 and 2006 it equals 100% of the output of ComEd's former nuclear plants, now owned by Generation at market based prices. PECO's PPA with Generation is a full load requirements contract through 2010. We intend to revise the PPA between ComEd and Generation to be a full requirements contract in 2005 and 2006. Additionally, the PPAs between Generation, ComEd and PECO may be extended beyond their current expiration dates. ComEd and PECO continue to work on resolution of the POLR issues with their respective state regulatory commissions and other market participants.

Effective management of capital projects is important to Generation's business.

Generation's business is capital intensive and requires significant investments in energy generation and in other internal infrastructure projects. As mentioned previously, as part of Generation's recent acquisition of the assets of Sithe New England, Generation is in the process of completing the construction of three high-efficiency generating facilities with projected capacity of 2,421 MWs of energy. The inability to effectively manage the capital projects, such as the Sithe New England facilities, could adversely affect our results from operations.

Enterprises

Enterprises' results of operations may be affected by its ability to strategically divest itself of certain businesses.

Enterprises may be unable to successfully implement its divestiture strategy of certain businesses for a number of reasons, including an inability to locate appropriate buyers or to negotiate acceptable terms for the transactions. In addition, the amounts that Enterprises may realize from a divestiture are subject to fluctuating market conditions that may contribute to pricing and other terms that are materially different than expected and could result in a loss on the sale. Timing of any divestitures may positively or negatively affect our results of operations as we expect certain businesses to be profitable going forward.

Enterprises may incur further impairments of its investments.

Enterprises wrote down $41 million of investments in 2002 when certain events occurred, such as competitors' technological advancement, accelerated distributions of public holdings at a loss, lack of achievability of financial results versus plan and limited access to capital markets. At

December 31, 2002, Enterprises held $128 million of investments. These types of events, or others, could continue to occur in 2003, which could result in additional impairment charges.

Enterprises' results of operations may be affected by its ability to manage its projects.

Enterprises consists of many businesses that utilize long-term fixed-price contracts. At the beginning of the contract, we estimate the total costs and profits of the contract; if the actual costs vary significantly form the estimates, our results of operations will be adversely impacted. Along with our ability to execute, results may be impacted by economic conditions, weather conditions and the regulatory environment.

Capital Markets / Financing Environment

In order to expand our operations and to meet the needs of our current and future customers, we invest in our businesses. Our ability to finance our businesses and other necessary expenditures is affected by the capital intensive nature of our operations and our current and future credit ratings. The capital markets also affect our decommissioning trust funds and benefit plan assets. Our financing needs will be dependent on our strategic direction of acquiring integrated utilities and generation facilities, and our ability to dispose of unprofitable businesses that do not advance our goals. Further discussions on our liquidity position can be found in the Liquidity and Capital Resources section.

Our ability to grow our business is affected by our ability to finance capital projects.

Our businesses require considerable capital resources. When necessary, we secure funds from external sources by issuing commercial paper and, as required, long-term debt securities. We actively manage our exposure to changes in interest rates through interest-rate swap transactions and our balance of fixed- and floating-rate instruments. We currently anticipate primarily using internally generated cash flows and short-term financing through commercial paper to fund our operations as well as long-term external financing sources to fund capital requirements as the needs and opportunities arise. Our ability to arrange debt financing, to refinance current maturities and early retirements of debt, and the costs of issuing new debt are dependent on:

- credit availability from banks and other financial institutions,
- maintenance of acceptable credit ratings (see Our Credit Ratings below),
- investor confidence in us,
- investor confidence in other regional wholesale power markets, o general economic and capital market conditions,
- the success of current projects, and o the perceived quality of new projects.

Our credit ratings influence our ability to raise capital.

Our businesses have investment grade ratings and have been successful in raising capital, which has been used to further our business initiatives. Also, from time to time, we enter into energy commodity and other contracts that require the maintenance of investment grade ratings. Failure to maintain investment grade ratings would require us to incur higher financing costs and would allow, but not in most instances require, counterparties to energy commodity contracts to terminate the contracts and settle the transaction. Also, the failure to maintain investment grade ratings would restrict our access to the wholesale energy markets.

Equity market performance affects our decommissioning trust funds and benefit plan asset values.

The sharp decline in the equity markets since the third quarter of 2000 has reduced the value of the assets held in trusts to satisfy the obligations of pension and postretirement benefit plans and the eventual nuclear generation station decommissioning requirements. If the markets continue to decline, we may have higher funding requirements and pension and other postretirement benefit expense. We will continue to manage the assets in the pension and postretirement benefit plans and nuclear decommissioning trusts in order to achieve the best return possible in conjunction with our overall risk management practices and diversified approach to investment. Please refer to the Critical Accounting Estimates section that more fully describes the quantitative financial statement effects of changes in the equity markets on the nuclear decommissioning trust funds and benefit plan assets.

Our results of operations can be affected by inflation.

Inflation affects us through increased operating costs and increased capital costs for electric plant. As a result of the rate freezes and caps imposed under the legislation in Illinois and Pennsylvania and price pressures due to competition, we may not be able to pass the costs of inflation through to customers.

Other

We may incur substantial cost to fulfill our obligations related to environmental matters.

Our businesses are subject to extensive environmental regulation by local, state and Federal authorities. These laws and regulations affect the manner in which we conduct our operations and make our capital expenditures. These regulations affect how we handle air and water emissions and solid waste disposal and are an important aspect of Generation's operations. In addition, we are subject to liability under these laws for the costs of remediating environmental contamination of property now or formerly owned by us and of property contaminated by hazardous substances we generate. We believe that we have a responsible environmental management and compliance program; however, we have incurred and expect to incur significant costs related to environmental compliance and site remediation and clean-up. Remediation activities associated with manufactured gas plant operations conducted by predecessor companies will be one source of such costs. Also, we 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, 2002, our reserve for environmental investigation and remediation costs was $156 million, exclusive of decommissioning liabilities. We have accrued and will continue to accrue amounts that we believe are prudent to cover these environmental liabilities, but we cannot predict with any certainty whether these amounts will be sufficient to cover our environmental liabilities. We cannot predict whether we will incur other significant liabilities for any additional investigation and remediation costs at additional sites not currently identified by us, environmental agencies or others, or whether such costs will be recoverable from third parties.

Regulations imposed by the Securities and Exchange Commission under the Public Utility Holding Company Act of 1935 affect our business operations.

We are subject to regulation by the Securities and Exchange Commission (SEC) under the Public Utility Holding Company Act (PUHCA) of 1935 as a result of our ownership of ComEd and PECO. That regulation affects our ability to:

- diversify, by generally restricting our investments to traditional electric and gas utility businesses and related businesses;

- issue securities, by requiring the prior approval of the SEC or for ComEd and PECO, requiring the approval of state regulatory commissions; and

- engage in transactions among our affiliates without the SEC's prior approval and, then, only at cost, since the PUHCA regulates business between affiliates in a utility holding company system; and make dividend payments in specified situations.

Our financial performance is affected by our ability to manage costs for security and liability insurance.

- Security

  We do not fully know the impact that future terrorist attacks or threats of terrorism may have on our industry in general and on us in particular. The events of September 11, 2001 have affected our operating procedures and costs. We have initiated security measures to safeguard our employees and critical operations and are actively participating in industry initiatives to identify methods to maintain the reliability of our energy production and delivery systems. We have met or exceeded all security measures mandated by the NRC for nuclear plants after the September 11, 2001 terrorist attacks. These security measures resulted in increased costs in 2002 of $19 million, of which approximately $10 million was capitalized. On a continuing basis, we are evaluating enhanced security measures at certain critical locations, enhanced response and recovery plans and assessing long-term design changes and redundancy measures. Additionally, the energy industry is working with governmental authorities to ensure that emergency plans are in place and critical infrastructure vulnerabilities are addressed in order to maintain the reliability of the country's energy systems. These measures will involve additional expense to develop and implement, but will provide increased assurances as to our ability to continue to operate under difficult times.

  In connection with the events of September 11, 2001, the electric and gas industries have also developed additional security guidelines. The electric industry, through the North American Electric Reliability Council (NERC), developed physical security guidelines, which were accepted by the U.S. Department of Energy. In 2003, FERC is expected to issue minimum standards to safeguard the electric grid system control. These standards are expected to be effective in 2004 and fully implemented by January 2005. The gas industry, through the American Gas Association, developed physical security guidelines that were accepted by the U.S. Department of Transportation. We participated in the development of these guidelines and are using them as a model for our security program.

- Nuclear liability insurance

  The Price-Anderson Act limits the liability of nuclear reactor owners for claims that could arise from a single incident. The current limit is $9.5 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, we carry nuclear liability insurance in the maximum available amount (currently $300 million per site). Claims exceeding that amount are covered through mandatory participation in a financial protection pool. The Price-Anderson Act expired on August 1, 2002, but existing facilities, such as those owned and operated by Generation, remain covered. The U.S. Congress has extended the provisions of the Price-Anderson Act related to commercial facilities through 2003. The extension was passed as part of the Consolidated Appropriations Resolution, 2003, which will be presented to the President of the United States for his signature. The extension would affect facilities obtaining NRC operating licenses in 2003. Existing facilities are unaffected by the extension.

- Other insurance

  In addition to nuclear liability insurance, Exelon also carries property damage and liability insurance for its properties and operations. As a result of significant changes in the insurance marketplace, due in part to the September 11, 2001 terrorist acts, the available coverage and limits may be less than the amount of insurance obtained in the past, and the recovery for losses due to terrorists acts may be limited. We are self-insured for deductibles and to the extent that any losses may exceed the amount of insurance maintained.

  A claim that exceeds the amounts available under our property damage and liability insurance, together with the deductible, would negatively affect our results of operations. Nuclear Electric Insurance Limited (NEIL), a mutual insurance company to which we belong, provides property and business interruption insurance for our nuclear operations. In recent years, NEIL has made distributions to its members. Our distribution for 2002 was $40 million, which was recorded as a reduction to Operating and Maintenance expense on our Consolidated Statements of Income. Due in part to the September 11, 2001 events and the results in the stock market over the last two years, we cannot predict the level of future distributions.

The possibility of attack or war may adversely affect our results of operations, future growth and ability to raise capital.

Any military strikes or sustained military campaign may affect our operations in unpredictable ways, such as further changes in insurance markets, increased security measures and disruptions of fuel supplies and markets, particularly oil and LNG. Just the possibility that infrastructure facilities, such as electric generation, transmission and distribution facilities, would be direct targets of, or indirect casualties of, an act of terror or war may affect our operations. War and the possibility of war may have an adverse effect on the economy in general. A lower level of economic activity might result in a decline in energy consumption, which may adversely affect our revenues or restrict our future growth. Instability in the financial markets as a result of war may affect our ability to raise capital.

The introduction of new technologies could increase competition within our markets.

While demand for electricity is generally increasing throughout the United States, the rate of construction and development of new, more efficient, electric generation facilities and distribution methodologies may exceed increases in demand in some regional electric markets. The introduction of new technologies could increase competition, which could lower prices and have an adverse affect on our results of operations or financial condition.

Results of Operations

Year Ended December 31, 2002 Compared To Year Ended December 31, 2001

Net Income and Earnings Per Share

Net income for 2002 increased $12 million compared to 2001. Diluted earnings per common share were $4.44 and $4.43 for 2002 and 2001, respectively. Net income for 2002 reflects a $230 million charge for the cumulative effect of changes in accounting principles as a result of the adoption of Financial Accounting Standards Board (FASB) Statement of Financial Accounting Standards (SFAS) No. 142, "Goodwill and Other Intangible Assets" (SFAS No. 142), while net income for 2001 reflects $12 million of income for the cumulative effect of changes in accounting principles as a result of the adoption of SFAS No. 133, "Accounting for Derivatives and Hedging Activities" (SFAS No. 133). See Note 4 of the Notes to Consolidated Financial Statements for further information regarding the adoption of SFAS No. 142 and SFAS No. 133.

Income Before Cumulative Effect of Changes in Accounting Principles in 2002 increased $254 million, or 18%, compared to 2001. Diluted earnings per common share on the same basis increased $0.76 per share, or 17%. The increase reflects Enterprises' sale of its interest in AT&T Wireless, a 2.6% increase in retail sales due to a warmer-than-usual summer, an extension of the estimated service lives of generating stations, the discontinuation of goodwill amortization as of January 1, 2002 pursuant to SFAS No. 142, lower interest expense, and reduced depreciation expense resulting from lower depreciation rates at Energy Delivery. The increase was partially offset by lower wholesale energy prices, increased nuclear refueling outage costs, the write-down of certain investments at Enterprises, employee severance costs, and other factors described below.

Results of Operations by Business Segment

All comparisons presented under this heading are comparisons of operating results and other statistical information for 2002 to operating results and other statistical information for 2001. These results reflect intercompany transactions, which are eliminated in our consolidated financial statements.

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

	2002	2001	Variance	% Change
Energy Delivery	$ 1,268	$ 1,022	$ 246	24.1%
Generation	387	512	(125)	(24.4%)
Enterprises	65	(85)	150	176.5%
Corporate	(50)	(33)	(17)	(51.5%)
Total	$ 1,670	$ 1,416	$ 254	17.9%

Net Income (Loss) by Business Segment

	2002	2001	Variance	% Change
Energy Delivery	$ 1,268	$ 1,022	$ 246	24.1%
Generation	400	524	(124)	(23.7%)
Enterprises	(178)	(85)	(93)	(109.4%)
Corporate	(50)	(33)	(17)	(51.5%)
Total	$ 1,440	$ 1,428	$ 12	0.8%

Results of Operations - Energy Delivery

Energy Delivery consists of our regulated energy delivery operations conducted by 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 a public utility under the Illinois Public Utilities Act and is subject to extensive regulation by the ICC as to rates, the issuance of securities and certain other aspects of ComEd's operations. ComEd is also subject to regulation by FERC as to transmission rates and certain other aspects of its business.

ComEd's retail service territory has an area of approximately 11,300 square miles and an estimated population of eight million as of December 31, 2002. The service territory includes the City of Chicago, an area of about 225 square miles with an estimated population of three million. ComEd had approximately 3.6 million customers at December 31, 2002.

PECO is engaged principally in the purchase, transmission, distribution and sale of electricity to residential, commercial and industrial customers and in the purchase, distribution and sale of natural gas to residential, commercial and industrial customers. PECO is a public utility under the Pennsylvania Public Utility Code and is subject to extensive regulation by the PUC as to electric and gas rates, the issuances of securities and certain other aspects of PECO's operations. PECO is also subject to regulation by FERC as to transmission rates, gas pipelines and certain other aspects of its business.

PECO's retail service territory covers approximately 2,100 square miles in southeastern Pennsylvania. PECO provides electric delivery service in an area of approximately 2,000 square miles, with a population of approximately 3.8 million, including 1.5 million in the City of Philadelphia. Natural gas service is supplied in an approximate 2,100 square mile area in southeastern Pennsylvania adjacent to Philadelphia, with a population of approximately 2.3 million. PECO delivers electricity to approximately 1.5 million customers and natural gas to approximately 450,000 customers.

Energy Delivery	2002	2001	Variance	% Change
Operating Revenues	$ 10,457	$10,171	$ 286	2.8%
Revenue, net of Purchased Power & Fuel Expense	5,855	5,699	156	2.7%
Operating Income	2,860	2,593	267	10.3%
Income Before Income Taxes	2,033	1,725	308	17.9%
Net Income	1,268	1,022	246	24.1%

The changes in Energy Delivery's revenue, net of purchased power and fuel expense, for 2002 compared to 2001, included the following:

- increases in weather normalized volumes of $171 million as a result of increases in the number of customers and additional average usage per customer, primarily residential customers,
- positive weather impacts of $84 million, primarily the results of warmer than usual summer weather,
- changes in customer rates resulting in a $54 million decrease to revenue, net of purchased power and fuel expense,
- favorable changes due to customer choice of $30 million, including customers returning to PECO as their energy supplier, or ComEd's customers electing to purchase energy from alternative energy suppliers or electing ComEd's PPO, under which non-residential customers can purchase power from ComEd at a market-based rate,
- increases in PJM ancillary charges of $41 million, which decreased revenue, net of purchased power and fuel expense,
- an $18 million increase in 2002 purchased power expense for ComEd due to an increase in the weighted average on-peak/off-peak cost of electricity,
- a 2001 reversal of a reserve for revenue refunds of $15 million related to certain ComEd municipal customers as a result of a favorable FERC ruling, and
- an increase in revenue, net of purchased power and fuel related to a settlement of CTCs by a large customer of PECO in the amount of $11 million in 2001.

The changes in operating income for 2002 compared to 2001, included the following:

- reduction in amortization expense of $126 million as a result of the discontinuance of goodwill amortization upon the adoption of SFAS No. 142 on January 1, 2002,
- additional gross receipts tax expense of $72 million related to additional revenues and an increase in the gross receipt tax rate on electric revenue effective January 1, 2002 (gross receipts taxes are recorded in Revenues and Taxes Other Than Income and have no impact on net income),
- reduction in depreciation expense of $48 million due to the impact of lower depreciation rates at ComEd effective July 1, 2002,
- increased depreciation expense in 2002 of $34 million due to higher plant in service balances,
- increase in regulatory asset amortization of $30 million in 2002, primarily attributable to additional amortization of PECO's CTCs,
- reduction in 2002 in the allowance for uncollectible accounts related to a change in accounting estimate of $28 million,
- higher corporate allocations, pension and postretirement benefit costs, and executive severance costs totaling $22 million in 2002, and
- lower employee severance costs at PECO of $18 million in 2001 associated with the Merger.

The changes in income before income taxes for 2002 compared to 2001, included the following:

- a decrease in interest expense of $119 million primarily attributable to less outstanding debt and refinancing of existing debt at lower interest rates,
- lower interest income of $74 million resulting from lower interest rates which is primarily attributable to a note receivable from Unicom Investments, Inc., an Exelon subsidiary, and
- the establishment of a reserve of $12 million in 2002 for a probable plant disallowance resulting from an audit performed in conjunction with ComEd's delivery service rate case.

Energy Delivery's effective income tax rate was 37.6% for 2002, compared to 40.8% for 2001. This decrease in the effective tax rate was primarily attributable to a reduction in state income taxes and the discontinuation of goodwill amortization as of January 1, 2002, which was not deductible for income tax purposes in 2001.

Energy Delivery Operating Statistics and Revenue Detail

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

Retail Deliveries - (in gigawatthours (GWhs))(1)	2002	2001	Variance	% Change
Bundled Deliveries (2)				
Residential	37,839	33,355	4,484	13.4%
Small Commercial & Industrial	29,971	29,433	538	1.8%
Large Commercial & Industrial	22,652	23,265	(613)	(2.6%)
Public Authorities & Electric Railroads	7,332	8,645	(1,313)	(15.2%)
Total Bundled Deliveries	97,794	94,698	3,096	3.3%
Unbundled Deliveries (3)				
Alternative Energy Suppliers				
Residential	1,971	3,105	(1,134)	(36.5%)
Small Commercial & Industrial	5,634	4,471	1,163	26.0%
Large Commercial & Industrial	7,652	7,810	(158)	(2.0%)
Public Authorities & Electric Railroads	913	372	541	145.4%
	16,170	15,758	412	2.6%
PPO (ComEd Only)				
Small Commercial & Industrial	3,152	3,279	(127)	(3.9%)
Large Commercial & Industrial	5,131	5,750	(619)	(10.8%)
Public Authorities & Electric Railroads	1,346	987	359	36.4%
	9,629	10,016	(387)	(3.9%)
Total Unbundled Deliveries	25,799	25,774	25	0.1%
Total Retail Deliveries	123,593	120,472	3,121	2.6%

(1) One gigawatthour is the equivalent of one million kilowatthours (kWh).
(2) Bundled service reflects deliveries to customers taking electric service under tariffed rates, which include the cost of energy and the delivery cost of the transmission and the distribution of the energy. PECO's tariffed rates also include a CTC. See Note 6 of the Notes to Consolidated Financial Statements for a discussion of CTC.
(3) Unbundled service reflects customers electing to receive electric generation service from an alternative energy supplier or ComEd's PPO. See Note 5 of the Notes to Consolidated Financial Statements for further discussion of ComEd's PPO.

Electric Revenue	2002	2001	Variance	% Change
Bundled Revenues (1)				
Residential	$ 3,719	$ 3,336	$ 383	11.5%
Small Commercial & Industrial	2,601	2,503	98	3.9%
Large Commercial & Industrial	1,496	1,452	44	3.0%
Public Authorities & Electric Railroads	456	502	(46)	(9.2%)
Total Bundled Revenues	8,272	7,793	479	6.1%
Unbundled Revenues (2)				
Alternative Energy Suppliers				
Residential	145	235	(90)	(38.3%)
Small Commercial & Industrial	159	129	30	23.3%
Large Commercial & Industrial	170	138	32	23.2%
Public Authorities & Electric Railroads	28	6	22	n.m.
	502	508	(6)	(1.2%)
PPO (ComEd Only)				
Small Commercial & Industrial	204	220	(16)	(7.3%)
Large Commercial & Industrial	278	343	(65)	(19.0%)
Public Authorities & Electric Railroads	71	59	12	20.3%
	553	622	(69)	(11.1%)
Total Unbundled Revenues	1,055	1,130	(75)	(6.6%)
Total Electric Retail Revenues	9,327	8,923	404	4.5%
Wholesale and Miscellaneous Revenue (3)	581	594	(13)	(2.2%)
Total Electric Revenue	$ 9,908	$ 9,517	$ 391	4.1%

(1) Bundled revenue reflects deliveries to customers taking electric service under tariffed rates, which include the cost of energy and the delivery cost of the transmission and the distribution of the energy. PECO's tariffed rates also include a CTC charge.
(2) Unbundled revenue reflects revenue from customers electing to receive electric generation service from an alternative energy supplier or ComEd's PPO. Revenue from customers choosing an alternative energy supplier includes a distribution charge and a CTC. Revenues from customers choosing ComEd's PPO includes an energy charge at market rates, transmission, and distribution charges and a CTC. Transmission charges received from alternative energy suppliers are included in wholesale and miscellaneous revenue.
(3) Wholesale and miscellaneous revenues include transmission revenue, sales to municipalities and other wholesale energy sales.
n.m. - not meaningful

The differences in 2002 electric retail revenues as compared to 2001 were attributable to the following:

	Variance
Volume	$ 224
Weather	151
Customer Choice	95
Rate Changes	(54)
Other Effects	(12)
Electric Retail Revenue	$ 404

o Volume. Revenues from higher delivery volume, exclusive of the effect of weather, increased due to an increased number of customers and increased usage per customer, primarily residential.

o Weather. The weather impact was favorable in 2002 compared to 2001 as a result of warmer summer weather in ComEd and PECO service territories. Cooling degree days in the ComEd and PECO service territories were 29% higher and 15% higher, respectively, in 2002 as compared to 2001.

Heating degree days in the ComEd and PECO service territories were 3% higher and 1% higher, respectively, in 2002 as compared to 2001.

- Customer Choice. All ComEd and PECO customers have the choice to purchase energy from other suppliers. This affects revenues from the sale of energy but not revenue from the delivery of electricity since ComEd and PECO continue to deliver electricity that is purchased from other suppliers. As of December 31, 2002, 13% of energy delivered to Energy Delivery's customers was provided by alternative electric suppliers. On May 1, 2002, all ComEd residential customers became eligible to choose their supplier of electricity; however, as of December 31, 2002, no alternative electric supplier had sought approval from the ICC and no electric utilities had chosen to enter the ComEd residential market for the supply of electricity. The increase in electric retail revenues includes increased revenues of $226 million from customers in Pennsylvania who selected or returned to PECO as their electric supplier. The increase was partially offset by a decrease in revenues of $131 million from customers in Illinois electing to purchase energy from an alternative retail electric supplier (ARES) or ComEd's PPO.

- Rate Changes. The decrease in revenues attributable to rate changes reflects $99 million for the 5% ComEd residential rate reduction, effective October 1, 2001, required by the Illinois restructuring legislation and the timing of a $60 million PECO rate reduction in effect for 2001 and 2002, partially offset by $50 million related to an increase in PECO's gross receipts tax rate effective January 1, 2002 and the expiration of a 6% reduction in PECO's rates during the first quarter of 2001.

- Other Effects. The primary other item impacting revenues in 2002 was an $11 million settlement of CTCs by a large PECO customer in the first quarter of 2001.

The reduction in wholesale revenue is primarily attributable to the expiration of wholesale contracts that ComEd had entered into to support the open access program in Illinois and the fact that wholesale revenues for 2001 included a reversal of a $15 million reserve for customer refunds because of a favorable FERC ruling in 2001. The decrease in wholesale revenue was partially offset by a $12 million reimbursement from Generation relating to third-party energy reconciliations.

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

	2002	2001	Variance
Deliveries in millions of cubic feet (mmcf)	85,545	81,528	4,017
Revenue	$549	$654	$(105)

The changes in gas revenue for 2002 as compared to 2001, were as follows:

	Variance
Rate Changes	$ (108)
Weather	2
Volume	1
Gas Revenue	$ (105)

- Rate Changes. The unfavorable variance in rates is attributable to an adjustment of the purchased gas cost recovery by the PUC in December 2001. The average rate per mmcf in 2002 was 20% lower than it was in 2001. PECO's gas rates are subject to periodic adjustments by the PUC and are designed to recover from or refund to customers the difference between actual cost of purchased gas and the amount included in base rates and increases or decreases in certain state taxes not recovered in base rates. Effective December 1, 2002, the PUC approved a reduction in the purchased gas adjustment of 4.5%.

- Weather. The weather impact was favorable, as a result of colder weather in 2002, as compared to 2001. Heating degree-days in PECO's service territory increased 1% in 2002 compared to 2001.
- Volume. Exclusive of weather impacts, higher delivery volume increased revenue by $1 million in 2002 compared to 2001. Total deliveries to customers increased 5% in 2002 compared to 2001, primarily as a result of customer growth and higher transportation volumes.

Results of Operations - 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. During 2002, Generation acquired the generating assets of Sithe New England as well as two generating stations from TXU Corp. Including those acquisitions, Generation directly owns generation assets in the Northeast, Mid-Atlantic, Midwest and Texas regions with a net capacity of 26,762 MWs including 14,547 MWs of nuclear capacity, and also controls another 13,900 MWs of capacity in the Midwest, Southeast and South Central regions through long-term contracts.

In addition to its owned generation facilities, Generation owns a 49.9% interest in Sithe with a call option, that first became available in December 2002, to purchase the remaining 50.1% interest (see further discussion in Liquidity and Capital Resources). Sithe develops, owns and operates 22 generation facilities in North America. Currently, Sithe has a total generating capacity of 1,321 MWs in operation and 230 MWs under construction. Generation also owns a 50% interest in AmerGen, a joint venture with British Energy plc. AmerGen owns three nuclear stations with total generation capacity of 2,481 MWs.

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. Power Team markets any remaining energy in the wholesale and spot markets.

In the second quarter of 2002, Generation early adopted Emerging Issues Task Force (EITF) Issue 02-3 "Accounting for Contracts Involved in Energy Trading and Risk Management Activities" (EITF 02-3). EITF 02-3 was issued by the FASB EITF in June 2002 and required revenues and energy costs related to energy trading contracts to be presented on a net basis in the income statement. For comparative purposes, energy costs related to energy trading have been reclassified as revenue for prior periods to conform to the net basis of presentation required by EITF 02-3.

Generation	2002	2001	Variance	% Change
Operating Revenues	$ 6,858	$6,826	$ 32	0.5%
Revenue, net of Purchased Power & Fuel Expense	2,605	2,831	(226)	(8.0%)
Operating Income	509	872	(363)	(41.6%)
Income Before Income Taxes and Cumulative Effect of Changes in Accounting Principles	604	839	(235)	(28.0%)
Income Before Cumulative Effect of Changes in Accounting Principles	387	512	(125)	(24.4%)
Net Income	400	524	(124)	(23.7%)

The changes in Generation's revenue, net of purchased power and fuel expense, for 2002 compared to 2001, included the following:

- lower margins on market sales attributable to lower average market energy prices,

- increased net trading portfolio losses of $36 million due to lower trading margins primarily resulting from lower purchased power and transmission costs, together with lower wholesale market prices,
- weather-related increases in sales to affiliates,
- lower average supply costs, and
- increased market sales volumes.

The changes in operating income for 2002 compared to 2001, included the following:

- costs incurred for five additional refueling outages of $80 million,
- higher allocated corporate costs, including executive severance,
- increase in 2002 in the allowance for uncollectible accounts related to a change in accounting estimate of $6 million,
- decrease in depreciation and decommissioning expense of $42 million reflecting the extension by Generation in 2001 of the estimated service lives of its generating stations,
- additional depreciation expense of $32 million on generating plants placed in service, including two generating plants that were acquired in April 2002 and a peaking facility placed in service in July 2002,
- costs related to additional security measures of $9 million,
- reduction in Generation's severance accrual of $10 million,
- decrease in expenses of $8 million related to fewer employees, and
- cost reductions related to the Cost Management Initiative.

The changes in income before income taxes for 2002 compared to 2001, included the following:

- improved decommissioning trust investment income during 2002 to $58 million, compared to losses of $60 million in 2001, and
- net decrease in interest expense due to:
    - increased long-term debt resulting in a $21 million increase and
    - reduction in the variable interest rate on the spent nuclear fuel obligation resulting in a decrease of $19 million.

Generation's effective income tax rate was 35.9% for 2002 compared to 39.0% for 2001. This decrease was primarily attributable to tax-exempt interest deductions in 2002 and other tax benefits recorded in 2002.

Cumulative effect of changes in accounting principles recorded in 2002 and 2001 included income of $13 million, net of income taxes, recorded in 2002 related to the adoption of SFAS No. 141 "Business Combinations" (SFAS No. 141) and SFAS No. 142, and income of $12 million, net of income taxes, recorded in 2001 related to the adoption of SFAS No. 133. See Note 4 of the Notes to Consolidated Financial Statements for further discussion of these effects.

Generation Operating Statistics

Generation's sales and the supply of these sales, excluding the trading portfolio, were as follows:

Sales (in GWhs)	2002	2001	% Change
Energy Delivery	118,473	116,917	1.3%
Exelon Energy	5,502	6,876	(20.0%)
Market Sales	83,565	72,333	15.5%
Total Sales	207,540	196,126	5.8%

Supply of Sales (in GWhs)	2002	2001	% Change
Nuclear Generation (1)	115,854	116,839	(0.8%)
Purchases - non-trading portfolio (2)	78,710	67,942	15.8%
Fossil and Hydro Generation	12,976	11,345	14.4%
Total Supply	207,540	196,126	5.8%

(1) Excluding AmerGen.
(2) Including purchased power agreements with AmerGen.

Trading volume of 69,933 GWhs and 5,754 GWhs for 2002 and 2001, respectively, is not included in the table above.

Generation's average margin and other operating data for 2002 and 2001 were as follows:

($/MWh)(1)	2002	2001	% Change
Average Revenue			
Energy Delivery	$ 33.48	$ 32.55	2.9%
Exelon Energy	44.87	41.53	8.0%
Market Sales	30.75	37.00	(16.9%)
Total - excluding the trading portfolio	32.68	34.51	(5.3%)
Average Supply Cost (2) - excluding trading portfolio	$ 20.14	$ 20.26	(0.6%)
Average Margin - excluding the trading portfolio	$ 12.54	$ 14.25	(12.0%)

(1) One megawatthour (MWh) is the equivalent of one thousand kWhs.
(2) Average supply cost includes purchased power and fuel costs.

	2002	2001
Nuclear fleet capacity factor (1)	92.7%	94.4%
Nuclear fleet production cost per MWh (1)	$ 13.00	$ 12.78
Average purchased power cost for wholesale operations per MWh	$ 41.83	$ 45.94

(1) Including AmerGen and excluding Salem.

The factors below contributed to the overall reduction in Generation's average margin for 2002.

Generation's GWh deliveries increased 5.8% in 2002 primarily due to favorable weather conditions, which increased demand for Energy Delivery and increased market sales attributable to the increased supply from acquired generation and power uprates at existing facilities, slightly offset by a decrease in sales to Exelon Energy, Enterprises' retail energy unit, due to lower demand in the eastern energy markets.

Generation's supply mix changed due to:

- increased purchases resulting from the supply agreement with AmerGen's Unit No. 1 at Three Mile Island Nuclear Station facility which was new in 2002,
- decreased nuclear generation due to an increase in the number of refueling outages during 2002, slightly offset by power uprates,
- increased Fossil and Hydro net generation due to the effect of the acquisition of two generating plants in April, a peaking facility placed in service in July and the Sithe New England plants acquired in November, which in total account for an increase of 2,500 GWhs, and strong waterflows which increased the hydro output by 400 GWhs, and
- lower production in our Mid-Atlantic coal and oil units due to cooler summer weather conditions and lower power prices in 2002.

Generation's average revenue was affected by:

- increased weighted average on and off peak prices per MWh for supply agreements with ComEd,
- higher contracted prices from Exelon Energy, impacted by lower actual volumes to those customers, and
- lower market prices.

The lower nuclear capacity factor and increased nuclear production costs are primarily due to 260 days of planned outage time in 2002 versus 153 days in 2001. Nuclear production cost increased from $12.78 to $13.00 primarily due to an $80 million increase in outage costs and the number of refueling outages in 2002 as compared to 2001. These decreases are slightly offset by a $25 million decrease in payroll costs due to headcount reductions and $4 million in lower project expenditures. The decrease in purchased power costs was primarily due to depressed wholesale power market prices.

Results of Operations - Enterprises

Enterprises consists primarily of the infrastructure services business of InfraSource, Inc. (InfraSource), the energy services business of Exelon Services, Inc. (Exelon Services), the competitive retail energy sales business of Exelon Energy, the district cooling business of Exelon Thermal Technologies, Inc., communications joint ventures and other investments weighted towards the communications, energy services and retail services industries.

Enterprises	2002	2001	Variance	% Change
Operating Revenues	$2,033	$2,292	$ (259)	(11.3%)
Operating Income (Loss)	(14)	(77)	63	81.8%
Income (Loss) Before Income Taxes and Cumulative Effect of Changes in Accounting Principles	134	(128)	262	n.m.
Income (Loss) Before Cumulative Effect of Changes in Accounting Principles	65	(85)	150	176.5%
Net Income (Loss)	(178)	(85)	(93)	(109.4%)

n.m. - not meaningful

The changes in Enterprises' operating income (loss) for 2002 compared to 2001, included the following:

- lower revenues of $65 million from Exelon Services as a result of reduced construction projects offset by lower construction costs of $51 million,
- reductions in administrative expenses of $28 million primarily resulting from the Cost Management Initiative,
- reduction of amortization expense of $23 million as result of the discontinuance of goodwill amortization upon the adoption of SFAS No. 142 on January 1, 2002,
- accelerated depreciation of assets relating to Exelon Energy's discontinuance of retail sales in the PJM region of $7 million,
- higher gross margins at Exelon Energy of $28 million, which reflect discontinuing retail sales in the PJM region and improved gas and electricity margins. Energy revenue reductions of $170 million were more than offset by decreases in related cost of $198 million, which included a favorable mark-to-market adjustment of $16 million, and
- higher gross margins at InfraSource of $7 million consisting of:

    - higher infrastructure and construction services revenues of $97 million from an increase in the electric line of business offset by higher infrastructure and construction costs of $53 million, and
    - lower revenues of $117 million as a result of the continued decline of the telecommunications industry and related reduction in construction services offset by lower construction costs of $80 million.

The changes in income (loss) before income taxes for 2002 compared to 2001, included the following:

- a pre-tax gain of $198 million recorded on the AT&T Wireless sale,
- lower interest expense of $23 million due to pay down of debt from proceeds of the AT&T Wireless sale,
- higher equity in earnings of unconsolidated affiliates of $16 million resulting from the discontinuance of losses on AT&T Wireless as a result of its sale,

- write-down of communications investments of $27 million, energy related investment write-downs of $14 million, and a net write-down of other assets of $4 million in 2002 offset by $12 million loss from net write-downs of communications investments, a $1 million loss from an energy related investment, and a net write-down of other assets of $2 million in 2001,
- equity in earnings from a communications joint venture of $9 million primarily relating to its recovery of trade receivables previously considered uncollectible, and
- lower interest income of $7 million.

The effective income tax rate was 50.4% for 2002 compared to 33.3% for 2001. This increase in the effective tax rate was primarily attributable to the AT&T Wireless sale and tax adjustments resulting from various income tax related items of $21 million, partially offset by the discontinuation of goodwill amortization as of January 1, 2002, which was not deductible for income tax purposes in 2001.

The cumulative effect of a change in accounting principle recorded in 2002 due to the adoption of SFAS No. 142 reduced net income by $243 million, net of income taxes. See Note 4 of the Notes to Consolidated Financial Statements.

Year Ended December 31, 2001 Compared to Year Ended December 31, 2000

On October 20, 2000, we became the parent corporation of PECO and ComEd as a result of the Merger. Our results of operations for 2000 consist of PECO's results for the entire year and ComEd's results from October 20, 2000 to the end of the year.

Net Income and Earnings Per Share

Our net income for 2001 increased $842 million, or 144%, compared to 2000. Diluted earnings per share increased $1.56 per share, or 54%. Income before the cumulative effect of changes in accounting principles increased $854 million, or 152%, for 2001. Diluted earnings per share on the same basis increased $1.64 per share, or 60%. Earnings per share increased less than net income as a result of an increase in the weighted average shares of common stock outstanding from the issuance of common stock in connection with the Merger, partially offset by the repurchase of common stock with the proceeds from PECO's May 2000 stranded cost recovery securitization.

Results of Operations by Business Segment

The remaining sections under this heading, "Year Ended December 31, 2001 Compared To Year Ended December 31, 2000," present the operating results for each of our business segments for 2001. All comparisons presented under this heading are comparisons of operating results and other statistical information for 2001 to operating results and other statistical information for 2000. These results reflect intercompany transactions, which are eliminated in our consolidated financial statements.

The October 20, 2000 acquisition of Unicom, and the January 1, 2001 corporate restructuring, significantly impacted our results of operations. To provide a more meaningful analysis of results of operations, the business comparisons below identify the portion of the variance that is attributable to Unicom's results of operations and the portion of the variance that results from normal operations attributable to changes in components of the underlying operations of Exelon. The merger variance represents Unicom results for 2000 prior to the October 20, 2000 acquisition date, the effect of excluding Merger-related costs from Exelon's 2000 operations and an adjustment to reflect results as if the corporate restructuring occurred on January 1, 2000. The 2000 pro forma effects of the Merger and restructuring were developed using estimates of various items, including allocations of corporate overheads to business segments and intercompany transactions.

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

	2001	2000	Variance	Components of Variance: Merger Variance	Components of Variance: Normal Operations
Energy Delivery	$ 1,022	$ 587	$ 435	$ 598	$ (163)
Generation	512	260	252	(1)	253
Enterprises	(85)	(94)	9	(31)	40
Corporate	(33)	(191)	158	115	43
Total	$ 1,416	$ 562	$ 854	$ 681	$ 173

Net Income (Loss) by Business Segment

	2001	2000	Variance	Components of Variance: Merger Variance	Components of Variance: Normal Operations
Energy Delivery	$ 1,022	$ 587	$ 435	$ 598	$ (163)
Generation	524	260	264	(1)	265
Enterprises	(85)	(94)	9	(31)	40
Corporate	(33)	(167)	134	115	19
Total	$ 1,428	$ 586	$ 842	$ 681	$ 161

Results of Operations - Energy Delivery

Energy Delivery	2001	2000	Variance	Components of Variance: Merger Variance	Components of Variance: Normal Operations
Operating Revenues	$ 10,171	$ 4,511	$ 5,660	$ 5,168	$ 492
Revenue, net of Purchased Power & Fuel Expense	5,699	2,725	2,974	2,966	8
Operating Income	2,593	1,502	1,091	1,132	(41)
Income Before Income Taxes	1,725	1,008	717	919	(202)
Net Income	1,022	587	435	598	(163)

Energy Delivery's revenue net of purchased power and fuel expense, in 2001 was comparable to that for 2000.

The changes in Energy Delivery's operating income for 2001 compared to 2000, included the following:

- increased depreciation expense of $43 million, primarily associated with capital additions,
- increased regulatory asset amortization of $34 million, primarily attributable to additional amortization of PECO's CTCs,
- higher administrative and general costs as a result of increased allocation of costs previously recorded at a corporate level, and
- higher employee severance costs of $18 million in 2001 associated with the Merger.

The changes in income before income taxes for 2001 compared to 2000, included the following:

- reduction of $115 million in intercompany interest income in 2001 from Unicom Investments, Inc.,
- gain of $113 million on a forward share repurchase arrangement recognized during the first quarter of 2000,
- lower interest expense due to reductions in the amount of debt outstanding as well as lower interest rates due to debt refinancing,
- non-recurring loss of $38 million on the sale of Cotter Corporation, a ComEd subsidiary, recognized during the first quarter of 2000, and
- additional interest on Transition Bonds issued to securitize PECO's stranded cost recovery.

The effective income tax rate was 40.8% for 2001 compared to 41.8% for 2000. This decrease in the effective tax rate was primarily attributable to a reduction in state income tax.

Energy Delivery's electric sales statistics are as follows:

Retail Deliveries - (GWhs)	2001	2000 (1)	Variance	% Change
Bundled Deliveries (2)				
Residential	33,355	33,322	33	0.1%
Commercial & Industrial	29,433	28,752	681	2.4%
Large Commercial & Industrial	23,265	23,639	(374)	(1.6%)
Public Authorities & Electric Railroads	8,645	8,143	502	6.2%
Total Bundled Deliveries	94,698	93,856	842	0.9%
Unbundled Deliveries (3)				
Alternative Energy Suppliers				
Residential	3,105	1,986	1,119	56.3%
Small Commercial & Industrial	4,471	6,322	(1,851)	(29.3%)
Large Commercial & Industrial	7,810	13,211	(5,401)	(40.9%)
Public Authorities & Electric Railroads	372	598	(226)	(37.8%)
	15,758	22,117	(6,359)	(28.8%)
PPO (ComEd Only)				
Small Commercial & Industrial	3,279	1,433	1,846	128.8%
Large Commercial & Industrial	5,750	2,813	2,937	104.4%
Public Authorities & Electric Railroads	987	1,087	(100)	(9.2%)
	10,016	5,333	4,683	87.8%
Total Unbundled Deliveries	25,774	27,450	(1,676)	(6.1%)
Total Retail Deliveries	120,472	121,306	(834)	(0.7%)

(1) Includes the operations of ComEd as if the Merger occurred on January 1, 2000.
(2) Bundled service reflects deliveries to customers taking electric service under tariffed rates, which include the cost of energy and the delivery cost of the transmission and the distribution of the energy. PECO's tariffed rates also include a CTC. See Note 6 of the Notes to Consolidated Financial Statements for a discussion of CTCs.
(3) Unbundled service reflects customers electing to receive electric generation service from an alternative energy supplier or ComEd's PPO. See Note 5 of the Notes to Consolidated Financial Statements for further discussion of ComEd's PPO.

Electric Revenue	2001	2000 (1)	Variance	% Change
Bundled Revenues (2)				
Residential	$ 3,336	$ 3,348	$ (12)	(0.4%)
Small Commercial & Industrial	2,503	2,371	132	5.6%
Large Commercial & Industrial	1,452	1,343	109	8.1%
Public Authorities & Electric Railroads	502	471	31	6.6%
Total Bundled Revenues	7,793	7,533	260	3.5%
Unbundled Revenues (3)				
Alternative Energy Suppliers				
Residential	235	135	100	74.1%
Small Commercial & Industrial	129	216	(87)	(40.3%)
Large Commercial & Industrial	138	295	(157)	(53.2%)
Public Authorities & Electric Railroads	6	18	(12)	(66.7%)
	508	664	(156)	(23.5%)
PPO (ComEd Only)				
Small Commercial & Industrial	220	92	128	139.1%
Large Commercial & Industrial	343	158	185	117.1%
Public Authorities & Electric Railroads	59	56	3	5.4%
	622	306	316	103.3%
Total Unbundled Revenues	1,130	970	160	16.5%
Total Electric Retail Revenues	8,923	8,503	420	4.9%
Wholesale and Miscellaneous Revenue (4)	594	644	(50)	(7.8%)
Total Electric Revenue	$ 9,517	$ 9,147	$ 370	4.0%

(1) Includes the operations of ComEd as if the Merger occurred on January 1, 2000. Total revenues for Energy Delivery recorded in 2000 were $4.5 billion.
(2) Bundled revenue reflects deliveries to customers taking electric service under tariffed rates, which include the cost of energy and the delivery cost of the transmission and the distribution of the energy. PECO's tariffed rates also include a CTC charge.
(3) Unbundled revenue reflects revenue from customers electing to receive electric generation service from an alternative energy supplier or ComEd's PPO. Revenue from customers choosing an alternative energy supplier includes a distribution charge and a CTC. Revenues from customers choosing ComEd's PPO includes an energy charge at market rates, transmission, and distribution charges and a CTC. Transmission charges received from alternative energy suppliers are included in wholesale and miscellaneous revenue.
(4) Wholesale and miscellaneous revenues include sales to alternative energy suppliers, transmission revenue, sales to municipalities and other wholesale energy sales.

The changes in electric retail revenues for 2001, as compared to 2000, as if the Merger occurred on January 1, 2000, were attributable to the following:

	Variance
Rate Changes	$ 217
Customer Choice	131
Weather	98
Revenue Taxes	(88)
Other Effects	62
Electric Retail Revenue	$ 420

o Rate Changes. The increase in revenues attributable to rate changes reflects the expiration of a 6% reduction in PECO's electric rates in effect for 2000 related to PECO's restructuring settlement, partially offset by a $60 million PECO rate reduction in effect for 2001, and a 5% ComEd residential rate reduction, effective October 1, 2001, required by the Illinois restructuring legislation.

- Customer Choice. All PECO and all ComEd non-residential customers had the choice to purchase energy from other suppliers throughout 2001. The increase in electric retail revenues included increased revenues of $276 million from customers in Pennsylvania who selected or returned to PECO as their electric generation supplier. This was partially offset by a decrease in revenues of $145 million from customers in Illinois electing to purchase energy from an ARES or from ComEd, under the PPO.
- Weather. The weather impact was favorable compared to 2000 as a result of warmer summer weather conditions, although the favorable summer weather conditions were partially offset by unfavorable winter weather conditions, primarily in the ComEd service territory.
- Revenue Taxes. The change in revenue taxes represents a change in presentation of certain revenue taxes for ComEd from operating revenue and tax expense to collections recorded as liabilities resulting from Illinois legislation. This change in presentation does not affect income.
- Other Effects. A strong housing construction market in Chicago contributed to residential and small commercial and industrial customer volume growth, partially offset by the unfavorable impact of a slower economy on large commercial and industrial customers.

The reduction in Wholesale and Miscellaneous revenues in 2001, as compared to 2000, reflects lower off-system sales due to the expiration of wholesale contracts that were offered by ComEd from June 2000 to May 2001 to support the open access program in Illinois, partially offset by increased transmission service revenue and the reversal of a $15 million reserve for revenue refunds to ComEd's municipal customers as a result of a favorable FERC ruling.

Energy Delivery's gas sales statistics were as follows:

	2001	2000	Variance
Deliveries in mmcf	81,528	91,686	(10,158)
Revenue	$654	$532	$122

The changes in gas revenue for 2001, as compared to 2000, were as follows:

	Variance
Price	$ 174
Weather	(38)
Volume	(14)
Gas Revenue	$ 122

- Rate Changes. The favorable variance in price is attributable to an adjustment of the purchased gas cost recovery by the PUC, effective in December 2000. The average price per million cubic feet for all customers for 2001 was 39% higher than 2000. PECO's gas rates are subject to periodic adjustments by the PUC designed to recover or refund the difference between actual cost of purchased gas and the amount included in base rates and to recover or refund increases or decreases in certain state taxes not recovered in base rates.
- Weather. The unfavorable weather impact is attributable to warmer winter weather conditions in the PECO service territory. Heating degree days decreased 12% in 2001 compared to 2000.
- Volume. Exclusive of weather impacts, lower delivery volume affected revenue by $14 million compared to 2000. Total volume of sales to retail customers decreased 11% compared to 2000, primarily as a result of slower economic conditions in 2001 offset by customer growth.

Results of Operations - Generation

Generation	2001	2000	Variance	Components of Variance: Merger Variance	Components of Variance: Normal Operations
Operating Revenues	$ 6,826	$ 3,274	$ 3,552	$ 2,772	$ 780
Revenue, net of Purchased Power & Fuel Expense	2,831	1,428	1,403	1,082	321
Operating Income	872	441	431	23	408
Income Before Income Taxes	839	420	419	(10)	429
Income Before Cumulative Effect of Changes in Accounting Principles	512	260	252	(1)	253
Net Income	524	260	264	(1)	265

The changes in Generation's revenue, net of purchased power and fuel expense, for 2001 compared to 2000, included the following:

- increases in wholesale market prices during the first five months of 2001, particularly in the PJM and Mid-America Interconnected Network regions, which were primarily driven by significant increases in fossil fuel prices,
- higher revenues in 2001 due to the inclusion of charges to affiliates for line losses which were not included in pro forma 2000 revenue,
- mark-to-market gains of $16 million and $14 million on non-trading and trading energy contracts, respectively, offset by realized trading losses of $6 million in 2001, and
- higher nuclear plant output due to increased capacity factors during 2001.

The large concentration of nuclear generation in Generation's portfolio allowed it to capture higher margins in the wholesale market for sales to non-affiliates due to minimal increases in fuel costs.

The changes in operating income for 2001 compared to 2000, included the following:

- reductions in the number of employees,
- fewer nuclear outages in 2001 than in 2000,
- increased decommissioning expense of $140 million reflecting the discontinuance of regulatory accounting practices for certain nuclear generating stations,
- net realized losses on decommissioning trust investments during 2001 of $60 million, and
- additional reserves related to litigation of $30 million.

Other items decreasing net income were an increase in equity in earnings of AmerGen and Sithe of $90 million as a result of acquisitions in 2000 and a reduction in depreciation and decommissioning expense of $90 million attributable to the extension of estimated service lives of Generation's generating plants.

The effective income tax rate was 39.0% for 2001 compared to 38.1% for 2000. This increase in the effective tax rate was primarily attributable to the change in the amortization of investment tax credits. The investment tax credit amortization period was extended as a result of 2001 plant life extensions.

The cumulative effect of a change in accounting principle recorded in 2001 was income of $12 million, net of income taxes, related to the adoption of SFAS No. 133.

For 2001, Generation's sales were 201,879 GWhs, approximately 60% of which were to affiliates. Supply sources were as follows:

Nuclear units	54%
Purchases	37%
Fossil and hydro units	3%
Generation investments	6%
Total	100%

Generation's nuclear fleet, including AmerGen, performed at a weighted average capacity factor of 94.4% for 2001 compared to 93.8% in 2000. Generation's nuclear fleet's production costs, including AmerGen, were $12.78 per MWh for 2001, compared to $14.64 per MWh for 2000.

Results of Operations - Enterprises

				Components of Variance	
Enterprises	2001	2000	Variance	Merger Variance	Normal Operations
Operating Revenues	$ 2,292	$ 1,395	$ 897	$ 467	$ 430
Operating Income (Loss)	(77)	(78)	1	(10)	11
Income (Loss) Before Income Taxes	(128)	(146)	18	(52)	70
Net Income (Loss)	(85)	(94)	9	(31)	40

The changes in Enterprises' operating income (loss) for 2001 compared to 2000, included the following:

- Exelon Energy discontinuing retail sales in the PJM region, which resulted in lower power costs of $193 million offset by lower retail energy sales of $166 million,
- acquisitions by Exelon Services and InfraSource resulted in increased infrastructure and construction revenues of $574 million offset by increased related costs of $554 million,
- increased depreciation and amortization expense of $26 million as a result of goodwill amortization related to acquisitions made by Exelon Services and InfraSource, and
- higher construction costs of $32 million from Exelon Services as a result of increased construction projects offset by higher construction revenues of $26 million.

The changes in income (loss) before income taxes for 2001 compared to 2000, included the following:

- net realized gains on investments of $27 million,
- higher equity in earnings of unconsolidated affiliates of $23 million from lower net losses in communications joint ventures,
- reduced losses of $21 million from sale of assets in 2000, and
- net write-downs on investments of $13 million.

The effective income tax rate was 33.6% for 2001 compared to 35.6% for 2000. This decrease in the effective tax rate was primarily attributable to higher book write-downs of investments in 2001, which were not deductible for income tax purposes.

Liquidity and Capital Resources

Our businesses are capital intensive and require considerable capital resources. These capital resources are primarily provided by internally generated cash flows from Energy Delivery's and

Generation's operations. When necessary, we obtain funds from external sources in the capital markets and through bank borrowings. Our access to external financing at reasonable terms depends on our and our subsidiaries' credit ratings and general business conditions, as well as that of the utility industry in general. If these conditions deteriorate to where we no longer have access to external financing sources at reasonable terms, we have access to a $1.5 billion revolving credit facility which we currently utilize to support our commercial paper program. See the Credit Issues section of Liquidity and Capital Resources for further discussion. We primarily use our capital resources to fund our capital requirements, including construction, investments in new and existing ventures, to repay maturing debt and to pay common stock dividends. Future acquisitions that we may undertake may require external financing, which might include our issuing common stock.

Cash Flows from Operating Activities

Cash flows provided by 2002 operations were consistent with 2001 at $3.6 billion. Energy Delivery and Generation provided approximately 70% and 30%, respectively, of the 2002 cash flows, while Enterprises' contribution was not significant. Energy Delivery's cash flows from operating activities primarily result from sales of electricity and gas to a stable and diverse base of retail customers and are weighted toward the third quarter. Energy Delivery's future cash flows will depend upon the ability to achieve operating cost reductions and the impact of the economy, weather and customer choice on its revenues. Generation's cash flows from operating activities primarily result from the sale of electric energy to wholesale customers, including Energy Delivery and Enterprises. Generation's future cash flows from operating activities will depend upon future demand and market prices for energy and the ability to continue to produce and supply power at competitive prices. Although the amounts may vary from period to period as a result of the uncertainties inherent in business, we expect that Energy Delivery and Generation will continue to provide a reliable and steady source of internal cash flow from operations for the foreseeable future. In the fourth quarter of 2002, we made a discretionary tax-deductible pension plan contribution of $150 million funded by ComEd, Generation and BSC. We also expect to make a discretionary plan contribution in 2003 of $300 million to $350 million.

Cash Flows from Investing Activities

Cash flows used in investing activities for 2002 were $2.5 billion, of which $2.2 billion was used for capital expenditures, compared to $2.4 billion in 2001, of which $2.1 billion was used for capital expenditures. Investing activities in 2002 also includes $445 million for the acquisition of generating plants.

Capital expenditures by business segment for 2002 and projected amounts for 2003 are as follows:

	2002	2003
Energy Delivery	$ 1,041	$ 989
Generation	990	963
Enterprises	44	26
Corporate and Other	75	32
Subtotal	2,150	2,010
Acquisition of Generating Plants	445	--
Total Capital Expenditures and Acquisition of Generating Plants	$ 2,595	$ 2,010

Energy Delivery's estimated capital expenditures for 2003 reflect the continuation of efforts to improve the reliability of its distribution system. Approximately 35% of the budgeted 2003 expenditures are for growth and the remainder are for additions to or upgrades of existing facilities. We anticipate that

Energy Delivery will obtain financing, when necessary, through borrowings, the issuance by PECO or ComEd, or both, of preferred securities or capital contributions made by us.

Generation purchased two natural-gas and oil-fired generating plants from TXU on April 25, 2002. The $443 million purchase was funded with commercial paper, which Exelon issued and Generation is repaying from cash flows from operations. The balance of Generation short-term borrowings at December 31, 2002 attributable to the TXU purchase was approximately $70 million. Investing activities also include a $2 million use of cash for the November 1, 2002 purchase of Sithe New England. The $2 million use is net of $12 million of cash acquired. The remainder of the purchase was financed with a $534 million note to Sithe. In 2002, Generation agreed to make a loan to AmerGen of up to $100 million, at an interest rate of one-month LIBOR plus 2.25%, and with a maturity date of July 1, 2003. As of December 31, 2002, the balance of the loan to AmerGen was $35 million.

We project that Generation's capital expenditures in 2003 will be lower than they were in 2002, and the majority of these expenditures will be used for additions and upgrades to existing facilities, nuclear fuel and increases in capacity at existing plants. Eight nuclear refueling outages are planned for 2003, compared to 11 during 2002. We project that the total capital expenditures for nuclear refueling outages will decrease in 2003 over 2002 by $10 million. Generation has agreed to make capital contributions to AmerGen of 50% of the purchase price of any acquisitions that AmerGen makes. We anticipate that Generation's capital expenditures will be funded by internally generated funds, Generation's borrowings or capital contributions from us.

Enterprises' capital expenditures were $44 million in 2002. Enterprises' capital expenditures for 2002 were primarily for additions to or upgrades of existing facilities. On April 1, 2002, Enterprises sold its 49% interest in AT&T Wireless for $285 million in cash.

We project that Enterprises' capital expenditures for 2003 will be approximately $26 million, primarily for additions to or upgrades of existing facilities. We anticipate that all of Enterprises' capital expenditures will be funded by internally generated funds, capital contributions or borrowings from us.

Our total estimated capital expenditures in 2003 are approximately $2.0 billion. Internally generated cash flow is expected to meet capital requirements excluding acquisitions. Our proposed capital expenditures and other investments are subject to periodic review and revision to reflect changes in economic conditions and other factors.

Cash Flows from Financing Activities

Cash flows used in financing activities were $1.1 billion in 2002, as compared to $1.3 billion in 2001, due to lower dividend payments, a contribution from a minority interest, and increased employee stock purchase plan activity. The primary components of 2002 financing activity are as follows:

- ComEd issued $700 million of First Mortgage Bonds and pollution control bonds to redeem $700 million of First Mortgage Bonds and pollution control bonds. ComEd also paid at maturity $500 million of First Mortgage Bonds and other long-term debt, retired $340 million of transitional trust notes and had net issuances of $123 million of commercial paper.

- PECO issued $225 million of First and Refunding Mortgage Bonds. The proceeds of these bonds were used to repay commercial paper that it used to pay at maturity $222 million of First and Refunding Mortgage Bonds. PECO made principal payments of $326 million on transition bonds and net issuances of $200 million of commercial paper.

On January 22, 2003, ComEd issued $350 million of 3.70% First Mortgage Bonds, due on February 1, 2008 and $350 million of 5.875% First Mortgage Bonds, due on February 1, 2033. These bond proceeds were used to refinance long-term debt that had been retired during the third and fourth quarters of 2002.

The 2001 common stock dividend payments of $583 million cover the period from October 20, 2000, the date of the Merger, through the end of 2001. The 2002 cash dividend payments on common stock were $563 million. On January 28, 2003, our Board of Directors declared a quarterly dividend of $0.46 per share representing an annual dividend rate of $1.84 per share, which is an increase of $0.08 per share over 2002. We intend to grow our dividend over time at a rate of approximately 4% to 5%, commensurate with long-term earnings growth. The payment of future dividends is subject to approval and declaration by the Board of Directors each quarter.

Financing activities in 2002 exclude the non-cash issuance of a $534 million note to Sithe for the November 1, 2002 acquisition of Sithe New England and approximately $1.0 billion of Sithe New England long-term debt, which is reflected in our Consolidated Balance Sheets as of December 31, 2002.

Credit Issues

We meet our short-term liquidity requirements primarily through the issuance of commercial paper by the Exelon corporate holding company (Exelon Corporate) and by ComEd, PECO and Generation. Exelon Corporate participates, along with ComEd, PECO and Generation, in a $1.5 billion unsecured 364-day revolving credit facility with a group of banks. The credit facility that became effective on November 22, 2002, includes a term-out option that allows any outstanding borrowings at the end of the revolving credit period to be repaid on November 21, 2004. Exelon Corporate may increase or decrease the sublimits of each of the participants upon written notification to the banks. As of December 31, 2002, Exelon Corporate's sublimit was $900 million, ComEd's was $200 million, PECO's was $400 million and there was no sublimit for Generation. The credit facility is used principally to support the commercial paper programs of Exelon Corporate, ComEd, PECO and Generation. At December 31, 2002, our Consolidated Balance Sheet reflects the $948 million of commercial paper outstanding, of which $267 million was classified as long-term debt.

For 2002, the average interest rate on notes payable was approximately 1.88%. Certain of the credit agreements to which Exelon Corporate, ComEd, PECO and Generation are parties require them to maintain a 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 attributed to securitization debt, certain changes in working capital, distributions on preferred securities of subsidiaries and in the case of Exelon Corporate and Generation, interest on Sithe New England's debt. Exelon Corporate is measured at the Exelon consolidated level. The following table summarizes the threshold reflected in the credit agreement that the ratio cannot be less than for the twelve-month period ended December 31, 2002:

	Credit Agreement Threshold
Exelon Corporate	2.65 to 1
ComEd	2.25 to 2
PECO	2.25 to 1
Generation	3.25 to 1

At December 31, 2002, we were in compliance with the credit agreement thresholds.

At December 31, 2002, our capital structure consisted of 60% of long-term debt, 32% common equity, 5% notes payable and 3% preferred securities of subsidiaries. Total debt included $6.2 billion of securitization debt constituting obligations of certain consolidated special purpose entities, representing 26% of capitalization. These consolidated special purpose entities were created for the sole purpose of issuing debt obligations to securitize intangible transition property and CTC's of Energy Delivery. Shareholders' equity was reduced by $1 billion in 2002 due to the recording of a minimum pension liability.

To provide an additional short-term borrowing option that will generally be more favorable to the borrowing participants than the cost of external financing, we operate an intercompany utility-money pool. Participation in the money pool is subject to authorization by Exelon's corporate treasurer. ComEd and its subsidiary, Commonwealth Edison Company of Indiana, Inc., PECO, Generation and BSC may participate in the money pool as lenders and borrowers, and Exelon Corporate as a lender. Contributions to and permitted borrowings from the money pool are based on whether the contributions and borrowings result in economic benefits to all the participants. Interest on borrowings is based on short-term market rates of interest, or, if from an external source, specific borrowing rates. There were no material money pool transactions in 2002.

Our access to the capital markets, including the commercial paper market, and our financing costs in those markets depend on the securities ratings of the entity that is accessing the capital markets. None of our borrowings are subject to default or prepayment as a result of a downgrading of securities ratings although such a downgrading could increase fees and interest charges under our $1.5 billion credit facility, and certain other credit facilities. From time to time, we enter into energy commodity and other contracts that require the maintenance of investment grade ratings. Failure to maintain investment grade ratings would allow counterparties to certain energy commodity contracts to terminate the contracts and settle the transactions on a net present value basis. The following table shows our securities ratings at December 31, 2002:

	Securities	Moody's Investors Service	Standard & Poors Corporation	Fitch Investors Service, Inc
Exelon	Senior unsecured debt	Baa2	BBB+	BBB+
	Commercial paper	P2	A2	F2
ComEd	Senior secured debt	A3	A-	A-
	Commercial paper	P2	A2	F2
PECO	Senior secured debt	A2	A	A
	Commercial paper	P1	A2	F1
Generation	Senior unsecured debt	Baa1	A-	BBB+
	Commercial paper	P2	A2	F2

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.

We obtained an order from the SEC under PUHCA authorizing through March 31, 2004, financing transactions, including the issuance of common stock, preferred securities, long-term debt and short-term debt in an aggregate amount not to exceed $4 billion. As of December 31, 2002, there was $1.8 billion of financing authority remaining under the SEC order. Our request for an additional $4 billion in financing authorization is pending with the SEC. The current order limits our short-term debt outstanding to $3 billion of the $4 billion total financing authority. Our request that the short-term debt sub-limit restriction be eliminated is pending with the SEC. The SEC order also authorized us to issue guarantees of up to $4.5 billion outstanding at any one time. At December 31, 2002, Exelon had provided $1.5 billion of guarantees. See Contractual Obligations, Commercial Commitments and Off Balance Sheet Obligations in this section for further discussion of guarantees. The SEC order requires us to maintain a ratio of common equity to total capitalization (including securitization debt) on and after June 30, 2002 of not less than 30%. Exelon expects that it will maintain a common equity ratio of at least 30%.

Under PUHCA, Exelon, ComEd, PECO and Generation can pay dividends only from retained, undistributed or current earnings. However, the SEC order granted permission to ComEd, and to us, to the extent we receive dividends from ComEd paid from ComEd additional paid-in-capital, to pay up to $500 million in dividends out of additional paid-in capital, although Exelon may not pay dividends out of paid-in capital after December 31, 2002 if its common equity is less than 30% of its total capitalization. At December 31, 2002, Exelon had retained earnings of $2.0 billion, including ComEd's retained earnings of $577 million, PECO's retained earnings of $401 million and Generation's undistributed earnings of $924 million. We are also limited by order of the SEC under PUHCA to an aggregate investment of $4 billion in exempt wholesale generators (EWGs) and foreign utility companies (FUCOs). At December 31, 2002, we had invested $2.1 billion in EWGs, leaving $1.9 billion of investment authority under the order. Our request for an additional $1.5 billion in EWG investment authorization is pending with the SEC.

During 2001, we loaned $150 million to Sithe. Sithe paid $2 million in interest on this loan and fully repaid the principal balance in December of 2001 from the proceeds of a bank borrowing. In connection with a bank borrowing by Sithe, we provided the lenders with a support letter confirming our investment in Sithe and agreeing to maintain a positive net worth in Sithe. We expect that Sithe's net worth will remain positive for the foreseeable future and, accordingly, this agreement is not reflected in the following Contractual Obligations, Commercial Commitments and Off Balance Sheet Obligations discussion. This agreement does not guarantee any debt or obligation of Sithe.

Contractual Obligations, Commercial Commitments and Off Balance Sheet Obligations

Our contractual obligations as of December 31, 2002 representing cash obligations that we consider to be firm commitments are as follows:

		Payment due within			
	Total	2003	2004-2005	2006-2007	Due 2008 and beyond
Long-Term Debt	$ 14,595	$ 1,669	$ 2,275	$ 2,445	$ 8,206
Notes Payable	681	681	--	--	--
Short-Term Note to Sithe	534	534	--	--	--
Operating Leases	895	77	117	103	598
Purchase Obligations	14,729	2,677	2,987	1,856	7,209
Spent Nuclear Fuel Obligation	858	--	--	--	858
Obligation to Minority Shareholders	54	3	6	6	39
Total Contractual Obligations	$ 32,346	$ 5,641	$ 5,385	$ 4,410	$ 16,910

For additional information about:

- long-term debt see Note 13 of the Notes to Consolidated Financial Statements
- notes payable see Note 12 of the Notes to Consolidated Financial Statements
- short-term note to Sithe see Note 3 of the Notes to Consolidated Financial Statements
- operating leases see Note 19 of the Notes to Consolidated Financial Statements
- purchase obligations see Note 19 of the Notes to Consolidated Financial Statements
- the spent nuclear fuel obligation see Note 11 of the Notes to Consolidated Financial Statements

- the obligation to minority shareholders see Note 19 of the Notes to Consolidated Financial Statements

We have a long-term supply agreement through December 2022 with Distrigas to guarantee physical gas supply to our New England generating units. Under the agreement, prices are indexed to New England gas markets.

Generation has an obligation to decommission its nuclear power plants. Our current estimate of decommissioning costs for the nuclear plants owned by Generation is $7.4 billion in current year (2003) dollars. Nuclear decommissioning activity occurs primarily after a plant is retired. Based on the extended license lives of our nuclear plants, we will begin decommissioning our plants from 2014 through 2056, with expenditures primarily occurring when our operating plants are decommissioned, during the period from 2029 through 2056. At December 31, 2002, the decommissioning liability, which is recognized over the life of the plant, was recorded in our Consolidated Balance Sheets as Accumulated Depreciation and Deferred Credits and Other Liabilities in the amounts of $2.8 billion and $1.4 billion, respectively. To fund future decommissioning costs, Generation held $3.1 billion of investments in trust funds, including net unrealized gains and losses, at December 31, 2002.

Our commercial commitments as of December 31, 2002, representing commitments not recorded on the balance sheet but potentially triggered by future events, including obligations to make payment on behalf of other parties and financing arrangements to secure our obligations, are as follows:

		Expiration within			
	Total	2003	2004-2005	2006-2007	2008 and beyond
Credit Facility (a)	$ 1,500	$ 1,500	$ --	$ --	$ --
Letters of Credit (non-debt) (b)	111	106	5	--	--
Letters of Credit (Long-Term Debt) (c)	456	305	151	--	--
Insured Long-Term Debt (d)	254	--	--	--	254
Guarantees of Letters of Credit (e)	226	226	--	--	--
Performance Guarantees (f)	101	--	--	--	101
Surety Bonds (g)	521	329	57	4	131
Energy Marketing Contract Guarantees (h)	124	114	10	--	--
Nuclear Insurance Guarantees (i)	1,380	--	--	--	1,380
Lease Guarantees (j)	13	--	--	2	11
Preferred Securities (k)	128	--	--	--	128
Sithe New England Equity Guarantee (l)	38	38	--	--	--
Guarantees of Long-Term Debt (m)	41	2	--	--	39
Total Commercial Commitments	$ 4,893	$ 2,620	$ 223	$ 6	$ 2,044

(a) Credit Facility - Exelon, along with ComEd, PECO, and Generation, maintain a $1.5 billion 364-day credit facility to support commercial paper issuances. At December 31, 2002, there were no borrowings against the credit facility. Additionally, at December 31, 2002, there was $948 million of commercial paper outstanding.
(b) 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.
(c) Letters of Credit (Long-Term Debt) - Direct-pay letters of credit issued in connection with variable-rate debt in order to provide liquidity in the event that it is not possible to remarket all of the debt as required following specific events, including changes in the basis of determining the interest rate on the debt.
(d) Insured Long-Term Debt - Borrowings that have been credit-enhanced through the purchase of insurance coverage equal to the amount of principal outstanding plus interest.
(e) Guarantees of letters of credit - Guarantees issued to provide support for letters of credit as required by third parties. These guarantees could be called upon only in the event of non-payment by a subsidiary.
(f) Performance Guarantees - Guarantees issued to ensure execution under specific contracts.
(g) Surety Bonds - Guarantees issued related to contract and commercial surety bonds, excluding bid bonds.
(h) Energy Marketing Contract Guarantees - Guarantees issued to ensure performance under energy commodity contracts.

(i) Nuclear Insurance Guarantees - Guarantees of nuclear insurance required under the Price-Anderson Act. $1.1 billion of this total exposure is exempt from the $4.5 billion PUHCA guarantee limit by SEC rule.
(j) Lease Guarantees - Guarantees issued to ensure payments on building leases.
(k) Preferred Securities - Guarantees issued to guarantee the preferred securities of the subsidiary trusts of PECO. See Note 16 of the Notes to Consolidated Financial Statements for further information.
(l) Sithe New England Equity Guarantee - See Note 3 of the Notes to Consolidated Financial Statements for further information on the $38 million guarantee. After construction of the SBG facilities is complete, Exelon could be required to guarantee up to an additional $42 million in order to ensure that the SBG facilities have adequate funds available for potential outage and other operating costs and requirements.
(m) Guarantees of Long-Term Debt - Issued to guarantee payment of subsidiary debt.

Sithe Boston Generation Project Debt. We participate in a $1.25 billion credit facility, most of which is available to finance the construction projects of Sithe Boston Generating, LLC (the SBG Facility). The outstanding balance of this facility at December 31, 2002 was $1.0 billion. The SBG Facility provides that if these construction projects are not completed by June 12, 2003, the SBG Facility lenders will have the right, but will not be required, to, among other things, declare all amounts then outstanding under the SBG Facility and the interest rate swap agreements to be due. Generation believes that the construction projects will be substantially complete by May 31, 2003, but that all of the approvals required under the SBG Facility may not be issued by that date. Generation is currently evaluating whether the requirements of the SBG Facility relating to the construction projects can be satisfied by June 12, 2003. In the event that the requirements are not expected to be satisfied by June 12, 2003, Generation will contact the SBG Facility lenders concerning an amendment or waiver of these provisions of the SBG Facility. Generation currently expects that arrangements for such an amendment or waiver, if necessary, can be successfully negotiated with the SBG Facility lenders.

Unconsolidated Equity Investments. Generation is a 49.9% owner of Sithe and accounts for the investment as an unconsolidated equity investment. The Sithe New England purchase did not affect the accounting for Sithe as an equity investment. Separate from the Sithe New England transaction, Generation is subject to a Put and Call Agreement (PCA) that gives Generation the right to purchase (Call) the remaining 50.1% of Sithe, and gives the other Sithe shareholders the right to sell (Put) their interest to Generation. If the Put option is exercised, Generation has the obligation to complete the purchase. At the end of this exercise period, which is December 2005, if Generation has not exercised its Call option and the other stockholders have not exercised their Put rights, Generation will have an additional one-time option to purchase shares from the other stockholders to bring Generation's ownership in Sithe from the current 49.9% to 50.1% of Sithe's total outstanding common stock.

The PCA originally provided that the Put and Call options became exercisable as of December 18, 2002 and expired in December 2005. However, upon Apollo Energy, LLC's (Apollo) purchase of Vivendi's 34.2% ownership and Sithe management's 1% share, Apollo agreed to delay the effective date of its Put right until June 1, 2003 and, if certain conditions are met, until September 1, 2003. There are also certain events that could trigger Apollo's Put right becoming effective prior to June 1, 2003 including Exelon being downgraded below investment grade by Standard and Poor's Rating Group or Moody's Investors Service, Inc., a stock purchase agreement between Exelon and Apollo being executed and subsequently terminated, or the occurrence of any event of default, other than a change of control, under certain Exelon or Apollo credit agreements. Depending on the triggering event, the put price of approximately $460 million, growing at a market rate of interest, needs to be funded within 18 or 30 days of the Put being exercised. There have been no changes to the Put and Call terms with respect to Marubeni's remaining 14.9% interest.

The delay in the effective date of Apollo's Put right allows us to explore a further restructuring of our investment in Sithe. We are continuing discussions with Apollo and Marubeni regarding restructuring alternatives that are designed in part to resolve our ownership limitations of Sithe's qualifying facilities. We would hope to implement any additional restructuring of our Sithe investment in

2003. If we are unsuccessful in restructuring the Sithe transaction, we will proceed to implement measures to address the ownership of the qualified facilities as well as divest non-strategic assets, for which the financial outcome is uncertain.

If Generation exercises its option to acquire the remaining outstanding common stock in Sithe, or if all the other stockholders exercise their Put Rights, the purchase price for Apollo's 35.2% interest will be approximately $460 million, growing at a market rate of interest. The additional 14.9% interest will be valued at fair market value subject to a floor of $141 million and a ceiling of $290 million.

If Generation increases its ownership in Sithe to 50.1% or more, Sithe may become a consolidated subsidiary and our financial results may include Sithe's financial results from the date of purchase. At December 31, 2002, Sithe had total assets of $2.6 billion and total debt of $1.3 billion. This $1.3 billion includes $624 million of subsidiary debt incurred primarily to finance the construction of six new generating facilities, $461 million of subordinated debt, $103 million of line of credit borrowings, $43 million of current portion of long-term debt and capital leases, $30 million of capital leases, and excludes $453 million of non-recourse project debt associated with Sithe's equity investments. For the year ended December 31, 2002, Sithe had revenues of $1.0 billion. As of December 31, 2002, Generation had a $478 million equity investment in Sithe.

Additionally, the debt on the books of our unconsolidated equity investments and joint ventures is not reflected on our Consolidated Balance Sheets. We estimate that this debt, including the $1.3 billion of Sithe's debt described in the preceding paragraph, totals approximately $1.3 billion and that our portion of that amount, based on our ownership interest in the investments, is approximately $673 million.

Generation's equity investment in AmerGen was $160 million and $95 million at December 31, 2002 and 2001, respectively. Generation and British Energy plc (British Energy), Generation's joint venture partner in AmerGen, have each agreed to provide up to $100 million to AmerGen at any time that the Management Committee of AmerGen determines that, in order to protect the public health and safety and/or to comply with NRC requirements, these funds are necessary to meet ongoing operating expenses or to safely maintain any AmerGen plant. The current financial condition of British Energy has been the focus of media attention recently. We cannot predict the ability of British Energy to provide funds to AmerGen. However, we do not believe this will impact AmerGen's ability to conduct its business.

PECO Accounts Receivable Agreement. PECO is party to an agreement with a financial institution under which it can sell an undivided interest, adjusted daily, in up to $225 million of designated accounts receivable until November 2005. PECO entered into this agreement to diversify its funding sources at favorable floating interest rates. At December 31, 2002, PECO had sold a $225 million interest in accounts receivable, consisting of an $164 million interest in accounts receivable, which we 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," and a $61 million interest in special agreement accounts receivable, which we accounted for as a long-term note payable. 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, 2002 and 2001, PECO met this requirement.

Insurance Coverage. We carry property damage, decontamination and premature decommissioning insurance for each station loss resulting from damage to its nuclear plants. Additionally, through our subsidiaries, we are a member of an industry mutual insurance company that provides replacement power cost insurance in the event of a major accidental outage at a nuclear station. Finally, we participate 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 19 of the Notes to Consolidated Financial Statements for further discussion of nuclear insurance.

Critical Accounting Estimates

The preparation of financial statements in conformity with Generally Accepted Accounting Principles 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 estimates and assumptions with its Accounting and Disclosure Governance Committee on a regular basis and provides periodic updates to the Audit Committee of the Board of Directors on management decisions. Management believes that the following areas require significant management judgment in making estimates and assumptions to describe matters that are inherently uncertain and that may change in subsequent periods.

Accounting for Derivative Instruments

We use derivative financial instruments primarily to manage commodity price and interest rate risks. In connection with our Risk Management Policy (RMP), we:

- use financial derivatives to manage our exposure to interest rate fluctuations related to our variable rate debt instruments, changes in interest rates related to planned future debt issuances prior to their actual issuance and changes in the fair value of outstanding debt which we are planning to retire early,

- enter into derivatives to manage the physical and financial risks associated with our energy supply and load obligations, and

- enter into energy related derivatives for trading or speculative purposes.

Our derivative activities are subject to the management, direction, and control of our Risk Management Committee (RMC). The RMC sets forth risk management philosophy and objectives, and establishes procedures for control, valuation, counterparty credit approval, and the monitoring and reporting of our activities in derivative markets and the performance of our derivative contracts.

We 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 changes in the fair value we expect in deciding whether or not to enter into derivative transactions, and in determining the initial accounting treatment for derivative transactions.

We account for derivative financial instruments under SFAS No. 133. To the extent that changes in SFAS No. 133 modify current guidance, including the standards for determining whether contracts can be accounted for as normal purchases and normal sales, the accounting treatment for derivatives may change.

We are required under SFAS No. 133 to record derivative instruments at fair value. Depending on the designation of the derivative, the fair value is either recorded in the income statement or as a component of other comprehensive income in shareholders' equity (OCI). We use 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, we use internal models to determine the fair value. These internal models include assumptions of the future prices of energy based on the specific energy market the energy is being purchased in using externally available forward market pricing curves for all periods possible under the pricing model. We use the Black model, a standard industry valuation model, to determine the fair value of energy derivative contracts that are marked-to-market. To determine the fair value of our outstanding interest rate swap agreements we use external broker quotes or calculate the fair value internally using the Bloomberg swap valuation tool. This tool uses the most recent market inputs and a widely accepted valuation methodology.

During 2002, Generation recognized unrealized and realized net gains of $6 million and $20 million, respectively, relating to mark-to-market adjustments of certain non-trading power purchase and sale contracts pursuant to SFAS No. 133 and unrealized and realized net losses aggregating $9 million and $20 million, respectively, relating to mark-to-market adjustments of derivative instruments entered into for trading purposes.

Hedge Accounting. As part of our energy marketing business, we enter into contracts to purchase or sell electricity, gas and ancillary products such as transmission rights, congestion credits and emission allowances, using contracts that are considered derivatives under SFAS No. 133. Certain of these derivatives qualify as hedge transactions.

A derivative 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). To qualify for hedge accounting, the fair value changes in the derivative must be expected to offset 80%-120% of the changes in fair value or cash flows of the hedged item. Changes in the fair value of a derivative that is designated and qualifies as a fair value hedge and is highly effective, along with the gain or loss on the hedged asset or liability that is attributable to the hedged risk, are recorded in earnings. Changes in the fair value of a derivative that is designated as and qualifies as a cash flow hedge and is highly effective, are recorded in OCI, until earnings are affected by the variability of cash flows being hedged. Exelon continually assesses these cash flow hedges to determine if they continue to be effective and that the forecasted future transaction is probable. At the point in time that the contract does not meet the effective or probable criteria of SFAS No. 133, hedge accounting is discontinued and the fair value of the derivative is recorded through earnings.

Energy Contracts. We enter into contracts designated as cash flow hedges in which we manage the variability of our cash flows related to the purchase or sale of energy. At the initiation of the contract the contract is identified as a cash flow hedge, which requires us to determine whether the contract is in accordance with our RMP, that the forecasted future transaction is probable, and that 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 an energy contract designated as a hedge. An example of a contract that would qualify for hedge accounting would be a forward over-the-counter sales contract used to hedge an expected sale of generation exposed to market prices.

Interest Rate Derivative Instruments. We enter into interest rate swap contracts related to variable rate debt in order to convert the variable interest payments into fixed interest payments to manage the variability of cash flows. Additionally, we enter into forward starting interest rate swaps in order to lock in an interest rate at a future date in anticipation of a future debt issuance to manage the variability of changes in interest rates between the date of the decision to issue and the actual date of issue.

We also enter into interest rate swap contracts related to fixed rate debt in order to maintain our targeted percentage of variable rate debt.

The fair value of derivatives generally reflects the estimated amounts that we would receive or pay to terminate the contracts at the balance sheet date, thereby taking into account the current unrealized gains or losses of open contracts.

Normal Purchases and Normal Sales Exemption. As part of our energy marketing business, we enter into contracts to purchase or sell electricity, gas and ancillary products such as transmission rights, congestion credits and emission allowances using contracts that are considered derivatives under SFAS No. 133. The majority of these contracts, however, qualify for the normal purchases and normal sales SFAS No. 133 exemption from mark-to-market accounting treatment as they are for the purchase and sale of energy to meet the requirements of our 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 in quantities we expect to use or sell over a reasonable period in the normal course of business.

These contracts are reflected in the financial statements at the lower of cost or market, on a portfolio basis, using the accrual method of accounting. We did not have any loss contracts as of December 31, 2002. Under these contracts we recognize any gains or losses when the underlying physical transaction affects earnings. At the initiation of the contract, we make a determination as to whether or not the contract meets the criteria as a normal purchase or normal sale. An example of an energy contract that would qualify for the normal sale exemption would include a forward sale contract under which we expect to supply the full requirements of the counterparty. An example of a contract that would qualify for the normal purchase exemption would be an energy capacity contract that we enter into to satisfy the needs of our customer base, either retail or wholesale.

The availability of the normal purchases and normal sales exemption to specific contracts is based on a determination that at certain times excess generation is available for a forward sale and, similarly, a determination that at certain times generation supply will be insufficient to serve our load. The determination of the ability and intent to deliver or take delivery is based on internal models that forecast customer demand and electricity 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. Significant changes in these assumptions could result in contracts being considered differently under SFAS No. 133 and the potential requirement of mark-to-market accounting.

Proprietary Trading. As part of our energy trading operation, we enter into contracts to buy and sell energy for trading purposes. These contracts are recognized on the balance sheet at fair value and changes in the fair value are recognized through earnings. All proprietary trading activity is recorded net in revenue. Trading activities are a very small portion of Exelon's overall power marketing activities. The trading portfolio is subject to stringent risk management limits and policies, including volumetric and depression limits to manage exposure to market risk, as prescribed by the RMC.

Non-Trading Contracts. To manage our commodity risk exposure and meet our load requirements, we have also entered into non-trading contracts that do not meet the definition in SFAS No. 133 of a normal purchase or normal sale or meet the requirements for hedge accounting treatment. These non-trading contracts are marked-to-market when the underlying item affects earnings with the gains and losses recorded in Purchased Power and Fuel expense. Non-trading contracts are subject to stringent risk management limits and policies, as prescribed by the RMC.

Although we use derivative instruments to assist in managing commodity price and interest rate risks, we can still experience earnings volatility from period to period because of the risks associated with marketing and trading electricity and other energy-related products.

Regulatory Assets and Liabilities

Energy Delivery's operating subsidiaries, ComEd and PECO, are regulated by their respective state regulatory commissions as well as by FERC. The regulators in Illinois and Pennsylvania, as well as FERC, use cost-based rate structures to determine the rates we will charge customers. In establishing cost-based rates, the ICC and the PUC may consider the capital requirements and working capital needs to operate the distribution and transmission business, determine the operating cost levels that can be passed on to customers and provide for a reasonable return to our shareholders. In their determination of rates, the ICC and PUC may include allowable costs in periods other than the periods in which an unregulated entity would record the costs in the income statement. These costs are accounted for as either a regulatory asset or liability. 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. Regulatory assets and liabilities are accounted for under SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation" (SFAS No. 71). Use of SFAS No. 71 is applicable to our utility operations that meet the following criteria: the operations are subject to third-party regulation of rates; the rates are cost-based; and the assumption that all costs will be recoverable from customers through rates is appropriate and reasonable. If a separable portion of our business no longer meets these criteria, we are required to eliminate the financial statement effects of regulation for that part of our business.

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. Current rates include the recovery of our existing regulatory assets.

The most significant regulatory assets we have recorded are:

- Competitive Transition Charges: These charges represent PECO's stranded costs that the PUC determined would be allowed to be recoverable through regulated rates. These costs are related to the deregulation of the generation portion of the electric utility business in Pennsylvania. The unamortized balance of the CTC of $4.6 billion and $4.9 billion as of December 31, 2002 and 2001, respectively, was recorded on our Consolidated Balance Sheets. The CTC includes Intangible Transition Property sold to PECO Energy Transition Trust, a wholly owned 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 rate of return on the unamortized balance of 10.75%.

- Recoverable Transition Costs: These charges, related to the recovery of ComEd's former generating plants, are amortized based on the expected return on equity of ComEd in any given year. At December 31, 2002 and 2001, we had $175 million and $277 million, respectively, in recoverable transition costs recorded in our Consolidated Balance Sheets. ComEd expects to fully recover and amortize these charges by the end of 2006, but may increase or decrease its annual amortization to maintain its earnings within the earnings cap provisions established by Illinois legislation. See Note 5 of the Notes to Consolidated Financial Statements for discussion of recoverable transition cost amortization.

- Recoverable Deferred Income Taxes: These costs represent the difference between the method in which the regulator allows for the recovery of income taxes and how income taxes would be recorded by unregulated entities. These recoverable deferred income taxes, recorded in compliance with SFAS No. 109 "Accounting for Income Taxes," include the deferred tax effects associated principally with liberalized depreciation accounted for in accordance with the ratemaking policies of the ICC and PUC, as well as the revenue impacts thereon, and assume continued recovery of these costs in future rates. At December 31, 2002 and 2001, we had $661 million and $701 million, respectively, in recoverable deferred income taxes recorded in our Consolidated Balance Sheets.

o Nuclear Decommissioning Costs for Retired Plants: These costs represent the amount of future nuclear decommissioning costs related to the retired former ComEd plants which are being recovered through rates. At December 31, 2002 and 2001, we had $248 million and $310 million, respectively, in nuclear decommissioning costs for retired plants recorded in our Consolidated Balance Sheets. These costs will be recovered in rates and amortized on a straight-line basis to earnings by the end of 2006.

For each regulatory jurisdiction where we conduct business, we continually assess whether the regulatory assets continue to meet the criteria for probable future recovery. 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. If future recovery of costs ceases to be probable, the assets and liabilities would be recognized in current period earnings. A write-off of regulatory assets could impact our ability to pay dividends under PUHCA.

Because our current rates include the recovery of existing regulatory assets and liabilities, and rates in effect during the rate freeze or rate cap periods are expected to allow us 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 in the states where we do business, but is subject to change in the future.

Nuclear Decommissioning

We currently have direct ownership interests in 16 active nuclear generating units and four retired nuclear generating units. In addition, we own a 50% equity interest in AmerGen, which operates three active nuclear generating units.

In connection with the operation of our nuclear units, the NRC requires us to decommission these facilities after their NRC operating license lives end, generally 40 years from the date of initial operation. We have, however, requested or are in the process of requesting the extension of these license lives for several nuclear generating stations. The decommissioning of a nuclear generating station involves the decontamination of structures and components, the removal of high-level and low-level radioactive materials from the site for disposal at a licensed facility and for certain stations, the restoration of the station sites to a natural state. We estimate that, once started, decommissioning of a site can generally be completed in 10 years. Based on the projected extended license lives of our nuclear plants, we will begin decommissioning our plants from 2014 through 2056, with expenditures primarily occurring when our operating plants are decommissioned, during the period from 2029 through 2056.

We currently recover certain decommissioning costs in regulated rates. The amounts recovered are deposited in trust accounts and invested for funding of future decommissioning costs for active and inactive generating units. As part of our 2001 restructuring, the generation-related assets and liabilities of ComEd and PECO were transferred to Generation. The accounting for our receipt of decommissioning collections and recognition of decommissioning liabilities varies between the plants that were previously owned by ComEd or by PECO prior to restructuring.

We account for the current period's cost of decommissioning related to generating plants previously owned by PECO by following regulatory accounting principles and recording a charge to depreciation expense and a corresponding liability in accumulated depreciation concurrent with decommissioning collections from rate payers. Our regulatory accounting principles for the generating stations previously owned by ComEd were discontinued when those stations were transferred to Generation. Those stations included both operating and retired units. For operating units, the difference between the current cost decommissioning estimate and the decommissioning liability recorded in accumulated depreciation is amortized to depreciation expense on a straight-line basis over the remaining lives. For retired units, the current cost decommissioning estimate is recorded in deferred credits and other liabilities and accreted to depreciation expense.

Under regulatory accounting principles, gains and losses on marketable securities held in the nuclear decommissioning trust funds are reported in accumulated depreciation. After regulatory accounting principles are discontinued, unrealized gains and losses on marketable securities held in the nuclear decommissioning trust funds are reported in accumulated other comprehensive income. Realized gains and losses on decommissioning trust funds are reflected in other income and deductions in our Consolidated Statements of Income. Due to the sharp declines in the equity market since the third quarter of 2000, the value of our nuclear decommissioning trust funds has also decreased. In 2002, contributions to these trust funds of $112 million were offset by net realized and unrealized losses of $224 million, resulting in a 4% decrease in the trust funds' balance at December 31, 2002 compared to December 31, 2001. We believe that the amounts that ComEd and PECO are recovering from customers through electric rates, along with the earnings on the trust funds, will be sufficient to fund our decommissioning obligations.

Cost estimates for decommissioning our nuclear facilities have been prepared by an independent engineering firm and reflect currently existing regulatory requirements and available technology. Our current estimate of our nuclear facilities' decommissioning cost is $7.4 billion in current year (2003) dollars. Calculating this estimate involves significant assumptions about the expected increases in decommissioning costs relative to general inflation rates, changes in the regulatory environment or regulatory requirements, and the timing of decommissioning. Significant changes in these assumptions could materially affect the liabilities and future costs related to decommissioning recorded in our Consolidated Financial Statements.

The estimated service life of the nuclear station is also a significant assumption because decommissioning and depreciation costs are generally recognized over the life of the generating station. In 2001, we extended nuclear station service lives, over which the decommissioning costs are recognized, by 20 years. Effective April 1, 2001, we extended the estimated service lives by 20 years for three nuclear stations. Effective July 1, 2001, we extended the estimated service lives by 20 years for the remainder of Exelon's operating nuclear stations. These changes were based on engineering and economic feasibility studies we performed considering, among other things, future capital and maintenance expenditures at these plants. The service life extension is subject to NRC approval of an extension of existing NRC operating licenses. As a result of the change, net income for 2002 and 2001 increased approximately $132 million ($79 million, net of income taxes) and approximately $90 million ($54 million, net income taxes), respectively. Although we consider the service life extension authorization to be probable, if the extensions were denied, our results of operations would be adversely impacted by increased depreciation rates and accelerated future decommissioning payments.

SFAS No. 143. The accounting for our nuclear decommissioning obligation will be affected by the adoption of SFAS No. 143, "Asset Retirement Obligations" (SFAS No. 143) effective January 1, 2003. SFAS No. 143 provides accounting requirements for retirement obligations associated with tangible long-lived assets. Retirement obligations associated with long-lived assets included within the scope of SFAS No. 143 are those for which there is a legal obligation under existing or enacted law, statute, written or oral contract or by legal construction under the doctrine of promissory estoppel.

The effect of this cumulative adjustment on nuclear decommissioning will be to change the decommissioning liability to reflect the fair value of the decommissioning obligation at the balance sheet date. Additionally, SFAS No. 143 will require the recording of an asset related to the decommissioning obligation, which will be amortized over the remaining lives of the plants. The net difference, between the asset recognized and the adjustment to the decommissioning liability recorded upon adoption of SFAS No. 143, will be charged to earnings and recognized as a cumulative effect of a change in accounting principle, net of expected regulatory recovery and net of taxes. The decommissioning liability will then represent the fair value of the obligation for the future decommissioning of the plants and, as a result, accretion expense will be accrued on this liability until the obligation is satisfied.

As noted above, we currently record the obligation for decommissioning ratably over the lives of the plants. We are currently in the process of evaluating the impact of adopting SFAS No. 143 on our financial condition. Based on the current information and the credit-adjusted risk-free rate, we estimate the increase in 2003 non-cash expense to impact earnings before the cumulative effect of a change in accounting principle for the adoption of SFAS No. 143 by approximately $24 million, after income taxes. Additionally, the adoption of SFAS No. 143 is expected to result in a large, non-cash, one-time cumulative effect of a change in accounting principle gain of at least $1.5 billion, after income taxes. The $1.5 billion gain and the $24 million charge includes our share of the impact of the SFAS No. 143 adoption related to AmerGen's nuclear plants. These impacts are based on our current interpretation of SFAS No. 143 and are subject to continued refinement based on the finalization of assumptions and interpretation at the time of adopting the standard, including the determination of the credit-adjusted risk-free rate. Under SFAS No. 143, the fair value of the nuclear decommissioning obligation will continue to be adjusted on an ongoing basis as these model input factors change.

In accordance with SFAS No. 143, we used a probabilistic cash flow model with multiple scenarios in order to determine the fair value of the decommissioning obligation. SFAS No. 143 also stipulates that fair value represent the amount a third party would receive for assuming all of an entity's obligation. Key assumptions used in our determination of fair value as defined in SFAS No. 143 include:

- decommissioning cost studies prepared by a third party

    - these decommissioning studies represent a marketplace assessment of costs and the timing of retirement activities validated by comparison to current decommissioning projects and other third party estimates

- annual cost escalation studies to determine escalation factors based on inflation indices used in decommissioning cost studies for the following major categories:

    - labor,

    - equipment and materials,

    - energy,

    - other (taxes, insurance, fees, etc.), and

    - low-level radioactive waste disposal costs.

- use of probabilistic cash flow models to measure the fair value including:

    - the probability of various cost levels, and

    - the probability of various timing scenarios incorporating the factors of current license lives and life extension and the timing of DOE acceptance for disposal of our spent nuclear fuel.

Under the Nuclear Waste Policy Act of 1982 (NWPA), the U.S. Department of Energy (DOE) is responsible for the selection and development of repositories for, and the disposal of, spent nuclear fuel and high-level radioactive waste (SNF). As required by the NWPA, ComEd and PECO, each signed a contract with the DOE (Standard Contract) to provide for disposal of SNF from their respective nuclear generating stations. The NWPA and the Standard Contract 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 significantly delayed. The DOE currently estimates it will open a SNF facility in 2010. This extended delay requires us to retain possession of the SNF, thus increasing decommissioning costs including the operation and maintenance of facilities to store SNF until the DOE removes it from our sites.

The NRC regulatory guidance suggests that decommissioning cost studies be updated every five years. Most of our studies were prepared in 1995 and 1996 and are in the process of being updated. Although no significant changes in decommissioning technologies have occurred since the studies were performed, and annual cost escalation studies are performed to determine the escalation factor applied to the base year cost study, changes in these cost studies could have a material impact on the fair value of the nuclear decommissioning obligation. The final determination of the cumulative effect of a change in accounting principle is also in part a function of the credit-adjusted risk-free rate at the time of the adoption of the standard. Additionally, although over the life of the plant, the charges to earnings for the depreciation of the asset and the interest on the liability will be equal to the amounts that would have been recognized as decommissioning expense under the current accounting, the timing of those charges will change and in the near-term period subsequent to adoption, the depreciation of the asset and the interest on the liability are expected to result in an increase in expense.

Asset Impairments

Long-Lived Assets and Investments. SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets" (SFAS No. 144), establishes accounting and reporting standards for both the impairment and disposal of long-lived assets. SFAS No. 144 continues the FASB requirements that:

- an impairment loss be recognized if the carrying amount of an asset is not recoverable from its undiscounted cash flows, and

- the impairment loss be measured as the difference between the carrying amount and the fair value of the asset.

Accounting Principles Board Opinion No. 18, "The Equity Method of Accounting for Investment in Common Stock," requires that an impairment loss be recognized for an investment if the investment declines in fair value below its amortized cost basis, and this decline is judged to be other-than-temporary.

We continually monitor our investments and businesses and the markets in which these businesses operate in order to determine events that may trigger an impairment. We have tested our businesses and investments for recoverability whenever events or changes in circumstances indicate that their carrying amounts may not be recoverable. Such triggering events may include a current expectation that there is a likelihood of 50% or greater that a long-lived asset will be sold, competitors' technological advancement, accelerated distributions of public holdings at a loss, lack of achievability of financial results versus plan, limited access to capital, or the loss of a major customer, among others. The analysis of impairment for long-lived and intangible assets is subject to an undiscounted cash flow analysis that requires significant assumptions.

In 2002, we did not identify factors through our review process that indicated potential impairment of property, plant and equipment or other long-lived assets with the exception of investments at our Enterprises business unit. Enterprises wrote down $41 million of investments in 2002 when we discovered certain triggering events, such as those described above.

Goodwill. Under SFAS No. 142, goodwill is also subject to an assessment for impairment using a two-step fair value based test, the first step of which must be performed at least annually, or more frequently if events or circumstances indicate that goodwill might be impaired. The reporting units of Exelon that were determined to have had goodwill allocated to them were Energy Delivery, Exelon's infrastructure services business (InfraSource), the energy services business (Exelon Services) and the competitive retail energy sales business (Exelon Energy). All of Energy Delivery's goodwill is at ComEd. If an impairment is determined at ComEd, the amount of the impaired goodwill will be written-off and expensed at ComEd. However, under current accounting guidance, a goodwill impairment charge at ComEd may not affect Exelon's results of operations. Exelon's goodwill impairment test would include assessing the cash flows of the entire Energy Delivery business segment (a single Reporting Unit, which includes PECO, as defined under current accounting guidance), not just ComEd's cash flows.

We performed the first step of the SFAS No. 142 impairment analysis, comparing the fair value of a reporting unit to its carrying amount, including goodwill, as of January 1, 2002, upon adoption of SFAS No. 142. That first step indicated no impairment of ComEd's goodwill but showed an impairment of the goodwill recorded in Enterprises' reporting units. In performing the Step I tests as prescribed in SFAS No. 142, ComEd and Enterprises determined that discounted cash flow models would provide the most appropriate measure to determine Step I fair value. Consistent with the guidance in SFAS No. 142, ComEd and Enterprises prepared multiple scenario discounted cash flow models in order to determine the value for Step I of SFAS No. 142. These models use multiple assumptions including revenue growth rates, general expense escalation rates, allowed return on equity, a risk-adjusted discount rate and long-term earnings multiples of comparable companies. In addition to the above-noted assumptions, ComEd's model included varying assumptions regarding:

- The timing of future rate case filings to establish new rates for bundled service after the then scheduled 2004 expiration of the rate freeze period, which has subsequently been extended to 2006 by Illinois law. Rate changes were assumed to occur at various points in 2005 through 2007 in the different scenarios.

- The cash flow impact of the expiration of the rate freeze and the resolution of uncertainties regarding future commodity risk at the expiration of the current purchase power agreements, the resolution of ComEd's POLR obligation and various other risks and uncertainties.

The results of the Step I analysis for ComEd showed a weighted average probabilistic valuation of the multiple scenario discounted cash flows in excess of ComEd's book carrying amount, including goodwill, at December 31, 2001. Since the Step I calculated fair value was in excess of book value, we could conclude that ComEd's goodwill of $4.9 billion was not impaired. The results of the Step I analysis for Enterprises, however, calculated weighted average probabilistic valuations of the multiple scenario discounted cash flows of less than the book carrying value, including goodwill, of InfraSource, Exelon Services and Exelon Energy. The second step of the analysis, which compared the fair value of each of Enterprises' reporting units' goodwill to the carrying value at December 31, 2001, indicated a total goodwill impairment of $357 million ($243 million, net of income taxes and minority interest). The impairment was recorded as a cumulative effect of a change in accounting principle in the first quarter of 2002. Enterprises' goodwill balance was $76 million at December 31, 2002.

As required by SFAS No. 142, Exelon performed the annual update of ComEd's and Enterprises' goodwill impairment analyses using a November 1, 2002 measurement date. These valuations determined the Step I calculated fair value of both ComEd and the Enterprises' units to be in excess of their respective book values at November 1, 2002. Since the Step I calculated fair value was in excess of book value, we concluded that goodwill was not impaired. Again, the probabilistic discounted cash flows model used in these analyses included the significant assumptions noted above. Rate changes were assumed to occur at various points in 2007 through 2009 in the different scenarios for ComEd based on the June 2002 extension of the rate freeze.

Modifications to any of the assumptions discussed above, particularly changes in discount rates, long-term earnings multiples of comparable companies used to determine terminal values, and the expected results of rate proceedings, could result in a future impairment of goodwill. Actual results as well as market conditions in upcoming periods will impact the probabilities of scenarios used in the models. If the estimates of future cash flows in both the ComEd and Enterprises models had been 10% lower, respectively, those discounted cash flows would still have been greater than the carrying values of ComEd and Enterprises, respectively. As we were not required to perform a Step II analysis at the November 1, 2002 measurement date for either ComEd or Enterprises, a dollar amount for any potential impairment has not been determined. Because goodwill represents approximately 85% of ComEd's common equity, a potential future impairment of goodwill could significantly impact ComEd's ability to pay dividends to Exelon under PUHCA. The Illinois legislation provides that reductions to ComEd's common equity resulting from goodwill impairments will not impact ComEd's earnings cap calculation through 2006.

Defined Benefit Pension and Other Postretirement Welfare Benefits

We sponsor defined benefit pension plans and postretirement welfare benefit plans applicable to essentially all ComEd, PECO, Generation and BSC employees and certain Enterprises employees. 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, we utilize assumptions about the future, including the expected rate of return on plan assets, the discount rate applied to benefit obligations, rate of compensation increase and the anticipated rate of increase in health care costs. In accordance with SFAS No. 87, "Employers' Accounting for Pensions" (SFAS No. 87) and SFAS No. 106, "Employers' Accounting for Postretirement Benefits Other than Pensions" (SFAS No. 106) the impact of changes in these factors on pension and other postretirement welfare benefit obligations is generally recognized over the expected remaining service life of the employees rather than immediately recognized in the income statement.

In selecting the expected rate of return on plan assets, we considered historical and expected returns for the types of investments the plans hold. Our pension trust assets have lost $581 million, and $265 million, and gained $173 million in 2002, 2001 and 2000, respectively. The long-term expected rate of return on plan assets (EROA) assumption used in calculating pension cost was 9.5% at January 1, 2002, 2001 and 2000. We generally maintain 60% of our plan assets in equity securities and 40% of our plan assets in fixed-income securities. Each quarter we review the actual asset allocations and follow a rebalancing procedure in order to remain within an allowable range of these targeted percentages. Based on our asset allocation and long-term historical returns for both equity and fixed-income securities, we set our EROA at 9.0% as of January 1, 2003 in order to calculate 2003 pension cost. Our other postretirement benefit assets have lost $125 million, $14 million and $7 million in 2002, 2001 and 2000, respectively. The EROA assumption used in calculating the other postretirement benefit obligation was 8.8% at January 1, 2002, 2001 and 2000, respectively. We will use an EROA assumption of 8.4% as of January 1, 2003 in order to calculate the 2003 other postretirement benefit costs. 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.

We use the Moody's Aa Corporate Bond Index as a basis in selecting the discount rate. As described in Note 15 of the Notes to Consolidated Financial Statements, we set the assumed discount rate at 7.35% and 6.75% at December 31, 2001 and 2002, respectively, in our estimate of pension expense and other postretirement benefit costs.

The following table illustrates the effect of changing the major actuarial assumptions discussed above:

Change in Actuarial Assumption	Impact on Projected Benefit Obligation at December 31, 2002	Impact on Pension Liability at December 31, 2002	Impact on 2003 Pension Cost
Pension Benefits			
Decrease Discount Rate by 0.5%	$ 336	$ 336	$ 8
Decrease Rate of Return on Plan Assets by 0.5%	--	--	32

Change in Actuarial Assumption	Impact on Other Postretirement Benefit Obligation at December 31, 2002	Impact on Postretirement Benefit Liability at December 31, 2002	Impact on 2003 Postretirement Benefit Cost
Postretirement Benefits			
Decrease Discount Rate by 0.5%	$ 152	$ --	$ 18
Decrease Rate of Return on Plan Assets by 0.5%	--	--	6

The assumptions are reviewed at the beginning of each year during our annual review process. The impact of assumption changes are reflected in the recorded pension amounts consistent with assumption changes as they occur. As these assumptions change from period to period, recorded pension amounts and funding requirements could also change.

Our pension and other postretirement benefit plans have unrecognized losses of $2.1 billion and $0.8 billion, respectively, at December 31, 2002. This unrecognized loss primarily represents the difference between the expected return on plan assets and the actual return on plan assets that has not yet been recognized in pension or other postretirement benefit expense. We generally amortize these unrecognized (gains)/losses over five years; however, the annual amortization amounts vary based on actuarial determinations. Recognition of an unrecognized loss will result in increased net periodic pension cost going forward.

Primarily as a result of sharp declines in the equity markets since the third quarter of 2000, we recognized an additional minimum liability of $1.0 billion, net of income taxes, and an intangible asset of $211 million as prescribed by SFAS No. 87 in the fourth quarter of 2002. The liability was recorded as a reduction to shareholders' equity, and the equity will be restored to the balance sheet in future periods when the fair value of plan assets exceeds the accumulated benefit obligation. The recording of this additional minimum liability did not affect net income or cash flow in 2002 or compliance with debt covenants; however, pension cost and cash funding requirements could increase in future years without a substantial recovery in the equity markets.

Our defined benefit pension plans currently meet the minimum funding requirements of the Employment Retirement Income Security Act of 1974 without any additional funding; however, we made a discretionary tax-deductible plan contribution of $150 million in the fourth quarter of 2002 funded by ComEd, Generation and BSC. We also expect to make a discretionary tax-deductible plan contribution in 2003 of $300 million to $350 million.

Approximately $93 million was included in operating and maintenance expense in 2002 for the cost of our pension and postretirement benefit plans, exclusive of the 2002 charges for employee severance programs. Although the 2003 increase in pension and postretirement benefit cost will depend on market conditions, our estimate is that expense will increase by approximately $125 million in 2003 from 2002 expense levels as the result of the effects of the decline in market value of plan assets in 2002, the decline in discount rate and increases in health care costs.

In 2001, we adopted a cash balance pension plan. All management and electing union employees who were hired by us after 2001 became participants in the plan. Approximately 4,700 management employees who were active participants in our previous qualified defined benefit plans at December 31, 2000 and remained employed by us on January 1, 2002 elected to transfer to the cash balance plan. Participants in the cash balance plan, unlike participants in the other defined benefit plans, may request a lump-sum cash payment upon employee termination. This may result in increased cash requirements from pension plan assets, which may increase future funding to the pension plan.

Stock-Based Compensation Plans

We maintain a Long-Term Incentive Plan (LTIP) for certain full-time salaried employees and previously maintained a broad-based incentive program for certain other employees. The types of long-term incentive awards that have been granted under the LTIP are non-qualified options to purchase shares of our common stock and common stock awards. 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 LTIP and the broad-based incentive program become exercisable upon attainment of a target share value and/or time. All options expire 10 years from the date of grant.

At December 31, 2002, there were 13,000,000 options authorized for issuance under the LTIP and 2,000,000 options authorized under the broad-based incentive program. We currently follow the disclosure-only provisions of SFAS No. 123, "Accounting for Stock-Based Compensation" (SFAS No. 123). If we elected to account for our stock-based compensation plans based on SFAS No. 123, we would have recognized compensation expense of $33 million, $26 million and $25 million, for 2002, 2001 and 2000, respectively.

We use an independent actuarial firm to calculate the fair value of the options and to assist in the development of amounts required to be disclosed under SFAS No. 123. The key assumptions used in this determination of fair value are the expected volatility of the stock price, based on historical information; the expected life of the options, based on the vesting period and expiration date of the options; the estimated dividend yield, based on historical information adjusted for material known future changes; and the risk-free interest rate, based on the yield of a United States Treasury Strip available on the date of the grant and expiring at the approximate end of the option's term. Changes in these assumptions could have resulted in material changes in the amounts disclosed under SFAS No. 123 in Notes 1 and 17 of the Notes to Consolidated Financial Statements.

Business Combinations

In the three year period ended December 31, 2002, we have completed several business combinations and asset acquisitions. We adopted SFAS No. 141 as of January 1, 2002. SFAS No. 141 is effective for business combinations initiated after June 30, 2001. SFAS No. 141 requires that all business combinations be accounted for under the purchase method of accounting and establishes criteria for the separate recognition of intangible assets acquired in business combinations. Under the purchase method of accounting, purchased assets and liabilities must be recorded at their fair value. If a quoted fair value is not readily available for the majority of assets and liabilities exchanged, the determination of this fair value requires the use of significant judgment, both by management and outside experts engaged to assist in this determination process. Changes in the assumptions made in determining the fair values could have resulted in material changes in the amounts disclosed in Note 3 of the Notes to Consolidated Financial Statements. There would also be an impact on our financial results. If the fair value of property, plant and equipment acquired in a business combination would have been higher, and an amount allocated to goodwill in the business combination lower, depreciation expense would have been higher. Conversely, if the fair value of property, plant and equipment acquired in a business combination would have been lower, and an amount allocated to goodwill in the business combination higher, depreciation expense would have been lower. For example, if the $2 billion fair value of the generating plants acquired in the Merger was estimated to be 1% higher, then annual depreciation expense would be less than $1 million higher and goodwill amortization, which ceased in 2002, would have been less than $1 million lower annually.

Unbilled Energy Revenues

Revenues related to the sale of energy are generally recorded when service is rendered or energy is delivered to customers. The determination of the 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 during the month 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 demand measured by generation volume, estimated customer usage by class, estimated losses of energy during delivery to customers (line loss) and applicable customer rates. Customer accounts receivable as of December 31, 2002 include unbilled energy revenues of $442 million. Increases in volumes delivered to the utilities' customers in the period would increase 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.

Long-Term Contract Accounting

Enterprises recognizes contract revenue and profits on certain long-term fixed-price contracts by the percentage-of-completion method of accounting. As contract work is completed, the corresponding percentage of total estimated profit on the contract is recognized in the Consolidated Statements of Income. In determining the amount of revenue to recognize, we are required to estimate, at the beginning of the contract, the total costs and profits expected to be recorded under the contract over its contract term, and, on an on-going basis, the recoverability of costs related to change orders. Changes in these estimates could result in the recognition of differences in earnings. At December 31, 2002, Current Assets included $70 million of costs and earnings in excess of billings on uncompleted contracts and Current Liabilities included $44 million of billings and earnings in excess of costs on uncompleted contracts.

Environmental Costs

As of December 31, 2002, we had accrued liabilities of $156 million for environmental investigation and remediation costs. These liabilities are based upon estimates with respect to the number of sites for which we 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 $97 million of the accrued liabilities total above. Where timing and amounts cannot be reliably estimated, amounts are recognized on an undiscounted basis. Such amounts represent $59 million of the accrued liabilities total above. Estimates can be affected by the factors noted above as well as by changes in technology and changes in regulations or the requirements of local governmental authorities.

Quantitative and Qualitative Disclosures About Market Risk

We are exposed to market risks associated with commodity prices, credit, interest rates and equity prices. The inherent risk in market sensitive instruments and positions is the potential loss arising from adverse changes in commodity prices, counterparty credit, interest rates and equity security prices. Our RMC sets forth risk management philosophy and objectives and establishes procedures 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 and officers from each of the business units. The RMC reports to the board of directors on the scope of our derivative activities.

Commodity Price Risk

Commodity price risk is associated with market price movements resulting from excess or insufficient generation, changes in fuel costs, market liquidity and other factors. Trading activities and non-trading marketing activities include the purchase and sale of electric capacity and energy and fossil fuels, including oil, gas, coal and emission allowances. The availability and prices of energy and energy-related commodities are subject to fluctuations due to factors such as weather, governmental environmental policies, changes in supply and demand, state and federal regulatory policies and other events.

Normal Operations and Hedging Activities. Electricity available from our owned or contracted generation supply in excess of our obligations to customers, including Energy Delivery's retail load, is sold into the wholesale markets. To reduce price risk caused by market fluctuations, we enter into physical contracts as well as derivative contracts, including forwards, futures, swaps, and options, with approved counterparties to hedge our anticipated exposures. The maximum length of time over which cash flows related to energy commodities are currently being hedged is 4 years. We have an estimated 90% hedge ratio in 2003 for our energy marketing portfolio. This hedge ratio represents the percentage of our forecasted aggregate annual generation supply that is committed to firm sales, including sales to Energy Delivery's retail load. The hedge ratio is not fixed and will vary from time to time depending upon market conditions, demand and volatility and during peak periods our amount hedged declines to meet our commitment to Energy Delivery. Market price risk exposure is the risk of a change in the value of unhedged positions. Absent any opportunistic efforts to mitigate market price exposure, the estimated market price exposure for our non-trading portfolio associated with a ten percent reduction in the annual average around-the-clock market price of electricity is an approximately $37 million decrease in net income, or approximately $0.11 per share. This sensitivity assumes a 90% hedge ratio and that price changes occur evenly throughout the year and across all markets. The sensitivity also assumes a static portfolio. We expect to actively manage our 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 our portfolio.

Proprietary Trading Activities. We began to use financial contracts for proprietary trading purposes in the second quarter of 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 our energy marketing portfolio and represent a very small portion of our overall energy marketing activities. For example, the limit on open positions in electricity for any forward month represents less than 1% of our owned and contracted supply of electricity. The trading portfolio is subject to stringent risk management limits and policies, including volume, stop-loss and value-at-risk limits.

Our energy contracts are accounted for under SFAS No. 133. Most non-trading contracts qualify for the normal purchases and normal sales exemption to SFAS No. 133 discussed in Critical Accounting Estimates. Those that do not 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 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 hedge criteria under SFAS No. 133 and the ineffective portion of hedge contracts are recognized in earnings on a current basis.

The following detailed presentation of our trading and non-trading marketing activities at Generation is included to address the recommended disclosures by the energy industry's Committee of Chief Risk Officers. We do not consider our proprietary trading to be a significant activity in our business; however, we believe it is important to include these risk management disclosures.

The following table describes the drivers of our energy trading and marketing business and gross margin included in the income statement for the year ended December 31, 2002. Normal operations and hedging activities represent the marketing of electricity available from Generation's owned or contracted generation, including Energy Delivery's retail load, sold into the wholesale market. As the information in this table highlights, mark-to-market activities represent a small portion of the overall gross margin for Generation. Accrual activities, including normal purchases and sales, account for the majority of the gross margin. The mark-to-market activities reported here are those relating to changes in fair value due to external movement in prices. Further delineation of gross margin by the type of accounting treatment typically afforded each type of activity is also presented (i.e., mark-to-market vs. accrual accounting treatment).

	Normal Operations and Hedging Activities (a)	Proprietary Trading	Total
Mark-to-Market Activities:			
Unrealized Mark-to-Market Gain/(Loss)			
Origination Unrealized Gain/(Loss) at Inception	$ --	$ --	$ --
Changes in Fair Value Prior to Settlements	26	(29)	(3)
Changes in Valuation Techniques and Assumptions	--	--	--
Reclassification to Realized at Settlement of Contracts	(20)	20	--
Total Change in Unrealized Fair Value	6	(9)	(3)
Realized Net Settlement of Transactions Subject to Mark-to-Market	20	(20)	--
Total Mark-to-Market Activities Gross Margin	$ 26	$ (29)	$ (3)
Accrual Activities:			
Accrual Activities Revenue	$ 6,785	$ --	$ 6,785
Hedge Gains/(Losses) Reclassified from OCI	76	--	76
Total Revenue - Accrual Activities	6,861	--	6,861
Fuel and Purchased Power	4,230	--	4,230
Hedges of Fuel and Purchased Power Reclassified from OCI	23	--	23
Total Fuel and Purchased Power	4,253	--	4,253
Total Accrual Activities Gross Margin	2,608	--	2,608
Total Gross Margin	$ 2,634	$ (29)	$ 2,605 (b)

(a) Normal Operations and Hedging Activities only include derivative contracts Power Team enters into to hedge anticipated exposures related to our owned and contracted generation supply, but excludes our owned and contracted generating assets as well as Enterprises' derivative contracts.
(b) Total Gross Margin represents revenue, net of purchased power and fuel

expense for Generation. This excludes a minimal amount of activity at Enterprises. See Note 18 of the Notes to Consolidated Financial Statements for further information.

The following table provides detail on changes in Generation's mark-to-market net asset or liability balance sheet position from January 1, 2002 to December 31, 2002. It indicates the drivers behind changes in the balance sheet amounts. This table will incorporate the mark-to-market activities that are immediately recorded in earnings, as shown in the previous table, as well as the settlements from OCI to earnings and changes in fair value for the hedging activities that are recorded in Accumulated Other Comprehensive Income on the Consolidated Balance Sheets.

	Normal Operations and Hedging Activities	Proprietary Trading	Total
Total Mark-to-Market Energy Contract Net Assets at January 1, 2002	$ 78	$ 14	$ 92
Total Change in Fair Value during 2002 of Contracts Recorded in Earnings	26	(29)	(3)
Reclassification to Realized at Settlement of Contracts Recorded in Earnings	(20)	20	--
Reclassification to Realized at Settlement from OCI	(53)	--	(53)
Effective Portion of Changes in Fair Value - Recorded in OCI	(210)	--	(210)
Purchase/Sale of Existing Contracts or Portfolios Subject to Mark-to-Market	11	--	11
Total Mark-to-Market Energy Contract Net Assets (Liabilities) at December 31, 2002	$ (168)	$ 5	$ (163)

The following table details the balance sheet classification of the Mark-to-Market Energy Contract Net Assets recorded as of December 31, 2002:

	Normal Operations and Hedging Activities	Proprietary Trading	Total
Current Assets	$ 186	$ 6	$ 192
Noncurrent Assets	46	--	46
Total Mark-to-Market Energy Contract Assets	232	6	238
Current Liabilities	(276)	--	(276)
Noncurrent Liabilities	(124)	(1)	(125)
Total Mark-to-Market Energy Contract Liabilities	(400)	(1)	(401)
Total Mark-to-Market Energy Contract Net Assets (Liabilities)	$ (168)	$ 5	$ (163)

The majority of our 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 midpoint prices obtained from all sources that we believe provide the most liquid market for the commodity. The terms for which such price information is available varies by commodity, by region and by 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, 2002 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 assets, 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 generate or require cash.

	Maturities within						
	2003	2004	2005	2006	2007	2008 and Beyond	Total Fair Value
Normal Operations, qualifying cash flow hedge contracts (1):							
Prices provided by other external sources	$(124)	$ (48)	$ (9)	$ (5)	$ --	$ --	$ (186)
Total	$(124)	$ (48)	$ (9)	$ (5)	$ --	$ --	$ (186)
Normal Operations, other derivative contracts (2):							
Actively quoted prices	$ 26	$ 4	$ --	$ --	$ --	$ --	$ 30
Prices provided by other external sources	--	3	2	2	--	--	7
Prices based on model or other valuation methods	7	(11)	(4)	(9)	(2)	--	(19)
Total	$ 33	$ (4)	$ (2)	$ (7)	$ (2)	$ --	$ 18
Proprietary Trading, other derivative contracts (3):							
Actively quoted prices	$ (4)	$ --	$ --	$ --	$ --	$ --	$ (4)
Prices provided by other external sources	6	(3)	--	--	--	--	3
Prices based on model or other valuation methods	5	1	--	--	--	--	6
Total	$ 7	$ (2)	$ --	$ --	$ --	$ --	$ 5
Average tenor of proprietary trading portfolio (4)							1.5 years

(1) Mark-to-market gains and losses on contracts that qualify as cash flow hedges are recorded in other comprehensive income.
(2) Mark-to-market gains and losses on other non-trading derivative contracts that do not qualify as cash flow hedges are recorded in earnings.
(3) Mark-to-market gains and losses on trading contracts are recorded in earnings.
(4) Following the recommendations of the Committee of Chief Risk Officers, the average tenor of the proprietary trading portfolio measures the average time to collect value for that portfolio. We measure the tenor by separating positive and negative mark-to-market values in its proprietary trading portfolio, estimating the mid-point in years for each and then reporting the highest of the two mid-points calculated. In the event that this methodology resulted in significantly different absolute values of the positive and negative cash flow streams, we would use the mid-point of the portfolio with the largest cash flow stream as the tenor.

The table below provides details of effective cash flow hedges under SFAS No. 133 included in the balance sheet as of December 31, 2002. The data in the table gives an indication of the magnitude of SFAS No. 133 hedges we have in place, however, given that under SFAS No. 133 not all hedges are recorded in OCI, the table does not provide an all-encompassing picture of our hedges. The table also includes a roll-forward of Accumulated Other Comprehensive Income related to cash flow hedges for the year ended December 31, 2002, 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 Other Comprehensive Income Activity, Net of Income Tax		
	Power Team Normal Operations and Hedging Activities	Interest Rate and Other Hedges (1)	Total Cash Flow Hedges
Accumulated OCI, January 1, 2002	$ 47	$ (25)	$ 22
Changes in Fair Value	(128)	(51)	(179)
Reclassifications from OCI to Net Income	(33)	(9)	(42)
Accumulated OCI Derivative Gain/(Loss) at December 31, 2002	$ (114)	$ (85)	$ (199)

(1) Includes interest rate hedges at Generation, ComEd and PECO, as well as energy commodity hedges at Enterprises.

We use a Value-at-Risk (VaR) model to assess the market risk associated with financial derivative instruments entered into for proprietary trading purposes. The measured VaR represents an estimate of the potential change in value of our proprietary trading portfolio.

The VaR estimate includes a number of assumptions about current market prices, estimates of volatility and correlations between market factors. These estimates, however, are not necessarily indicative of actual results, which may differ because actual market rate fluctuations may differ from forecasted fluctuations and because the portfolio may change over the holding period.

We estimate VaR using a model based on the Monte Carlo simulation of commodity prices that captures the change in value of forward purchases and sales as well as option values. Parameters and values are backtested daily against daily changes in mark-to-market value for proprietary trading activity. Value-at-Risk assumes that normal market conditions prevail and that there are no changes in positions. We use a 95% confidence interval, one-day holding period, one-tailed statistical measure in calculating our VaR. This means that we may state that there is a one in 20 chance that if prices move against our portfolio positions, our pre-tax loss in liquidating our portfolio in a one-day holding period would exceed the calculated VaR. To account for unusual events and loss of liquidity, we use stress tests and scenario analysis.

For financial reporting purposes only, we calculate several other VaR estimates. The higher the confidence interval, the less likely the chance that the VaR estimate would be exceeded. A longer holding period considers the effect of liquidity in being able to actually liquidate the portfolio. A two-tailed test considers potential upside in the portfolio in addition to the potential downside in the portfolio considered in the one-tailed test. The following table provides the VaR for all proprietary trading positions of Generation as of December 31, 2002.

	Proprietary Trading VaR
95% Confidence Level, One-Day Holding Period, One-Tailed	
Period End	$ 0.2
Average for the Period	1.4
High	5.0
Low	0.2
95% Confidence Level, Ten-Day Holding Period, Two-Tailed	
Period End	$ 0.3
Average for the Period	1.5
High	5.3
Low	0.1
99% Confidence Level, One-Day Holding Period, Two-Tailed	
Period End	$ 0.9
Average for the Period	4.6
High	16.7
Low	0.4

Credit Risk

Credit risk for Energy Delivery is managed by each of ComEd's and PECO's 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, 2002, ComEd's ten largest customers represented approximately 3% of its retail electric revenues and PECO's ten largest customers represented approximately 8% of its retail electric revenues. We 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.

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 table provides information on Generation's credit exposure, net of collateral, as of December 31, 2002. It further delineates that exposure by the credit rating of the counterparties and provides 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 table below do not include sales to Generation's affiliates or exposure through Independent System Operators (ISOs) which are discussed below.

Rating	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	$ 156	$ --	$ 156	2	$ 71
Split Rating	--	--	--	--	--
Non-Investment Grade	17	11	6	--	--
No External Ratings					
Internally Rated - Investment Grade	27	4	23	4	16
Internally Rated - Non-Investment Grade	4	2	2	--	--
Total	$ 204	$ 17	$ 187	6	$ 87

Rating			Maturity of Credit Risk Exposure	
	Less than 2 Years	2-5 Years	Exposure Greater than 5 Years	Total Exposure Before Credit Collateral
Investment Grade	$ 117	$ 39	$ --	$ 156
Split Rating	--	--	--	--
Non-Investment Grade	17	--	--	17
No External Ratings				
Internally Rated - Investment Grade	27	--	--	27
Internally Rated - Non-Investment Grade	4	--	--	4
Total	$ 165	$ 39	$ --	$ 204

Generation is a counterparty to Dynegy in various energy transactions. In early July 2002, the credit ratings of Dynegy were downgraded to below investment grade by two credit rating agencies. As of December 31, 2002, Generation had a net receivable from Dynegy of approximately $3 million and, consistent with the terms of the existing credit arrangement, has received collateral in support of this receivable. Generation also has credit risk associated with Dynegy through Generation's equity investment in Sithe. Sithe is a 60% owner of the Independence generating station, a 1,040-MW gas-fired qualified facility that has an energy-only long-term tolling agreement with Dynegy, with a related financial swap arrangement. As of December 31, 2002, Sithe had recognized an asset on its balance sheet related to the fair market value of the financial swap agreement with Dynegy that is marked-to-market under the terms of SFAS No. 133. If Dynegy is unable to fulfill the terms of this agreement, Sithe would be required to impair this financial swap asset. We estimate, as a 49.9% owner of Sithe, that the impairment would result in an after-tax reduction of our equity earnings of approximately $10 million.

In addition to the impairment of the financial swap asset, if Dynegy were unable to fulfill its obligations under the financial swap agreement and the tolling agreement, we would likely incur a further impairment associated with the Independence plant. Depending upon the timing of Dynegy's failure to fulfill its obligations and the outcome of any restructuring initiatives, we could realize an after-tax charge of between $0 and $130 million. In the event of a sale of our investment in Sithe to a third party, proceeds from the sale could be negatively impacted by approximately $100 million, or approximately $65 million net of income taxes.

Additionally, the future economic value of AmerGen's purchased power arrangement with Illinois Power Company, a subsidiary of Dynegy, could be impacted by events related to Dynegy's financial condition.

Generation participates in the following established, real-time energy markets, which are administered by ISOs: PJM, New England ISO, New York ISO, California ISO, Midwest ISO, Inc., Southwest Power Pool, Inc. and Texas, which is administered by 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 our financial condition, results of operations or net cash flows.

Our consolidated balance sheet includes a $445 million net investment in a direct financing lease as of December 31, 2002. The investment in direct financing leases represents future minimum lease payments due at the end of the thirty-year life of the lease of $1,492 million, less unearned income of $1,047 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 our counterparties to this direct financing lease.

Interest Rate Risk

We use a combination of fixed rate and variable rate debt to reduce interest rate exposure. We also use interest rate swaps when deemed appropriate to adjust exposure based upon market conditions. Additionally, we use forward-starting interest rate swaps and treasury rate locks to lock in interest rate levels in anticipation of future financing. These strategies are employed to achieve a lower cost of capital. As of December 31, 2002, a hypothetical 10% increase in the interest rates associated with variable rate debt would result in a $5 million decrease in pre-tax earnings for 2003.

We have entered into fixed to floating interest rate swaps in order to maintain our targeted percentage of variable rate debt, associated with ComEd's debt issuances in the aggregate amount of $485 million. At December 31, 2002, these interest rate swaps, designated as fair value hedges, had a fair market value of $41 million based on the present value difference between the contract and market rates at December 31, 2002. If we had not had the fair value hedges in place at ComEd, we would have recognized an additional $14 million in interest expense in 2002.

During 2002 and 2001, ComEd entered into forward-starting interest rate swaps, with an aggregate notional amount of $830 million and $250 million, respectively, in anticipation of the issuance of debt. In connection with bond issuances in 2002, ComEd settled forward-starting interest rate swaps in the aggregate notional amount of $450 million, resulting in a $10 million pre-tax loss recorded as a regulatory asset, which is being amortized over the life of the related debt in interest expense. At December 31, 2002, ComEd had $630 million of forward-starting interest rate swaps outstanding. These interest rate swaps, designated as cash flow hedges, had a fair market value exposure of $52 million at December 31, 2002. As it remained probable that the debt issuances, the forecasted future transactions these swaps were hedging, would occur, although the issuances had been delayed, we continued to account for these interest rate swap transactions as hedges. In connection with ComEd's January 22, 2003 issuance of $700 million in First Mortgage Bonds, we settled swaps, in the aggregate notional amount of $550 million, for a payment of $43 million, which will be recorded as a regulatory asset and amortized over the life of the debt issuance.

During 2002, PECO entered into forward-starting interest rate swaps, with an aggregate notional amount of $200 million, in anticipation of the issuance of debt at PECO. These interest rate swaps were designated as cash flow hedges. In connection with bond issuances in 2002, PECO settled these forward-starting interest rate swaps resulting in a $5 million pre-tax loss recorded in OCI, which is being amortized over the life of the related debt.

PECO also had entered into interest rate swaps to manage interest rate exposure associated with the floating rate series of transition bonds issued to securitize PECO's stranded cost recovery. At December 31, 2002, these interest rate swaps had an aggregate fair market value exposure of $22 million.

PECO also has interest rate swaps in place to satisfy counterparty credit requirements in regards to the floating rate series of transition bonds which are mirror swaps of each other. These swaps are not designated as cash flow hedges, therefore, they are required to be marked-to-market if there is a difference in their values. Since these swaps are offsetting each other, a mark-to-market adjustment is not expected to occur.

Under the terms of the Sithe Boston Generation, LLC (SBG) project debt facility, SBG is required to effectively fix the interest rate on 50% of borrowings under the facility through its maturity in 2007. As of December 31, 2002, we have entered into interest rate swap agreements which have effectively fixed the interest rate on $861 million of notional principal, or 83% of borrowings outstanding at December 31, 2002. The fair market value exposure of these swaps, designated as cash flow hedges, is $92 million.

The aggregate fair value of our 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, 2002 is estimated to be $49 million. If the derivative instruments had been terminated at December 31, 2002, this estimated fair value represents the amount the counterparties would pay us.

The aggregate fair value of our 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, 2002 is estimated to be $33 million. If the derivative instruments had been terminated at December 31, 2002, this estimated fair value represents the amount the counterparties would pay us.

The aggregate fair value exposure of our interest rate swaps designated as cash flow hedges that would have resulted from a hypothetical 50 basis point decrease in the spot yield at December 31, 2002 is estimated to be $200 million. If the derivative instruments had been terminated at December 31, 2002, this estimated fair value represents the amount we would pay to the counterparties.

The aggregate fair value exposure of our interest rate swaps designated as cash flow hedges that would have resulted from a hypothetical 50 basis point increase in the spot yield at December 31, 2002 is estimated to be $132 million. If the derivative instruments had been terminated at December 31, 2002, this estimated fair value represents the amount we would pay to the counterparties.

Equity Price Risk

We maintain trust funds, as required by the NRC, to fund certain costs of decommissioning our nuclear plants. As of December 31, 2002, our decommissioning trust funds are reflected at fair value on our 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 us 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. We actively monitor the investment performance of the trust funds and periodically review asset allocation in accordance with our nuclear decommissioning trust fund investment policy. A hypothetical 10% increase in interest rates and decrease in equity prices would result in a $172 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.

New Accounting Pronouncements

In 2001, the FASB issued SFAS No. 143. SFAS No. 143 provides accounting requirements for retirement obligations associated with tangible long-lived assets. We will adopt SFAS No. 143 on January 1, 2003. Retirement obligations associated with long-lived assets included within the scope of SFAS No. 143 are those for which there is a legal obligation to settle under existing or enacted law, statute, written or oral contract or by legal construction under the doctrine of promissory estoppel. Adoption of SFAS No. 143 will change the accounting for the decommissioning of our nuclear generating plants as well as certain other long-lived assets. We are in the process of evaluating the impact of adopting SFAS No. 143 on our financial condition.

As it relates to nuclear decommissioning, the effect of a cumulative adjustment will be to decrease the decommissioning liability to reflect the fair value of the decommissioning obligation at the balance sheet date. Additionally, SFAS No. 143 will require the recognition of an asset related to the decommissioning obligation, which will be amortized over the remaining lives of the plants. The net difference, between the asset recognized and the change in the liability to reflect fair value recorded upon adoption of SFAS No. 143, will be recorded in earnings and recognized as a cumulative effect of a change in accounting principle, net of expected regulatory recovery and income taxes. The decommissioning liability will then represent an obligation for the future decommissioning of the plants and, as a result, accretion expense will be accrued on this liability until the obligation is satisfied.

Currently, Generation records the obligation for decommissioning ratably over the lives of the plants. Based on the current information and the credit-adjusted risk-free rate, we estimate the increase in 2003 non-cash expense to impact earnings before the cumulative effect of a change in accounting principle for the adoption of SFAS No. 143 by approximately $24 million, after income taxes. Additionally, the adoption of SFAS No. 143 is expected to result in a large, non-cash, one-time cumulative effect of a change in accounting principle gain of at least $1.5 billion, after income taxes. The $1.5 billion gain and the $24 million charge includes our share of the impact of the SFAS No. 143 adoption related to AmerGen's nuclear plants. These impacts are based on our current interpretation of SFAS No. 143 and are subject to continued refinement based on the finalization of assumptions and interpretation at the time of adopting the standard, including the determination of the credit-adjusted risk-free rate. Under SFAS No. 143, the fair value of the nuclear decommissioning obligation will continue to be adjusted on an ongoing basis as these model input factors change.

The final determination of the 2003 earnings impact and the cumulative effect of adopting SFAS No. 143 is in part a function of the credit adjusted risk-free rate at the time of the adoption of SFAS No. 143. Additionally, although over the life of the plant the charges to earnings for the depreciation of the asset and the interest on the liability will be equal to the amounts that would have been recognized as decommissioning expense under current accounting, the timing of those charges will change and in the near-term period subsequent to adoption, the depreciation of the asset and the interest on the liability is expected to result in an increase in expense.

In July 2002, the FASB issued SFAS No. 146, "Accounting for Costs Associated with Exit or Disposal Activities" (SFAS No. 146). SFAS No. 146 requires that the liability for costs associated with exit or disposal activities be recognized when incurred, rather than at the date of a commitment to an exit or disposal plan. SFAS No. 146 is to be applied prospectively to exit or disposal activities initiated after December 31, 2002.

In November 2002, the FASB released FASB Interpretation No. (FIN) 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others" (FIN No. 45), providing for expanded disclosures and recognition of a liability for the fair value of the obligation undertaken by the guarantor. Under FIN No. 45, guarantors are required to disclose the nature of the guarantee, the maximum amount of potential future payments, the carrying amount of the liability and the nature and amount of recourse provisions or available collateral that would be recoverable by the guarantor. As of December 31, 2002, we have adopted disclosure requirements under FIN No. 45, which were effective for financial statements for periods ended after December 15, 2002. The recognition and measurement provisions of FIN No. 45 are effective, on a prospective basis, for guarantees issued or modified after December 31, 2002.

In January 2003, the FASB issued FIN No. 46, "Consolidation of Variable Interest Entities" (FIN No. 46). FIN No. 46 addresses consolidating certain variable interest entities and applies immediately to variable interest entities created after January 31, 2003. The impact, if any, of adopting FIN 46 on our consolidated financial position, results of operations and cash flows, has not been fully determined.

Forward-Looking Statements

Except for the historical information contained in this report, certain of the matters discussed in this Report are forward-looking statements that are subject to risks and uncertainties. The factors that could cause actual results to differ materially include those we have discussed in this report as well as those listed in Note 19 of the Notes to Consolidated Financial Statements and other factors discussed in our filings with the SEC. Readers should not place undue reliance on these forward-looking statements, which speak only as of the date of this Report. We undertake no obligation to publicly release any revision to these forward-looking statements to reflect events or circumstances after the date of this Report.

Exhibit 99-4

Exelon Corporation and Subsidiary Companies Financial Statements and Supplementary Data

Report of Independent Accountants

To the Shareholders and
Board of Directors of
Exelon Corporation:

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, cash flows and changes in shareholders' equity and comprehensive income present fairly, in all material respects, the financial position of Exelon Corporation and Subsidiary Companies (Exelon) at December 31, 2002 and December 31, 2001, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2002 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of Exelon'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 auditing standards generally accepted in the United States of America, which require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 2 to the consolidated financial statements, Exelon acquired Unicom Corporation on October 20, 2000 in a business combination accounted for under the purchase method of accounting. The results of Unicom Corporation are included in the consolidated financial statements since the acquisition date.

As discussed in Note 4 to the consolidated financial statements, Exelon changed its method of accounting for nuclear outage costs in 2000.

As discussed in Note 1 to the consolidated financial statements, Exelon changed its method of accounting for derivative instruments and hedging activities effective January 1, 2001.

As discussed in Note 4 to the consolidated financial statements, Exelon changed its method of accounting for goodwill effective January 1, 2002.

Chicago, Illinois

January 29, 2003, except for Note 23 for which the date is February 20, 2003.

Exelon Corporation and Subsidiary Companies
Consolidated Statements of Income

	For the Years Ended December 31,		
in millions, except per share data	2002	2001	2000
Operating Revenues	$ 14,955	$ 14,918	$ 7,499
Operating Expenses			
Purchased Power	3,262	3,156	1,620
Purchased Power from Unconsolidated Affiliate	273	57	52
Fuel	1,727	1,877	934
Operating and Maintenance	4,345	4,394	2,310
Merger-Related Costs	--	--	276
Depreciation and Amortization	1,340	1,449	458
Taxes Other Than Income	709	623	322
Total Operating Expenses	11,656	11,556	5,972
Operating Income	3,299	3,362	1,527
Other Income and Deductions			
Interest Expense, net of amounts capitalized	(966)	(1,107)	(614)
Distributions on Preferred Securities of Subsidiaries	(45)	(49)	(24)
Equity in Earnings (Losses) of Unconsolidated Affiliates, net	80	62	(41)
Other, Net	300	79	53
Total Other Income and Deductions	(631)	(1,015)	(626)
Income Before Income Taxes and the Cumulative Effect of Changes in Accounting Principles	2,668	2,347	901
Income Taxes	998	931	339

Income Before Cumulative Effect of Changes in Accounting Principles	1,670	1,416	562
Cumulative Effect of Changes in Accounting Principles (net of income taxes of $(90), $8 and $16 in 2002, 2001 and 2000, respectively)	(230)	12	24
Net Income	$ 1,440	$ 1,428	$ 586
Average Shares of Common Stock Outstanding			
Basic	322	320	202
Diluted	325	322	204
Earnings Per Common Share - Basic:			
Income Before Cumulative Effect of Changes in Accounting Principles	$ 5.18	$ 4.42	$ 2.79
Cumulative Effect of Changes in Accounting Principles	(0.71)	0.04	0.12
Net Income	$ 4.47	$ 4.46	$ 2.91
Earnings Per Common Share - Diluted:			
Income Before Cumulative Effect of Changes in Accounting Principles	$ 5.15	$ 4.39	$ 2.75
Cumulative Effect of Changes in Accounting Principles	(0.71)	0.04	0.12
Net Income	$ 4.44	$ 4.43	$ 2.87
Dividends Per Common Share	$ 1.76	$ 1.82	$ 0.91

See Notes to Consolidated Financial Statements

Exelon Corporation and Subsidiary Companies
Consolidated Statements of Cash Flows

in millions	For the Years Ended December 31, 2002	2001	2000
Cash Flows from Operating Activities			
Net Income	$ 1,440	$ 1,428	$ 586
Adjustments to reconcile Net Income to Net Cash Flows provided by Operating Activities:			
Depreciation and Amortization, including nuclear fuel	1,701	1,834	607
Cumulative Effects of Changes in Accounting Principles (net of income taxes)	230	(12)	(24)
Provision for Uncollectible Accounts	129	145	89
Net Gain on Sale of Investments	(199)	--	--
Deferred Income Taxes	278	(68)	193
Merger-Related Costs	--	--	276
Employee Severance Costs	--	46	--
Deferred Energy Costs	25	29	(79)
Equity in (Earnings) Losses of Unconsolidated Affiliates, net	(80)	(62)	41
Write-down of Investments	41	36	--
Net Realized Losses on Nuclear Decommissioning Trust Funds	32	127	--
Other Operating Activities	12	(16)	(165)
Changes in Working Capital:			
Accounts Receivable	(448)	318	(445)
Repurchase of Accounts Receivable	--	--	(50)
Inventories	(37)	(33)	49
Accounts Payable, Accrued Expenses & Other Current Liabilities	470	(190)	(2)
Other Current Assets	20	33	20
Net Cash Flows provided by Operating Activities	3,614	3,615	1,096
Cash Flows from Investing Activities			
Capital Expenditures	(2,150)	(2,088)	(752)
Acquisitions of Generating Plants	(445)	--	--
Unicom Merger Consideration	--	--	(507)
Proceeds from Direct Financing Leases	--	--	1,228
Investment in Sithe Energies, Inc.	--	--	(704)
Enterprises Acquisitions, net of cash acquired	--	(30)	(245)
Proceeds from the Sale of Investments	287	--	--
Proceeds from Nuclear Decommissioning Trust Funds	1,612	1,624	265
Investment in Nuclear Decommissioning Trust Funds	(1,824)	(1,863)	(380)
Note Receivable from Unconsolidated Affiliate	(35)	--	--
Other Investing Activities	17	(35)	(108)
Net Cash Flows used in Investing Activities	(2,538)	(2,392)	(1,203)
Cash Flows from Financing Activities			
Issuance of Long-Term Debt	1,223	2,270	1,021
Common Stock Repurchases	--	--	(501)
Retirement of Long-Term Debt	(2,134)	(1,860)	(665)
Change in Short-Term Debt	321	(1,013)	10
Redemption of Preferred Securities of Subsidiaries	(18)	(17)	(19)
Dividends Paid on Common Stock	(563)	(583)	(157)
Change in Restricted Cash	(24)	(58)	(140)
Proceeds from Employee Stock Plans	78	39	67
Contribution from Minority Interest of Consolidated Subsidiary	43	--	--
Other Financing Activities	(18)	(42)	(11)
Net Cash Flows used in Financing Activities	(1,092)	(1,264)	(395)
Decrease in Cash and Cash Equivalents	(16)	(41)	(502)
Cash and Cash Equivalents at beginning of period	485	526	54
Cash Acquired in Unicom Merger	--	--	974
Cash and Cash Equivalents at end of period	$ 469	$ 485	$ 526

See Notes to Consolidated Financial Statements

Exelon Corporation and Subsidiary Companies
Consolidated Balance Sheets

in millions	December 31, 2002	2001
Assets		
Current Assets		
Cash and Cash Equivalents	$ 469	$ 485
Restricted Cash	396	372
Accounts Receivable, net		
Customer	2,095	1,687
Other	265	381
Receivable from Unconsolidated Affiliate	32	44
Inventories, at average cost		
Fossil Fuel	218	222
Materials and Supplies	306	249
Deferred Income Taxes	6	23
Other	331	272
Total Current Assets	4,118	3,735
Property, Plant and Equipment, net	17,134	13,791
Deferred Debits and Other Assets		
Regulatory Assets	5,938	6,423
Nuclear Decommissioning Trust Funds	3,053	3,165
Investments	1,393	1,623
Goodwill, net	4,992	5,335
Other	850	672
Total Deferred Debits and Other Assets	16,226	17,218
Total Assets	$ 37,478	$ 34,744
Liabilities and Shareholders' Equity		
Current Liabilities		
Notes Payable	$ 681	$ 360
Note Payable to Unconsolidated Affiliate	534	--
Long-Term Debt Due Within One Year	1,402	1,406
Accounts Payable	1,563	964
Accrued Expenses	1,311	1,135
Other	483	505
Total Current Liabilities	5,974	4,370
Long-Term Debt	13,127	12,879
Deferred Credits and Other Liabilities		
Deferred Income Taxes	3,702	4,362
Unamortized Investment Tax Credits	301	316
Nuclear Decommissioning Liability for Retired Plants	1,395	1,353
Pension Obligation	1,959	334
Non-Pension Postretirement Benefits Obligation	877	847
Spent Nuclear Fuel Obligation	858	843
Other	871	694
Total Deferred Credits and Other Liabilities	9,963	8,749
Commitments and Contingencies		
Minority Interest of Consolidated Subsidiaries	77	31
Preferred Securities of Subsidiaries	595	613
Shareholders' Equity		
Common Stock	7,059	6,961
Deferred Compensation	(1)	(2)
Retained Earnings	2,042	1,169
Accumulated Other Comprehensive Income (Loss)	(1,358)	(26)
Total Shareholders' Equity	7,742	8,102
Total Liabilities and Shareholders' Equity	$ 37,478	$ 34,744

See Notes to Consolidated Financial Statements

Exelon Corporation and Subsidiary Companies
Consolidated Statements of Changes in Shareholders' Equity

Dollars in millions, shares in thousands	Shares	Common Stock	Deferred Compensation	Retained Earnings	Treasury Shares	Accumulated Other Comprehensive Income (Loss)	Total Shareholders' Equity
Balance, December 31, 1999	225,354	$ 3,577	$ (3)	$ (100)	$ (1,705)	$ 4	$ 1,773
Net Income		--	--	586	--	--	586
Long-Term Incentive Plan Activity	563	75	(9)	--	7	--	73
Shares Issued to Acquire Unicom	147,963	5,310	--	--	--	--	5,310
Merger Consideration-Stock Options		111	--	--	--	--	111
Amortization of Deferred Compensation		--	5	--	--	--	5
Common Stock Dividends Declared		--	--	(157)	--	--	(157)
Common Stock Repurchases		--	--	(5)	(496)	--	(501)
Stock Option Exercises		--	--	--	19	--	19
Cancellation of Treasury Shares	(54,875)	(2,175)	--	--	2,175	--	--
Other Comprehensive Income (Loss), net of income taxes of $(1)		--	--	--	--	(4)	(4)
Balance, December 31, 2000	319,005	$ 6,898	$ (7)	$ 324	$ --	$ --	$ 7,215
Net Income		--	--	1,428	--	--	1,428
Long-Term Incentive Plan Activity	1,864	55	--	--	--	--	55
Employee Stock Purchase Plan Issuances	138	6	--	--	--	--	6
Merger Consideration-Stock Options		2	--	--	--	--	2
Amortization of Deferred Compensation		--	5	--	--	--	5
Common Stock Dividends Declared		--	--	(583)	--	--	(583)
Reclassified Net Unrealized Losses on Marketable Securities, net of income taxes of $(22)		--	--	--	--	(23)	(23)
Other Comprehensive Income (Loss), net of income taxes of $(7)		--	--	--	--	(3)	(3)
Balance, December 31, 2001	321,007	$ 6,961	$ (2)	$ 1,169	$ --	$ (26)	$ 8,102
Net Income		--	--	1,440	--	--	1,440
Long-Term Incentive Plan Activity	2,049	87	--	--	--	--	87
Employee Stock Purchase Plan Issuances	257	11	--	--	--	--	11
Amortization of Deferred Compensation		--	1	--	--	--	1
Common Stock Dividends Declared		--	--	(567)	--	--	(567)
Other Comprehensive Income (Loss), net of income taxes of $(850)		--	--	--	--	(1,332)	(1,332)
Balance, December 31, 2002	323,313	$ 7,059	$ (1)	$ 2,042	$ --	$ (1,358)	$ 7,742

Exelon Corporation and Subsidiary Companies
Consolidated Statements of Comprehensive Income

	For the Years Ended December 31,		
in millions	2002	2001	2000
Net Income	$ 1,440	$ 1,428	$ 586
Other Comprehensive Income (Loss)			
Minimum Pension Liability, net of income taxes of $(597)	(1,007)	--	--
SFAS No. 133 Transition Adjustment, net of income taxes of $32	--	44	--
Cash Flow Hedge Fair Value Adjustment, net of income taxes of $(132) and $17, respectively	(199)	22	--
Foreign Currency Translation Adjustment, net of income taxes of $0	--	(1)	--
Unrealized Gain (Loss) on Marketable Securities, net of income taxes of $(116), $(40) and $(1), respectively	(119)	(41)	(4)
Interest in Other Comprehensive Income (Loss) of Unconsolidated Affiliates, net of income taxes of $(5) and $(16), respectively	(7)	(27)	--
Total Other Comprehensive Income (Loss)	(1,332)	(3)	(4)
Total Comprehensive Income	$ 108	$ 1,425	$ 582

See Notes to Consolidated Financial Statements

1. Significant Accounting Policies

Description of Business

Exelon Corporation (Exelon) is a utility services holding company formed as a result of the merger of Unicom Corporation (Unicom), the former parent company of Commonwealth Edison Company (ComEd), and PECO Energy Company (PECO) (Merger) (see Note 2 - Merger). Exelon is engaged, through its subsidiaries, in the energy delivery, wholesale generation and the enterprises businesses discussed below (see Note 20 - Segment Information). The Energy Delivery segment's businesses include the sale of electricity and distribution and transmission services by ComEd in northern Illinois and PECO in southeastern Pennsylvania and the sale of natural gas and distribution services by PECO in the Pennsylvania counties surrounding the City of Philadelphia. The wholesale generation business consists of the electric generating facilities and energy marketing operations of Exelon Generation Company, LLC (Generation) and Generation's interests in Sithe Energies, Inc. (Sithe) and AmerGen Energy Company, LLC (AmerGen). Exelon Enterprises Company, LLC (Enterprises) includes energy and infrastructure services, competitive retail energy sales, communications joint ventures and other investments weighted towards the communications, energy services and retail services industries.

Basis of Presentation

The consolidated financial statements of Exelon include the accounts of its majority-owned subsidiaries after the elimination of intercompany transactions. Investments and joint ventures in which a 20% to 50% interest is owned and a significant influence is exerted are accounted for under the equity method of accounting. The proportionate interests in jointly owned electric utility plants are consolidated. Investments in which less than a 20% interest is owned are primarily accounted for under the cost method of accounting. Exelon owns 100% of all significant consolidated subsidiaries, either directly or indirectly, except for ComEd of which Exelon owns more than 99%, InfraSource Inc. (InfraSource) of which Exelon owns 95% and Southeast Chicago Energy Project, LLC of which Exelon owns 70% through Generation. Exelon has reflected the third-party interests in the above majority owned investments as minority interests in its Consolidated Statements of Cash Flows, Consolidated Balance Sheets and in Other, Net on the Consolidated Statements of Income. Accounting policies for regulated operations are in accordance with those prescribed by the regulatory authorities having jurisdiction, principally the Illinois Commerce Commission (ICC), the Pennsylvania Public Utility Commission (PUC), the Federal Energy Regulatory Commission (FERC) and the Securities and Exchange Commission (SEC) under the Public Utility Holding Company Act of 1935 (PUHCA). On October 20, 2000, Exelon became the parent of PECO through a share exchange and Unicom was merged into Exelon. As a result of these transactions, Unicom ceased to exist and Exelon became the parent of ComEd and PECO (see Note 2 - Merger). For accounting purposes, PECO was deemed the acquiror in the Merger. Accordingly, the financial statements of Exelon for the periods presented prior to October 20, 2000 represent the historical financial statements of PECO and for the periods from October 20, 2000 include the operations acquired from Unicom.

Accounting for the Effects of Regulation

Exelon accounts for all of its regulated electric and gas operations in accordance with the Financial Accounting Standards Board (FASB) Statement of Financial Accounting Standards (SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulation," (SFAS No. 71) requiring Exelon to record in its financial statements the effects of rate regulation. Use of SFAS No. 71 is applicable to the utility operations of Exelon 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 currently recorded regulatory assets will be recovered. If a separable portion of Exelon's business no longer meets the provisions of SFAS No. 71, Exelon is required to eliminate the financial statement effects of regulation for that portion.

Use of Estimates

The preparation of financial statements in conformity with generally accepted accounting principles (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 derivatives, nuclear decommissioning liabilities, asset impairment analyses, environmental costs and pension costs.

Revenues

Operating revenues are generally 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 its electric and gas customers (see Note 8 - Accounts Receivable). Exelon recognizes contract revenues and profits on certain long-term fixed-price contracts from its services businesses under the percentage-of-completion method of accounting based on costs incurred as a percentage of estimated total costs of individual contracts. Premiums received and paid on option contracts and swap arrangements are amortized to revenue and expense over the life of the contracts. Certain of these contracts 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. Under this methodology, these derivatives are adjusted to fair value, and the unrealized gains and losses are recognized in current period income.

Long-Term Contract Accounting

Enterprises recognizes contract revenue and profits on certain long-term fixed-price contracts by the percentage-of-completion method of accounting. In determining the amount of revenue to recognize, Exelon is required to estimate the total costs and profits expected to be recorded under the contract over its contract term, and the recoverability of costs related to change orders. Changes in these estimates could result in the recognition of differences in earnings. At December 31, 2002 and 2001, Current Assets includes $70 million and $77 million, respectively, of Costs and Earnings in Excess of Billings on uncompleted contracts and Current Liabilities includes $44 million and $56 million, respectively, of Billings and Earnings in Excess of Costs on uncompleted contracts.

At December 31, 2002 and 2001, Accounts Receivable includes $49 million and $46 million, respectively, of contract retention. This amount represents revenue recognized on costs incurred that is not yet billable until final completion of the project and acceptance by the customer. In applying the percentage-of-completion accounting method, the collection of these estimated revenues is deemed probable.

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 base 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.

Nuclear Fuel

The cost of nuclear fuel is capitalized and charged to fuel expense using the unit of production method. Estimated costs of nuclear fuel storage and disposal at operating plants are charged to fuel expense as the related fuel is consumed.

Stock-Based Compensation

Exelon uses the disclosure-only provisions of SFAS No. 123, "Accounting for Stock-Based Compensation" (SFAS No. 123). See Note 17 - Common Stock for further discussion of these plans. The table below shows the effect on net income and earnings per share had Exelon elected to account for its stock-based compensation plans using the fair value method under SFAS No. 123 for the years ended December 31, 2002, 2001 and 2000:

	2002	2001	2000
Net income - as reported	$ 1,440	$ 1,428	$ 586
Deduct: Total stock-based compensation expense determined under fair value based method for all awards, net of income taxes	33	26	25
Pro forma net income	$ 1,407	$ 1,402	$ 561
Earnings per share:			
Basic - as reported	$ 4.47	$ 4.46	$ 2.91
Basic - pro forma	$ 4.36	$ 4.38	$ 2.77
Diluted - as reported	$ 4.44	$ 4.43	$ 2.87
Diluted - pro forma	$ 4.33	$ 4.35	$ 2.75

Income Taxes

Deferred Federal and state income taxes are provided on all significant temporary differences between book basis and tax basis of assets and liabilities. 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. Exelon and its subsidiaries file a consolidated Federal income tax return. Income taxes are allocated to each of Exelon's subsidiaries within the consolidated group based on the separate return method. Exelon estimates its income tax valuation allowance by assessing which deferred tax assets are more likely than not to be recovered in the future (see Note 14 - Income Taxes).

Gains and Losses on Reacquired Debt

Recoverable gains and losses on reacquired debt related to regulated operations are deferred and amortized to interest expense over the period consistent with rate recovery for ratemaking purposes. Gains and losses on other debt are recognized in Exelon's Consolidated Statements of Income as incurred (see Note 6 - 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. 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

Restricted cash reflects escrowed cash to be applied to the principal and interest payment on the transition bonds and transitional trust notes.

Marketable Securities

Marketable securities are classified as available-for-sale securities and are reported at fair value, with the unrealized gains and losses, net of tax, reported in other comprehensive income. Under regulatory accounting practices, unrealized gains and losses on marketable securities held in the nuclear decommissioning trust funds are reported in accumulated depreciation for operating units and as a reduction of regulatory assets for retired units. If regulatory accounting practices are not applicable, unrealized gains and losses on marketable securities held in the nuclear decommissioning trust funds are reported in accumulated other comprehensive income. At December 31, 2002 and 2001, Exelon had no held-to-maturity or trading securities.

Property, Plant and Equipment

Property, plant and equipment is recorded at cost. Exelon evaluates the carrying value of property, plant and equipment and other long-term assets based upon current and anticipated undiscounted cash flows, and recognizes an impairment when it is probable that such estimated cash flows will be less than the carrying value of the asset. Measurement of the amount of impairment, if any, is based upon the difference between the carrying value and fair value. The cost of maintenance, repairs and minor replacements of property is charged to maintenance expense as incurred.

Upon retirement, the cost of regulated property plus removal costs less salvage value is charged to accumulated depreciation by the regulated subsidiaries in accordance with regulatory practices. For unregulated property, the cost and accumulated depreciation of property, plant and equipment retired or otherwise disposed of are removed from the related accounts and included in the determination of the gain or loss on disposition.

Depreciation, Amortization and Decommissioning

Depreciation is provided over the estimated service lives of property, plant and equipment on a straight-line basis. Annual depreciation provisions for financial reporting purposes, expressed as a percentage of average service life for each asset category, are presented in the table below. See Note 4 - Adoption of New Accounting Pronouncements and Accounting Changes for information on service life extensions for certain nuclear generating stations and Energy Delivery's change in depreciation rates.

Asset Category	2002	2001	2000
Electric-Transmission and Distribution	3.11%	3.97%	4.16%
Electric-Generation	3.65%	3.11%	5.02%
Gas	2.13%	2.34%	2.39%
Common - Gas and Electric	6.40%	6.26%	5.09%
Other Property and Equipment	7.88%	9.53%	8.11%

Amortization of regulatory assets is provided over the recovery period specified in the related regulatory agreement. Goodwill associated with the Merger was amortized on a straight-line basis over 40 years in 2001 and 2000. Goodwill associated with other acquisitions was amortized over periods from 10 to 20 years in 2001 and 2000. Accumulated amortization of goodwill was $185 million and $35 million at December 31, 2001 and 2000, respectively. Effective January 1, 2002, under SFAS No. 142 "Goodwill and Other Intangible Assets" (SFAS No. 142), goodwill recorded by Exelon is no longer subject to amortization but is subject to an annual impairment test (see Note 4 - Adoption of New Accounting Pronouncements and Accounting Changes).

Exelon currently recovers costs for decommissioning its nuclear generating stations, excluding AmerGen, through regulated rates. The amounts recovered from customers are deposited in trust accounts and invested for funding of future costs for operating and retired nuclear generating stations. The majority of the eventual work to decommission Exelon's nuclear generating stations will occur after 2029.

Exelon accounts for the current period's cost of decommissioning related to generating plants previously owned by PECO following common regulatory accounting practices by recording a charge to depreciation expense and a corresponding liability in accumulated depreciation concurrently with decommissioning collections. Financial activity of the decommissioning trust (e.g., investment income and realized and unrealized gains and losses on trust investments) is reflected in Nuclear Decommissioning Trust Funds in Exelon's Consolidated Balance Sheets with a corresponding offset recorded to the liability in accumulated depreciation. Under common regulatory practices, the deposit of funds into the decommissioning trust accounts plus the financial activity reflected in Nuclear Decommissioning Trust Funds in Exelon's Consolidated Balance Sheets will, over time, establish a corresponding liability in accumulated depreciation reflecting the cost to decommission the nuclear generating stations previously owned by PECO. Exelon will adopt SFAS No. 143, "Asset Retirement Obligations" (SFAS No. 143) as of January 1, 2003. See "New Accounting Pronouncements" within this note for a discussion as to how this standard will change the accounting for nuclear decommissioning costs.

Regulatory accounting practices for the nuclear generating stations previously owned by ComEd were discontinued as a result of an ICC order capping ComEd's ultimate recovery of decommissioning costs. See Note 11 - Nuclear Decommissioning and Spent Fuel Storage regarding regulatory accounting practices for nuclear generating stations transferred by ComEd to Generation. The difference between the current decommissioning cost estimate and the decommissioning liability recorded in accumulated depreciation for the former ComEd operating stations is being amortized to depreciation expense on a straight-line basis over the remaining lives of the stations. The current decommissioning cost estimate (adjusted annually to reflect inflation) for the former ComEd retired units recorded in deferred credits and other liabilities is accreted to depreciation expense. Financial activity of the decommissioning trust related to Exelon's nuclear generating stations no longer accounted for under common regulatory practices (e.g., investment income and realized and unrealized gains and losses on trust investments) is reflected in Nuclear Decommissioning Trust Funds in Exelon's Consolidated Balance Sheets with a corresponding gain or expense recorded in Exelon's Consolidated Income Statement or in other comprehensive income. The offset to the financial activity in the decommissioning trust funds is summarized as follows:

- Interest income is recorded in other income and deductions,
- Realized gains and losses are recorded in other income and deductions,
- Unrealized gains and losses are recorded in other comprehensive income, and
- Trust fund operating expenses are recorded in operation and maintenance expense

Exelon believes that the amounts being recovered from customers through electric rates along with the earnings on the trust funds will be sufficient to fully fund its decommissioning obligations.

Capitalized Interest

Exelon uses SFAS No. 34, "Capitalizing Interest Costs," to calculate the costs during construction of debt funds used to finance its non-regulated construction projects. Exelon recorded capitalized interest of $20 million, $17 million and $2 million in 2002, 2001 and 2000, 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 Other Income and Deductions. The rates used for capitalizing AFUDC are computed under a method prescribed by regulatory authorities (see Note 6 - Supplemental Financial Information).

Capitalized Software Costs

Costs incurred during the application development stage of software projects for software that is developed or obtained for internal use are capitalized. At December 31, 2002, 2001 and 2000, capitalized software costs totaled $335 million, $240 million and $285 million, respectively, net of $156 million, $85 million and $53 million of accumulated amortization, respectively. Such capitalized amounts are amortized ratably over the expected lives of the projects when they become operational, not to exceed ten years. Certain capitalized software is being amortized over fifteen years pursuant to regulatory approval.

Derivative Financial Instruments

Exelon accounts 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 and normal sales exception. Normal purchases and normal sales are contracts where physical delivery is probable, quantities are expected to be used or sold in the normal course of business over a reasonable period of time, and price is not tied to an unrelated underlying derivative. Changes in the fair value of the derivative financial instruments that do not qualify for a normal purchase and normal sales exception are recognized in earnings unless specific hedge accounting criteria are met. 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 as, and is designated and qualifies as, a fair value hedge, along with the gain or loss on the hedged asset or liability that is attributable to the hedged risk, are recorded in earnings. Changes in the fair value of a derivative that is highly effective as, and is designated as and qualifies as a cash flow hedge are recorded in other comprehensive income, until earnings are affected by the variability of cash flows being hedged.

In connection with Exelon's Risk Management Policy (RMP), Exelon enters into derivatives to manage its exposure to fluctuations in interest rates related to its variable rate debt instruments, changes in interest rates related to planned future debt issuances prior to their actual issuance and changes in the fair value of outstanding debt which is planned for early retirement. As it relates to energy transactions, Exelon utilizes derivatives to manage the utilization of its available generating capability and provisions 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, Exelon enters into certain energy related derivatives for trading or speculative purposes.

As part of Exelon's energy marketing business, Exelon 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 not subject to the provisions of SFAS No. 133. Under these contracts, Exelon recognizes gains or losses when the underlying physical transaction affects earnings. Revenues and expenses associated with market price risk management contracts are amortized over the terms of such contracts. Commitments under these contracts are discussed in Note 19 - Commitments and Contingencies. The remainder of these contracts are generally considered cash flow hedges under SFAS No. 133. To the extent that the hedges are effective, changes in the fair value of these contracts are recorded in other comprehensive income, until earnings are affected by the variability of cash flows being hedged.

Additionally, during 2001, as part of the creation of Exelon's energy trading operation, Exelon began to enter into contracts to buy and sell energy for trading purposes subject to limits. 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.

Prior to the adoption of SFAS No. 133, Exelon applied hedge accounting only if the derivative reduced the risk of the underlying hedged item and was designated at the inception of the hedge, with respect to the hedged item. Exelon recognized any gains or losses on these derivatives when the underlying physical transaction affected earnings.

Contracts entered into by Exelon to limit market risk associated with forward energy commodity contracts are reflected in the financial statements at the lower of cost or market using the accrual method of accounting. Under these contracts, Exelon recognizes any gains or losses when the underlying physical transaction affects earnings. Revenues and expenses associated with market price risk management contracts are amortized over the terms of such contracts.

New Accounting Pronouncements

In 2001, the FASB issued SFAS No. 143, "Asset Retirement Obligations" (SFAS No. 143). SFAS No. 143 provides accounting requirements for retirement obligations associated with tangible long-lived assets. Exelon will adopt SFAS No. 143 as of January 1, 2003. Retirement obligations associated with long-lived assets included within the scope of SFAS No. 143 are those for which there is a legal obligation to settle under existing or enacted law, statute, written or oral contract or by legal construction under the doctrine of promissory estoppel. Adoption of SFAS No. 143 will change the accounting for the decommissioning of Generation's nuclear generating plants as well as certain other long-lived assets.

As it relates to nuclear decommissioning, the effect of this cumulative adjustment will be to decrease the decommissioning liability to reflect the fair value of the decommissioning obligation at the balance sheet date. Additionally, SFAS No. 143 will require the recognition of an asset related to the decommissioning obligation, which will be amortized over the remaining lives of the plants. The net difference, between the asset recognized and the change in the liability to reflect fair value recorded upon adoption of SFAS No. 143, will be recorded in earnings and recognized as a cumulative effect of a change in accounting principle, net of expected regulatory recovery and income taxes. The decommissioning liability will then represent an obligation for the future decommissioning of the plants and, as a result, accretion expense will be accrued on this liability until such time as the obligation is satisfied.

Currently, Generation records the obligation for decommissioning ratably over the lives of the plants. Based on the current information and the credit-adjusted risk-free rate, we estimate the increase in 2003 non-cash expense to impact earnings before the cumulative effect of a change in accounting principle for the adoption of SFAS No. 143 by approximately $24 million, after income taxes. Additionally, the adoption of SFAS No. 143 is expected to result in a large, non-cash, one-time cumulative effect of a change in accounting principle gain of at least $1.5 billion, after income taxes. The $1.5 billion gain and the $24 million charge includes our share of the impact of the SFAS No. 143 adoption related to AmerGen's nuclear plants. These impacts are based on our current interpretation of SFAS No. 143 and are subject to continued refinement based on the finalization of assumptions and interpretation at the time of adopting the standard, including the determination of the credit-adjusted risk-free rate. Under SFAS No. 143, the fair value of the nuclear decommissioning obligation will continue to be adjusted on an ongoing basis as these model input factors change.

The final determination of the 2003 earnings impact and the cumulative effect of adopting SFAS No. 143, is in part a function of the credit adjusted risk-free rate at the time of the adoption of SFAS No. 143. Additionally, although over the life of the plant the charges to earnings for the depreciation of the asset and the interest on the liability will be equal to the amounts that would have been recognized as decommissioning expense under the current accounting, the timing of those charges will change and in the near-term period subsequent to adoption, the depreciation of the asset and the interest on the liability is expected to result in an increase in expense.

In July 2002, the FASB issued SFAS No. 146, "Accounting for Costs Associated with Exit or Disposal Activities" (SFAS No. 146). SFAS No. 146 requires that the liability for costs associated with exit or disposal activities be recognized when incurred, rather than at the date of a commitment to an exit or disposal plan. SFAS No. 146 is to be applied prospectively to exit or disposal activities initiated after December 31, 2002.

In November 2002, the FASB released FASB Interpretation No. (FIN) 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others" (FIN No. 45), providing for expanded disclosures and recognition of a liability for the fair value of the obligation undertaken by the guarantor. Under FIN No. 45, guarantors are required to disclose the nature of the guarantee, the maximum amount of potential future payments, the carrying amount of the liability and the nature and amount of recourse provisions or available collateral that would be recoverable by the guarantor. Exelon has adopted the disclosure requirements under FIN No. 45, (see Note 19 - Commitments and Contingencies) which were effective for financial statements for periods ended after December 15, 2002. The recognition and measurement provisions of FIN No. 45 are effective, on a prospective basis, for guarantees issued or modified after December 31, 2002.

In January 2003, the FASB issued FIN No. 46, "Consolidation of Variable Interest Entities" (FIN No. 46). FIN No. 46 addresses consolidating certain variable interest entities and applies immediately to variable interest entities created after January 31, 2003. The impact, if any, of adopting FIN 46 on our consolidated financial position, results of operations and cash flows, has not been fully determined.

See Note 4 - Adoption of New Accounting Pronouncements and Accounting Changes for discussion of the impact of new accounting pronouncements adopted by Exelon.

Reclassifications

Certain prior year amounts have been reclassified for comparative purposes. The reclassifications did not affect net income or shareholders' equity.

2. Merger

On October 20, 2000, Exelon became the parent corporation of PECO and ComEd as a result of the completion of the transactions contemplated by an Agreement and Plan of Exchange and Merger, as amended (Merger Agreement), among PECO, Unicom and Exelon. Pursuant to the Merger Agreement, Unicom merged with and into Exelon. In the Merger, each share of the outstanding common stock of Unicom was converted into 0.875 shares of common stock of Exelon plus $3.00 in cash. As a result of the Share Exchange, Exelon became the owner of all of the common stock of PECO. As a result of the Merger, Unicom ceased to exist and its subsidiaries, including ComEd, became subsidiaries of Exelon.

The Merger was accounted for using the purchase method of accounting. The total purchase price was $6,014 million. In connection with the Merger, Exelon issued 148 million shares of common stock in the amount of $5,310 million and paid $507 million in cash to Unicom shareholders pursuant to the terms of the Merger Agreement. The source of the cash consideration was borrowings under an Exelon term loan. In addition, the Merger consideration included $113 million of fair value of stock options and awards for certain Unicom employees and $84 million of direct acquisition costs. The cost in excess of net assets acquired was $5,150 million as adjusted to reflect final purchase price allocations. Exelon's results of operations include Unicom's results of operations since October 20, 2000. The fair value of the assets acquired, including the cost in excess of net assets acquired, and liabilities assumed in the Merger are as follows:

Current Assets (including cash of $974)	$ 2,744
Property, Plant and Equipment	7,641
Deferred Debits and Other Assets	5,535
Cost in excess of net assets acquired	5,150
Current Liabilities	(2,390)
Long-Term Debt	(7,419)
Deferred Credits and Other Liabilities	(4,919)
Preferred Securities of Subsidiaries	(328)
Total Purchase Price	$ 6,014

Goodwill associated with the Merger increased by $14 million and $262 million in 2002 and 2001, respectively, as a result of the finalization of the purchase price allocation. The adjustment resulted primarily from the after-tax effects of the reduction of the regulatory asset for decommissioning retired nuclear plants, as discussed in Note 11 - Nuclear Decommissioning and Spent Fuel Storage, additional employee separation costs, the resolution of certain tax matters and the finalization of other purchase price allocations.

Selected unaudited pro forma combined results of operations for the year ended December 31, 2000, assuming the Merger Transaction occurred on January 1, 2000 are presented as follows:

(unaudited)	2000
Total revenues	$ 13,531
Pro forma net income	$ 1,003
Merger-related costs (net of income taxes of $147)	220
Cumulative effect of a change in accounting principle (net of income taxes of $16)	24
Pro forma net income before Merger-related costs and the cumulative effect of a change in accounting principle	$ 1,247
Pro forma net income before Merger-related costs and the cumulative effect of a change in accounting principle per common share (diluted)	$ 3.86

Pro forma information assumes the issuance of transition bonds in 2000 had occurred at the beginning of 2000. The pro forma financial information is not necessarily indicative of the operating results that would have occurred had the Merger been consummated as of the dates indicated, nor are they necessarily indicative of future operating results.

Merger-Related Costs

In association with the Merger, Exelon recorded certain reserves for restructuring costs. The reserves associated with PECO were charged to expense pursuant to FASB Emerging Issues Task Force (EITF) Issue 94-3, "Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (including Certain Costs Incurred in a Restructuring)"; while the reserves associated with Unicom were recorded as part of the application of purchase accounting and did not affect results of operations, consistent with EITF Issue 95-3, "Recognition of Liabilities in Connection with a Purchase Business Combination."

Merger costs charged to expense. PECO's merger-related costs charged to expense in 2000 were $248 million, consisting of $116 million for PECO employee costs and $132 million of direct incremental costs incurred by PECO in conjunction with the merger transaction. Direct incremental costs represent expenses directly associated with completing the Merger, including professional fees, regulatory approval and settlement costs, and settlement of compensation arrangements. Employee costs represent estimated severance costs and pension and postretirement benefits provided under Exelon's merger separation plans for eligible employees who were expected to be involuntarily terminated before December 2002 due to integration activities of the merged companies. Additional employee severance costs of $48 million, primarily related to PECO employees, were charged to operating and maintenance expense in 2001, and a $10 million reduction in the estimated liability related to Generation employees was recorded in operating and maintenance expense in the first quarter of 2002. Employee costs are being paid from Exelon's pension and postretirement benefit plans, except for certain benefits such as outplacement services, continuation of health care coverage and educational benefits. As of December 31, 2002, a liability of $4 million is reflected on Exelon's consolidated balance sheet for payment of these benefits, of which $1 million is reflected on PECO's balance sheet and $1 million is reflected on Generation's balance sheet.

A total of 960 PECO positions were expected to be eliminated as a result of the Merger, 274 of which related to generation, 230 of which related to PECO energy delivery and 456 of which related to enterprises and corporate support areas. As of December 31, 2002, 858 of the positions had been eliminated, of which 224 related to generation, 195 related to PECO energy delivery, and 439 to enterprises and corporate support. Of the remaining 102 positions, 58 were eliminated as a result of normal attrition and 44 positions will not be eliminated due to changes in certain business plans.

Additionally, in the third quarter of 2000, approximately $20 million of closing costs and $8 million of stock compensation costs associated with Unicom were charged to expense.

Merger costs included in purchase price allocation. The purchase price allocation as of December 31, 2000 included a liability of $307 million for Unicom employee costs and liabilities of approximately $39 million for estimated costs of exiting various business activities of former Unicom activities that were not compatible with the strategic business direction of Exelon.

During 2001, Exelon finalized plans for consolidation of functions, including negotiation of an agreement with the International Brotherhood of Electrical Workers Local 15 regarding severance benefits to union employees. In the third quarter of 2002, Exelon reduced its reserve by $12 million due to the elimination of identified positions through normal attrition, which did not require payments under Exelon's merger separation plans, and a determination that certain positions would not be eliminated by the end of 2002, as originally planned, due to a change in certain business plans. The reduction in the reserve was recorded as a purchase price adjustment to goodwill. In 2001 and 2002, Exelon recorded adjustments to the purchase price allocation as follows:

	Original Estimate	Adjustments 2001	Adjustments 2002	Adjusted Liabilities	
Employee severance payments	$ 128	$ 33	$ (10)	$ 151	(a)
Other benefits	21	9	(2)	28	(a)
Employee severance payments and other benefits	149	42	(12)	179	
Actuarially determined pension and postretirement costs	158	(11)	--	147	(b)
Total Unicom employee cost	$ 307	$ 31	$ (12)	$ 326	

(a) The increase is a result of the identification in 2001 of additional positions to be eliminated, partially offset by the 2002 elimination of identified positions through normal attrition and changes in certain business plans.

(b) The reduction results from lower estimated pension and postretirement welfare benefits reflecting revised actuarial estimates.

The following table provides a reconciliation of the reserve for employee severance and other benefits associated with the Merger:

Adjusted employee severance and other benefits reserve	$ 179
Payments to employees in 2000	(5)
Payments to employees in 2001	(72)
Payments to employees in 2002	(74)
Employee severance and other benefits reserve as of December 31, 2002 (1)	$ 28

(1) Relates to certain benefits that are being paid after 2002.

The following table provides a reconciliation of the former Unicom positions that were expected to be eliminated as a result of the Merger:

	Total
Estimate at October 20, 2000	2,275
2001 adjustments (a)	118
Total positions	2,393
Employees terminated in 2000	279
Employees terminated in 2001	607
Employees terminated in 2002	1,053
Normal attrition	298
Business plan changes (b)	156
Total positions	2,393

(a) The increase is a result of the identification of additional positions to be eliminated in 2001.

(b) The reduction is due to a determination in the third quarter of 2002, that certain positions would not be eliminated by the end of 2002 as originally planned due to a change in certain business plans.

3. Acquisitions and Dispositions

Sithe New England Holdings Asset Acquisition

On November 1, 2002, Generation purchased the assets of Sithe New England Holdings, LLC (Sithe New England), a subsidiary of Sithe, and related power marketing operations. Sithe New England's primary assets are gas-fired facilities currently under development. The purchase price for the Sithe New England assets consisted of a $534 million note to Sithe, $14 million of direct acquisition costs and an adjustment to Generation's investment in Sithe to reflect Sithe's sale of Sithe New England to Generation. Additionally, Generation will assume various Sithe guarantees related to an equity contribution agreement between Sithe New England and Sithe Boston Generation, LLC (SBG), a project subsidiary of Sithe New England. The equity contribution agreement requires, among other things, that Sithe New England, upon the occurrence of certain events, contribute up to $38 million of equity for the purpose of completing the construction of two generating facilities. SBG has a $1.25 billion credit facility (the SBG Facility) to finance the construction of these two generating facilities. The $1.0 billion outstanding under the facility at December 31, 2002 is reflected on Exelon's Consolidated Balance Sheet. Sithe New England owns 4,066 megawatts (MWs) of generation capacity, consisting of 1,645 MWs in operation and 2,421 MWs under construction. Sithe New England's generation facilities are located primarily in Massachusetts.

The allocation of purchase price to the fair value of assets acquired and liabilities assumed in the acquisition is as follows:

Current Assets (including $12 of cash acquired)	$ 82
Property, Plant and Equipment	1,889
Deferred Debits and Other Assets	62
Current Liabilities	(159)
Deferred Credits and Other Liabilities	(124)
Long-Term Debt	(1,036)
Total Purchase Price	$ 714

The SBG Facility provides that if these construction projects are not completed by June 12, 2003, the SBG Facility lenders will have the right, but will not be required, to, among other things, declare all amounts then outstanding under the SBG Facility and the interest rate swap agreements to be due. Generation believes that the construction projects will be substantially complete by May 31, 2003, but that all of the approvals required under the SBG Facility may not be issued by that date. Generation is currently evaluating whether the requirements of the SBG Facility relating to the construction projects can be satisfied by June 12, 2003. In the event that the requirements are not expected to be satisfied by June 12, 2003, Generation will contact the SBG Facility lenders concerning an amendment or waiver of these provisions of the SBG Facility. Generation currently expects that arrangements for such an amendment or waiver, if necessary, can be successfully negotiated with the SBG Facility lenders.

See Note 19 - Commitments and Contingencies for further discussion of Sithe.

Acquisition of Generating Plants from TXU

On April 25, 2002, Generation acquired two natural-gas and oil-fired plants from TXU Corp. (TXU) for an aggregate purchase price of $443 million. The purchase included the 893-megawatt Mountain Creek Steam Electric Station in Dallas and the 1,441-megawatt Handley Steam Electric Station in Fort Worth. The transaction included a purchased power agreement for TXU to purchase power during the months of May through September from 2002 through 2006. During the periods covered by the purchased power agreement, TXU will make fixed capacity payments, variable expense payments, and will provide fuel to Exelon in return for exclusive rights to the energy and capacity of the generation plants. Substantially all of the purchase price has been allocated to property, plant and equipment.

Sale of AT&T Wireless

On April 1, 2002, Enterprises sold its 49% interest in AT&T Wireless PCS of Philadelphia, LLC to a subsidiary of AT&T Wireless Services for $285 million in cash. Enterprises recorded an after-tax gain of $116 million in Other Income and Deductions on Exelon's Consolidated Statements of Income on its $84 million investment, which had been reflected in Deferred Debits and Other Assets on Exelon's Consolidated Balance Sheets.

InfraSource Acquisitions

In 2001, Exelon's infrastructure services business (InfraSource), acquired the assets of a utility service contracting company for an aggregate purchase price of approximately $31 million. The acquisition was accounted for using the purchase method of accounting. The excess of purchase price over the fair value of net assets acquired was $19 million. The allocation of purchase price to the fair value of assets acquired and liabilities assumed in the acquisition is as follows:

Current Assets (including cash acquired of $1)	$	11
Property, Plant and Equipment		11
Cost in excess of net assets acquired		19
Current Liabilities		(10)
Total	$	31

AmerGen Energy Company, LLC

In August 2000, AmerGen, a joint venture with British Energy, Inc., a wholly owned subsidiary of British Energy plc, (British Energy), completed the purchase of Oyster Creek Nuclear Generating Facility (Oyster Creek) from GPU, Inc. (GPU) for $10 million. Under the terms of the purchase agreement, GPU agreed to fund outage costs of $89 million, including the cost of fuel, for a refueling outage that occurred in 2000. AmerGen is repaying these costs to GPU in equal annual installments through 2009. In addition, AmerGen assumed full responsibility for the ultimate decommissioning of Oyster Creek. At the closing of the sale, GPU provided funding for the decommissioning trust of $440 million. In conjunction with this acquisition, AmerGen has received a fully funded decommissioning trust fund which has been computed assuming the anticipated costs to appropriately decommission Oyster Creek discounted to net present value using the NRC's mandated rate of 2%. AmerGen believes that the amount of the trust fund and investment earnings thereon will be sufficient to meet its decommissioning obligation. GPU is purchasing the electricity generated by Oyster Creek pursuant to a three-year power purchase agreement.

4. Adoption of New Accounting Pronouncements and Accounting Changes

SFAS No. 141 and SFAS No. 142

In 2001, FASB issued SFAS No. 141, "Business Combinations" (SFAS No. 141), which requires that all business combinations be accounted for under the purchase method of accounting and establishes criteria for the separate recognition of intangible assets acquired in business combinations. SFAS No. 141 became effective for business combinations initiated after June 30, 2001. In addition, SFAS No. 141 required that unamortized negative goodwill related to pre-July 1, 2001 purchases be recognized as a change in accounting principle concurrent with the adoption of SFAS No. 142, "Goodwill and Other Intangible Assets" (SFAS No. 142). At December 31, 2001, AmerGen, an equity-method investee of Generation, had $43 million of negative goodwill, net of accumulated amortization, recorded on its balance sheet. Upon AmerGen's adoption of SFAS No. 141 in January 2002, Generation recognized its proportionate share of income of $22 million ($13 million, net of income taxes) as a cumulative effect of a change in accounting principle.

Exelon adopted SFAS No. 142 as of January 1, 2002. SFAS No. 142 establishes new accounting and reporting standards for goodwill and intangible assets. Other than goodwill, Exelon does not have significant other intangible assets recorded on its consolidated balance sheets. Under SFAS No. 142, goodwill is no longer subject to amortization; however, goodwill is subject to an assessment for impairment using a two-step fair value based test. The first step must be performed at least annually, or more frequently if events or circumstances indicate that goodwill might be impaired and compares the fair value of a 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 compares the carrying amount of the goodwill to the 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, except at the transition date, when the loss is reflected as a cumulative effect of a change in accounting principle.

As of December 31, 2001, Exelon's Consolidated Balance Sheets reflected approximately $5.3 billion in goodwill net of accumulated amortization, including $4.9 billion of net goodwill related to the Merger recorded on ComEd's Consolidated Balance Sheets, with the remainder related to Enterprises. The first step of the transitional impairment analysis indicated that ComEd's goodwill was not impaired but that an impairment did exist with respect to goodwill recorded in Enterprises' reporting units. InfraSource, the energy services business (Exelon Services) and the competitive retail energy sales business (Exelon Energy) were determined to be those reporting units of Enterprises that had goodwill allocated to them. The second step of the analysis, which compared the fair value of each of Enterprises' reporting units' goodwill to the carrying value at December 31, 2001, indicated a total goodwill impairment of $357 million ($243 million, net of income taxes and minority interest). The fair value of the Enterprises' reporting units was determined using discounted cash flow models reflecting the expected range of future cash flow outcomes related to each of the Enterprises reporting units over the life of the investment. These cash flows were discounted to 2002 using a risk-adjusted discount rate. The impairment was recorded as a cumulative effect of a change in accounting principle in the first quarter of 2002.

The changes in the carrying amount of goodwill by reportable segment (see Note 20 - Segment Information) for the year ended December 31, 2002 are as follows:

	Energy Delivery	Enterprises	Total
Balance as of January 1, 2002	$ 4,902	$ 433	$ 5,335
Impairment losses	--	(357)	(357)
Resolution of certain tax matters	21	--	21
Merger severance adjustment	(7)	--	(7)
Balance as of December 31, 2002	$ 4,916	$ 76	$ 4,992

The December 31, 2002, Energy Delivery goodwill relates to ComEd and the remaining Enterprises goodwill relates to the InfraSource and Exelon Services reporting units. Consistent with

SFAS No. 142, the remaining goodwill will be reviewed for impairment on an annual basis, or more frequently if significant events occur that could indicate an impairment exists. ComEd and Enterprises performed an impairment review in the fourth quarter of 2002. Such review was consistent with the review conducted related to the implementation of SFAS No. 142, which required estimates of numerous items with varying degrees of uncertainty, such as discount rates, terminal value earnings multiples, future revenue levels and estimated future expenditure levels for ComEd and Enterprises; load growth and the resolution of future rate proceedings for ComEd; and customer base and construction back logs for Enterprises. These valuations determined the Step I calculated fair value of both ComEd and the Enterprises' units to be in excess of their respective book values at November 1, 2002. Significant changes from the assumptions used in the impairment review could possibly result in a future impairment loss. Illinois legislation provides that reductions to ComEd's common equity resulting from goodwill impairments will not impact ComEd's earnings through 2006 under the earnings provisions of the legislation. See Note 5 - Regulatory Issues for further discussion of ComEd's earnings provisions.

The components of the net transitional impairment loss recognized in the first quarter of 2002 as a cumulative effect of a change in accounting principle are as follows:

Enterprises goodwill impairment (net of income taxes of $103)	$	(254)
Minority interest (net of income taxes of $4)		11
Elimination of AmerGen negative goodwill (net of income taxes of $9)		13
Total cumulative effect of a change in accounting principle	$	(230)

The following tables set forth Exelon's net income and earnings per common share for 2002, 2001, and 2000 adjusted to exclude 2001 and 2000 amortization expense related to goodwill that is no longer being amortized.

	2002	2001	2000
Reported income before cumulative effect of changes in accounting principles	$ 1,670	$ 1,416	$ 562
Cumulative effect of changes in accounting principles	(230)	12	24
Reported net income	1,440	1,428	586
Goodwill amortization	--	155	34
Adjusted net income	$ 1,440	$ 1,583	$ 620
Basic earnings per common share:			
Reported income before cumulative effect of changes in accounting principles	$ 5.18	$ 4.42	$ 2.79
Cumulative effect of changes in accounting principles	(0.71)	0.04	0.12
Reported net income	4.47	4.46	2.91
Goodwill amortization	--	0.48	0.17
Adjusted net income	$ 4.47	$ 4.94	$ 3.08
Diluted earnings per common share:			
Reported income before cumulative effect of changes in accounting principles	$ 5.15	$ 4.39	$ 2.75
Cumulative effect of changes in accounting principles	(0.71)	0.04	0.12
Reported net income	4.44	4.43	2.87
Goodwill amortization	--	0.48	0.17
Adjusted net income	$ 4.44	$ 4.91	$ 3.04

The cessation of the amortization of negative goodwill of AmerGen on January 1, 2002 did not have a material impact on Exelon's reported net income for 2002.

EITF Issue 02-3

In the third quarter of 2002, Exelon and Generation adopted the provision of EITF Issue 02-3, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities" (EITF 02-3) issued by the FASB EITF in June 2002 that requires revenues and energy costs related to energy trading contracts to be presented on a net basis in the income statement. Prior to the adoption, revenues from trading activity were presented in Revenue and the energy costs related to energy trading were presented as either Purchased Power or Fuel expense on Exelon and Generation's Consolidated Statements of Income. For comparative purposes, energy costs related to energy trading have been reclassified in prior periods to revenue to conform to the net basis of presentation required by EITF 02-3. Exelon commenced trading activities in April 2001, as such $207 million of purchased power expense and $15 million of fuel expense, respectively, was reclassified and reflected as a reduction to revenue for the year ended December 31, 2001.

SFAS No. 144

In September 2001, the FASB issued SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets" (SFAS No. 144). Exelon adopted SFAS No. 144 on January 1, 2002. SFAS No. 144 establishes accounting and reporting standards for both the impairment and disposal of long-lived assets. SFAS No. 144 is effective for fiscal years beginning after December 15, 2001 and its provisions are generally applied prospectively. The adoption of SFAS No. 144 had no effect on Exelon's reported financial position, results of operations or cash flows.

SFAS No. 145

In April 2002, the FASB issued SFAS No. 145, "Rescission of FASB Statements No. 4, 44 and 64, Amendment of FASB Statement No. 13, and Technical Corrections" (SFAS No. 145). SFAS No. 145 eliminates SFAS No. 4 "Reporting Gains and Losses from Extinguishment of Debt" and thus allows for only those gains or losses on the extinguishment of debt that meet the criteria of extraordinary items to be treated as such in the financial statements. SFAS No. 145 also amends Statement of Financial Accounting Standards No. 13, "Accounting for Leases" to require sale-leaseback accounting for certain lease modifications that have economic effects that are similar to sale-leaseback transactions. The adoption of SFAS No. 145 required a reclassification of the 2000 extraordinary item of $4 million, net of income taxes, to interest expense; otherwise, it had no effect on Exelon's reported financial position or cash flows.

SFAS No. 133

SFAS No. 133 applies to all derivative instruments and requires that such instruments be recorded on the balance sheet either as an asset or a liability measured at their fair value through earnings, with special accounting permitted for certain qualifying hedges. On January 1, 2001, Exelon adopted SFAS No. 133. Generation recognized a non-cash gain of $12 million, net of income taxes, in earnings and deferred a non-cash gain of $4 million, net of income taxes, in accumulated other comprehensive income and PECO deferred a non-cash gain of $40 million, net of income taxes, in accumulated other comprehensive income.

Nuclear Outage Costs

During the fourth quarter of 2000, as a result of the synchronization of accounting policies with Unicom in connection with the Merger, PECO changed its method of accounting for nuclear outage costs to record such costs as incurred. Previously, PECO accrued these costs over the operating unit cycle. As a result of the change in accounting method for nuclear outage costs, PECO recorded income of $24 million, net of income taxes of $16 million. The change is reported as a cumulative effect of a change in accounting principle on the Consolidated Statements of Income as of December 31, 2000, representing the balance of the nuclear outage cost reserve at January 1, 2000.

SFAS No. 148

In December 2002, the FASB issued SFAS No. 148, "Accounting for Stock-Based Compensation - Transition and Disclosure - an amendment of FASB Statement No. 123" (SFAS No. 148). SFAS No. 148 provides alternative methods of transition for a voluntary change to the fair value based method of accounting for stock-based employee compensation and requires disclosures in both annual and interim financial statements regarding the method of accounting for stock-based compensation and the effect of the method on financial results. SFAS No. 148 is effective for financial statements for fiscal years ending after December 15, 2002. As of December 31, 2002, Exelon has adopted the additional disclosure requirements of SFAS No. 148 and continues to account for its stock-compensation plans under the disclosure only provision of SFAS No. 123.

Changes in Accounting Estimates

Effective July 1, 2002, ComEd decreased its depreciation rates based on a new depreciation study reflecting its significant construction program in recent years, changes in and development of new technologies, and changes in estimated plant service lives since the last depreciation study. The annualized reduction in depreciation expense, based on December 31, 2001 plant balances, is estimated to be approximately $100 million ($60 million, net of income taxes). As a result of the change, net income for 2002 increased approximately $48 million ($29 million, net of income taxes).

Effective April 1, 2001, Generation changed its accounting estimates related to the depreciation and decommissioning of certain generating stations. The estimated service lives were extended by 20 years for three nuclear stations, by periods of up to 20 years for certain fossil stations and by 50 years for a pumped storage station. Effective July 1, 2001, the estimated service lives were extended by 20 years for the remainder of Exelon's operating nuclear stations. These changes were based on engineering and economic feasibility studies performed by Generation considering, among other things, future capital and maintenance expenditures at these plants. The service life extension is subject to Nuclear Regulatory Commission (NRC) approval of an extension of existing NRC operating licenses, which are generally 40 years. The estimated annualized reduction in expense from the change is $132 million ($79 million, net of income taxes).

In April 2002, ComEd changed its accounting estimate related to the allowance for uncollectible accounts based on an independently prepared evaluation of the risk profile of ComEd's customer accounts receivable. As a result of the new evaluation, the allowance for uncollectible accounts reserve was reduced by $11 million in the second quarter of 2002.

In December 2002, PECO changed its accounting estimate related to the allowance for uncollectible accounts based on an independently prepared evaluation of the risk profile of PECO's customer accounts receivable. As a result of the new evaluation, the allowance for uncollectible accounts reserve was reduced by $17 million in the fourth quarter of 2002.

In 2002, Generation increased its allowance for uncollectible accounts by $6 million based on an independently prepared evaluation of the risk profile of Power Team's counterparties. Power Team is the unit within Generation that manages the output of Generation's assets and energy sales to reduce the volatility of Generation's earnings and cash flows.

5. Regulatory Issues

ComEd

Delivery Service Rates. On June 1, 2001, ComEd filed with the ICC to establish delivery service charges for residential customers in preparation for residential customer choice, which began in May 2002. ComEd is authorized to charge customers who purchase electricity from an alternative supplier for the use of its distribution system to deliver that electricity. These delivery service rates are set through proceedings before the ICC based upon, among other things, the operating costs associated with ComEd's distribution system and the capital investment that ComEd has made in its distribution system.

On April 1, 2002, the ICC issued an interim order in ComEd's Delivery Services Rate Case. The interim order is subject to an audit of test year (2000) expenditures, including capital plant expenditures, with a final order to be issued in 2003. The order sets delivery rates for residential customers choosing a new retail electric supplier. The new rates became effective May 1, 2002 when residential customers became eligible to choose their supplier of electricity. Traditional bundled rates paid by customers that retain ComEd as their electricity supplier are not affected by this order. Bundled rates will remain frozen through 2006, as a result of the June 6, 2002 amendments to the Illinois Restructuring Act that extended the freeze on bundled rates for an additional two years. Delivery service rates for non-residential customers are not affected by the order.

In October 2002, the ICC received the report on the audit of the test year expenditures by a consulting firm engaged by the ICC to perform the audit. The consulting firm recommended certain additional disallowances to test year expenditures and rate base levels. ComEd does not expect this matter to have a significant impact on results of operations in 2003, however, the estimated potential investment write-off, before income taxes, could be up to approximately $100 million, if the ICC ultimately determines that all or some portion of ComEd's distribution plant is not recoverable through rates. In 2002, ComEd recorded a charge to earnings, before income taxes, of $12 million representing the estimated minimum probable exposure pursuant to SFAS No. 90, "Regulated Enterprises - Accounting for Abandonments and Disallowances of Plant Costs an Amendment of FASB Statement No. 71." ComEd is in negotiations with several parties to resolve the delivery service case.

Customer Choice. As of December 31, 2002, all ComEd's customers were eligible to choose an alternative electric supplier and non-residential customers can also elect the power purchase option (PPO) that allows the purchase of electric energy from ComEd at market-based prices. ComEd's residential customers became eligible to choose a new electric supplier in May 2002. However, as of December 31, 2002, no alternative supplier had sought approval from the ICC and no electric utilities have chosen to enter the ComEd residential market for the supply of electricity. As of December 31, 2002, approximately 22,700 non-residential customers, representing approximately 26% of ComEd's annual retail kilowatt-hour sales, had elected to purchase their electric energy from an alternate electric supplier or had chosen the power purchase option. Customers who receive energy from an alternative supplier continue to pay a delivery charge. ComEd is unable to predict the long-term impact of customer choice on results of operations.

Rate Reductions and Return on Common Equity Threshold. The Illinois restructuring legislation provided a 15% residential base rate reduction effective August 1, 1998 with an additional 5% residential base rate reduction effective October 1, 2001. ComEd's operating revenues were reduced by approximately $99 million and $24 million in 2002 and 2001, respectively due to the 5% residential rate reduction. Notwithstanding the rate reductions and subject to certain earnings tests, a rate freeze is generally in effect until at least 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 earned return on common equity of a utility during this period 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 the Monthly Treasury Bond Long-Term Average (25 years and above). Earnings for purposes of ComEd's threshold include ComEd's net income calculated in accordance with GAAP and reflect the amortization of regulatory assets and goodwill. As a result of the Illinois legislation, at December 31, 2002, ComEd had a regulatory asset with an unamortized balance of $175 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 at amounts that provide ComEd an earned return on common equity within the Illinois legislation earnings threshold. The earned return on common equity and the threshold return on common equity for ComEd are each calculated on a two-year average basis. ComEd did not trigger the earnings sharing provision in 2002, 2001 or 2000 and does not currently expect to trigger the earnings sharing provisions in the years 2003 through 2006.

PECO

Revenue Neutral Reconciliation Adjustment. As permitted by the Pennsylvania Electric Competition Act, the Pennsylvania Department of Revenue calculated a 2002 Revenue Neutral Reconciliation (RNR) adjustment to the gross receipts tax rate in order to neutralize the impact of electric restructuring on its tax revenues. In January 2002, the PUC approved the RNR adjustment to the gross receipts tax rate collected from customers. Effective January 1, 2002, PECO implemented the change in the gross receipts tax rate. The RNR adjustment increases the gross receipts tax rate, which increased PECO's annual revenues and tax obligations by approximately $50 million in 2002. The RNR adjustment was appealed. The case was remanded to the PUC and in August 2002, the PUC ruled that PECO is properly authorized to recover these costs. In December 2002, the PUC approved the inclusion of the RNR factor in PECO's base rates eliminating the need for an annual filing to obtain approval for recovery.

Customer Choice. The PUC's Final Electric Restructuring Order provided for the phase-in of customer choice of electric generation suppliers (EGS) and as of January 1, 2000, all customers were eligible for customer choice. The Final Restructuring Order also established market share thresholds (MST) to promote competition. The MST requirements provided that, if as of January 1, 2001 and January 1, 2003, respectively, less than 35% and 50% of residential and commercial customers were shopping, the number of customers sufficient to meet the MST shall be randomly selected and assigned to an EGS through a PUC-determined process. For residential and small commercial customers, the threshold measurement is by number of customers. For large commercial customers the measurement is by load. On January 1, 2001, the 35% MST threshold was met for all customer classes as a result of agreements assigning customers to New Power Company (New Power) and Green Mountain as providers of last resort default service. During 2002, PECO experienced an increase in the number of customers selecting or returning to PECO as their EGS and at December 31, 2002, approximately 21% of PECO's residential load, 10% of its small commercial and industrial load and 7% of its large commercial and industrial load were purchasing generation from an alternative generation supplier. Customers who purchase energy from an EGS continue to pay a delivery charge. In January 2003, PECO submitted to the PUC an MST plan to meet the 50% threshold requirement for its small and large commercial customer classes, which was approved on February 6, 2003. According to the approved plan, randomly assigned customers who participated will be switched to winning MST bidders as of their respective meter read dates. Also in February 2003, PECO filed an MST plan for the residential customer classes which is pending PUC approval.

In February 2002, New Power notified PECO of its intent to withdraw from providing Competitive Default Service (CDS) to approximately 180,000 residential customers. As a result of that withdrawal, those CDS customers were returned to PECO in the second quarter of 2002. Pursuant to a tariff filing approved by the PUC, PECO is serving those returned customers at the discount energy rates on generation provided for under the original New Power CDS Agreement for the remaining term of that contract. Subsequently, in the second quarter of 2002, New Power also advised PECO it planned to withdraw from serving all of its customers in Pennsylvania, including approximately 15,000 non-CDS PECO customers. These customers were returned to PECO during the third quarter of 2002.

Rate Reductions and Caps. Under the Final Restructuring Order, retail electric rates were capped at year-end 1996 levels (system-wide average of 9.96 cents/kilowatt hour (kWh)) through June 2005. The Final Restructuring Order required PECO to reduce its retail electric rates by 8% from the 1996 system-wide average rate on January 1, 1999. This rate reduction decreased to 6% on January 1, 2000 until January 1, 2001. The transmission and distribution rate component was capped at a system-wide average rate of 2.98 cents/kWh through June 30, 2005. Additionally, generation rate caps, defined as the sum of the applicable transition charge and energy and capacity charge, will remain in effect through 2010.

On March 16, 2000, the PUC issued an order authorizing PECO to securitize up to an additional $1 billion of its authorized stranded costs recovery. In accordance with the terms of that order, PECO provided its retail customers with rate reductions of $60 million for calendar year 2001 only.

Under a comprehensive settlement agreement in connection with achieving regulatory approval of the Merger, PECO agreed to $200 million in aggregate rate reductions for all customers in Pennsylvania over the period January 1, 2002 through 2005 and extended the rate caps on PECO's retail electric distribution charges through December 31, 2006.

6. Supplemental Financial Information

Supplemental Income Statement Information

	For the Years Ended December 31,		
	2002	2001	2000
Taxes Other Than Income			
Utility (a)	$ 412	$ 342	$ 196
Real estate	149	140	68
Payroll	98	88	41
Other	50	53	17
Total	$ 709	$ 623	$ 322
Other, Net			
Investment income	$ 130	$ 47	$ 64
Gain (loss) on disposition of assets, net	199	4	(19)
Write-down of impaired investments	(41)	(36)	--
AFUDC, equity and borrowed	19	18	3
Reserve for potential plant disallowance	(12)	--	--
Settlement of power purchase agreement	--	--	6
Other	5	46	(1)
Total	$ 300	$ 79	$ 53

(a) Municipal and state utility taxes are also recorded in Revenues on Exelon's Consolidated Statements of Income.

Supplemental Cash Flow Information

	For the Years Ended December 31,		
	2002	2001	2000
Cash paid during the year:			
Interest (net of amount capitalized)	$ 905	$ 963	$ 519
Income taxes (net of refunds)	$ 614	$ 749	$ 272
Non-cash investing and financing activities:			
Regulatory Asset Fair Value Adjustment	$ --	$ 347	$ --
Resolution of Certain Tax Matters and Merger Severance Adjustment	14	--	--
Purchase Accounting Estimate Adjustments	--	(85)	--
Issuance of Exelon Shares for Unicom	--	--	5,310
Capital Lease Obligations	52	--	--
Issuance of InfraSource Stock	--	35	14
Contribution of Land from Minority Interest of Consolidated Subsidiary	12	--	--
Note Issued to Sithe in the Sithe New England Acquisition	534	--	--
Depreciation and amortization:			
Property, plant and equipment	$ 729	$ 697	$ 325
Regulatory assets	472	445	53
Nuclear fuel	374	393	149
Decommissioning	126	144	46
Goodwill	--	155	34
Total Depreciation and Amortization	$ 1,701	$ 1,834	$ 607

Supplemental Balance Sheet Information

	December 31,	
	2002	2001
Investments		
Investment in Sithe	$ 478	$ 700
Direct financing leases	445	427
Energy services and other ventures	167	161
Investment in AmerGen	160	95
Affordable housing projects	88	98
Communication ventures	39	116
Investment in subsidiaries and joint ventures	16	26
Total	$ 1,393	$ 1,623

Prior to the Merger, Unicom 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. Unicom Investments, Inc. 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, Exelon 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 are as follows:

	December 31, 2002	December 31, 2001
Total minimum lease payments	$ 1,492	$ 1,492
Less: Unearned income	1,047	1,065
Net investment in direct financing leases	$ 445	$ 427

	December 31, 2002	December 31, 2001
Regulatory Assets		
Competitive transition charge	$ 4,639	$ 4,947
Recoverable deferred income taxes (see Note 14)	661	701
Nuclear decommissioning costs for retired plants	248	310
Recoverable transition costs	175	277
Reacquired debt costs and interest rate swap settlements	137	112
Non-pension postretirement benefits	65	71
Compensated absences	6	5
Other	7	--
Long-Term Regulatory Assets	5,938	6,423
Deferred energy costs (current asset)	31	56
Total	$ 5,969	$ 6,479

- Competitive Transition Charges (CTC) represent PECO's stranded costs that the PUC determined would be allowed to be recoverable through regulated rates. These costs are related to the deregulation of the generation portion of the electric utility business in Pennsylvania. The unamortized balance of the CTC of $4.6 billion and $4.9 billion as of December 31, 2002 and 2001, respectively, was recorded on our Consolidated Balance Sheets. The CTC includes Intangible Transition Property sold to PECO Energy Transition Trust, a wholly owned 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%.
- Nuclear decommissioning costs for retired plants - recovery is provided through ComEd's current regulated rates and is expected to be fully recovered by the end of 2006.
- Recoverable transition costs - recovery is provided for in regulated rates pursuant to the Illinois Restructuring Act and is expected to be recovered by the end of 2006.
- Reacquired debt costs and interest rate swap settlements - recoverable gains and losses on reacquired debt are deferred and amortized over the rate-regulatory period, which is 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.

The regulatory assets related to the nuclear decommissioning costs and deferred income taxes 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 loss on reacquired debt and recoverable transition costs is provided for through regulated revenue sources that are based on the pre-open access cost of service. Therefore, they are earning a rate of return.

	December 31, 2002	December 31, 2001
Accrued Expenses		
Taxes Accrued	$ 420	$ 91
Interest Accrued	307	299
Other Accrued Expenses	584	745
Total	$ 1,311	$ 1,135

7. Earnings Per Share

Diluted earnings per share are calculated by dividing net income by the weighted average shares of common stock outstanding including shares issuable upon exercise of stock options outstanding under Exelon's stock option plans considered to be common stock equivalents. The following table shows the effect of these stock options on the weighted average number of shares outstanding used in calculating diluted earnings per share (in millions):

	2002	2001	2000
Average Common Shares Outstanding	322	320	202
Assumed Exercise of Stock Options	3	2	2
Average Dilutive Common Shares Outstanding	325	322	204

Stock options not included in average common shares used in calculating diluted earnings per share due to their antidilutive effect were approximately five million, five million and 30,000 for 2002, 2001 and 2000, respectively.

8. Accounts Receivable

Accounts Receivable -- Customer at December 31, 2002 and 2001 included unbilled operating revenues of $442 million and $438 million, respectively. The allowance for uncollectible accounts at December 31, 2002 and 2001 was $132 million and $213 million, respectively.

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 2005. At December 31, 2002, PECO had sold a $225 million interest in accounts receivable, consisting of a $164 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," and a $61 million interest in special-agreement accounts receivable which was accounted for as a long-term note payable (see Note 13 - Long-Term Debt). 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, 2002 and 2001, PECO met this requirement and was not required to make any cash deposits.

9. Property, Plant, and Equipment

A summary of property, plant and equipment by classification as of December 31, 2002 and 2001 is as follows:

Asset Category	2002	2001
Electric-Transmission and Distribution	$ 10,980	$ 10,156
Electric-Generation	5,678	4,344
Gas	1,319	1,281
Common	404	399
Nuclear Fuel	3,112	2,681
Construction Work in Progress	2,783	1,294
Other Property, Plant and Equipment	1,628	1,371
Total Property, Plant and Equipment	25,904	21,526
Less Accumulated Depreciation (including accumulated amortization of nuclear fuel of $2,212 and $1,838 as of December 31, 2002 and 2001, respectively)	8,770	7,735
Property, Plant and Equipment, net	$ 17,134	$13,791

10. Jointly Owned Electric Utility Plant

Exelon's undivided ownership interests in jointly owned electric plant at December 31, 2002 and 2001 were as follows:

	Production Plant					
December 31, 2002	Peach Bottom	Salem	Keystone	Conemaugh	Quad Cities	Transmission and Other Plant
Operator	Generation	PSE&G	Reliant	Reliant	Generation	Various Co.
Participating Interest	50%	42.59%	20.99%	20.72%	75%	21 to 44%
Exelon's Share:						
Plant	$ 417	$ 44	$ 131	$ 214	$ 171	$ 58
Accumulated Depreciation	243	12	117	145	4	22
Construction Work in Progress	52	36	28	1	35	--

December 31, 2001	Peach Bottom	Salem	Keystone	Conemaugh	Quad Cities	Transmission and Other Plant
	Production Plant					
Operator	Generation	PSE&G	Reliant	Reliant	Generation	Various Co.
Participating Interest	50%	42.59%	20.99%	20.72%	75%	21 to 44%
Exelon's Share:						
Plant	$ 387	$ 12	$ 121	$ 193	$ 96	$ 66
Accumulated Depreciation	220	4	98	124	10	25
Construction Work in Progress	13	53	13	12	52	1

Exelon's undivided ownership interests are financed with Exelon funds and, when placed in service, all operations are accounted for as if such participating interests were wholly owned facilities. Direct expenses of the jointly owned plants are included in the corresponding operating expenses on the Consolidated Income Statements.

11. Nuclear Decommissioning and Spent Fuel Storage

Exelon has an obligation to decommission its nuclear power plants. Exelon's current estimate of its nuclear facilities' decommissioning cost for its owned nuclear power plants is $7.4 billion in current year (2003) dollars. Based on the extended license lives of the nuclear plants, expenditures are expected to occur primarily when the operating plants are decommissioned, during the period 2029 through 2056. Decommissioning costs are currently recoverable through regulated rates. Under rates in effect through December 31, 2002, Exelon collected approximately $102 million in 2002 from customers. At December 31, 2002, the decommissioning liability, recorded in Accumulated Depreciation and Deferred Credits and Other Liabilities on Exelon's Consolidated Balance Sheets, was $2.8 billion and $1.4 billion, respectively. At December 31, 2001, the decommissioning liability, recorded in Accumulated Depreciation and Deferred Credits and Other Liabilities on Exelon's Consolidated Balance Sheets, was $2.7 billion and $1.4 billion, respectively. In order to fund future decommissioning costs, at December 31, 2002 and 2001, Exelon held $3.1 billion and $3.2 billion, respectively, in trust accounts that are included as Investments in Exelon's Consolidated Balance Sheets at their fair market value. Exelon believes that the amounts being recovered from customers through regulated rates and earnings on nuclear decommissioning trust funds will be sufficient to fully fund its decommissioning obligations.

In connection with the transfer of ComEd's nuclear generating stations to Generation, ComEd asked the ICC to approve the continued recovery of decommissioning costs after the transfer. On December 20, 2000, the ICC issued an order finding that the ICC has the legal authority to permit ComEd to continue to recover decommissioning costs from customers for the six-year term of the power purchase agreements between ComEd and Generation. Under the ICC order, ComEd is permitted to recover $73 million per year from customers for decommissioning for the years 2001 through 2004. In 2005 and 2006, ComEd can recover up to $73 million annually, depending upon the portion of the output of the former ComEd nuclear stations that ComEd purchases from Generation. Under the ICC order, subsequent to 2006, there will be no further recoveries of decommissioning costs from customers. The ICC order also provides that any surplus funds after the nuclear stations are decommissioned must be refunded to customers. The amount of recovery in the ICC order is less than the $84 million annual amount ComEd recovered in 2000. The ICC order has been upheld on appeal in the Illinois Appellate Court and the Illinois Supreme Court has declined to review the Appellate Court's decision.

To account for the effects of the ICC order, in the first quarter of 2001 ComEd reduced its nuclear decommissioning regulatory asset to $372 million, reflecting the reduction in expected probable future recoveries from customers through 2006. The reduction in the regulatory asset in the amount of $347 million was recorded as an adjustment to the initial Merger purchase price allocation and resulted in a corresponding increase in goodwill. Also, ComEd recorded an obligation to Generation of approximately

$440 million representing ComEd's legal requirement to remit funds to Generation for the remaining regulatory asset amount of $372 million upon collection from customers, and for collections from customers prior to the establishment of external decommissioning trust funds in 1989 to be remitted to Generation for deposit into the decommissioning trusts through 2006. Unrealized gains and losses on decommissioning trust funds (based on the market value of the assets on the Merger date, in accordance with purchase accounting) had previously been recorded in accumulated depreciation or regulatory assets. As a result of the transfer of the ComEd nuclear plants to Generation and the ICC order limiting the regulated recoveries of decommissioning costs, net unrealized losses of $23 million (net of income taxes) at that date were reclassified to accumulated other comprehensive income. All subsequent realized gains and losses on these decommissioning trust funds' assets are based on the cost basis of the trust fund assets established on the Merger date and are reflected in Other Income and Deductions in Exelon's Consolidated Statements of Income.

Nuclear decommissioning costs associated with the nuclear generating stations formerly owned by PECO continue to be recovered currently through rates charged by PECO to regulated customers. These amounts are remitted to Generation as allowed by the PUC. Under an agreement effective September 2001, PECO remits $29 million per year to Generation related to nuclear decommissioning cost recovery.

On December 31, 2002, PECO filed with the PUC for an annual increase in its decommissioning cost recovery of $20 million effective June 1, 2004. The filing is consistent with provisions in the Restructuring Settlement and the Merger Settlement which require PECO to update the cost of decommissioning every five years. The additional amount requested is expected to be reduced as it does not reflect pending life extensions at Peach Bottom. The approval of the life extensions is expected by mid-2003.

Under the Nuclear Waste Policy Act of 1982 (NWPA), the U.S. Department of Energy (DOE) is responsible for the selection and development of repositories for, and the disposal of, spent nuclear fuel (SNF) and high-level radioactive waste. ComEd and PECO, as required by the NWPA, each signed contracts with the DOE (Standard Contract) to provide for disposal of SNF from their respective nuclear generating stations. In accordance with the NWPA and the Standard Contract, ComEd and PECO pay the DOE one mill ($.001) per kilowatt-hour of net nuclear generation for the cost of nuclear fuel long-term storage and disposal. This fee may be adjusted prospectively in order to ensure full cost recovery. The NWPA and the Standard Contract 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 2010. This extended delay in SNF acceptance by the DOE has led to Exelon's adoption of dry storage at its Dresden, Quad Cities and Peach Bottom Units and its consideration of dry storage at other units.

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 August 30, 2002, after taking certain damages related to discovery, ComEd filed briefs in response to the DOE's motions. The Court has postponed the time for the DOE to file reply briefs while it entertains additional DOE discovery motions. This litigation was assumed by Generation in the corporate restructuring.

In July 2000, PECO entered into an agreement 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 Contract. Under that agreement, the DOE agreed to provide PECO with credits against PECO's future contributions to the Nuclear Waste Fund over the next ten years to compensate PECO for SNF storage costs incurred as a result of the DOE's breach of the contract. The agreement also provides 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 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 agreement providing for credits to PECO against nuclear waste fund payments on the ground 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 agreement violates the NWPA and therefore is null and void. The Court did not hold that the agreement 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 this Amendment. That provision further provides 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 Contract would remain in effect and the parties would return to pre-Amendment status. Pursuant to Article XIV(I), Generation has begun negotiations with the DOE and those negotiations are ongoing. Under the agreement, Generation has received approximately $40 million in credits against contributions to the nuclear waste fund.

In April 2001, an individual filed suit against the DOE with the United States District Court for the Middle District of Pennsylvania seeking to invalidate the agreement on the grounds that the DOE has violated the National Environmental Policy Act and the Administrative Procedure Act. PECO intervened as a defendant and moved to dismiss the complaint. Generation assumed the defense in restructuring. On September 30, 2002, the Court granted Generation's motion and dismissed the lawsuit on the ground that the Court did not have jurisdiction over the matter.

The Standard Contract with the DOE also requires that PECO and ComEd pay the DOE a one-time fee applicable to nuclear generation through April 6, 1983. PECO's fee has been paid. Pursuant to the Standard Contract, 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, 2002, the unfunded liability for the one-time fee with interest was $858 million. The liabilities for spent nuclear fuel disposal costs, including the one-time fee, were transferred to Generation as part of the corporate restructuring.

12. Notes Payable

	2002	2001	2000
Average borrowings	$ 337	$ 193	$ 186
Average interest rates, computed on daily basis	1.94%	4.01%	6.62%
Maximum borrowings outstanding	$ 783	$ 599	$ 500
Average interest rates, at December 31	1.88%	2.63%	7.18%

Exelon, ComEd, PECO and Generation entered into a $1.5 billion unsecured revolving credit facility on November 22, 2002 with a group of banks. Under the credit facility, each borrower may borrow up to a designated sublimit amount on a revolving credit basis through November 20, 2003. This credit facility includes a term-out option that allows any outstanding borrowings at the end of the revolving credit period to be repaid on November 21, 2004. This credit facility is used principally to support the commercial paper programs of Exelon, ComEd, PECO and Generation. At December 31, 2002, the amount of commercial paper outstanding was $681 million which does not include $267 million that has been classified as long-term debt. At December 31, 2001, the amount of commercial paper outstanding was $360 million. Interest rates on the advances under the credit facility are based on the London Interbank Offering Rate (LIBOR) as of the date of the advance.

13. Long-Term Debt

	Rates	Maturity Date	December 31, 2002	2001
Securitized Long-Term Debt				
ComEd Transitional Trust Notes				
Series 1998-A:	5.39%-5.74%	2003-2008	$ 2,040	$ 2,380
PETT Bonds Series 1999-A:				
Fixed rates	5.63%-6.13%	2003-2008 (a)	2,426	2,577
Floating rates	1.48%-1.55%	2004-2007 (a)	274	310
PETT Bonds Series 2000-A:	7.63%-7.65%	2009 (a)	750	890
PETT Bonds Series 2001:	6.52%	2010 (a)	805	805
Other Long-Term Debt				
First and Refunding Mortgage Bonds (b) (c):				
Fixed rates	4.4%-9.875%	2003-2023	3,614	3,942
Floating rates	1.08%-1.41%	2012-2013	254	154
Notes payable and other	6.40%-9.20%	2003-2020	2,393	2,651
SBG Facility	6.37%(d)	2007	1,036	--
Pollution control notes:				
Fixed rates	5.2%-6.95%	2007-2034	199	44
Floating rates	1.05%-1.50%	2009-2034	456	583
Notes payable - accounts receivable agreement	1.42%	2005	61	55
Sinking fund debentures	3.125%-4.75%	2004-2011	20	23
Commercial Paper (e)	1.88% (f)	2003	267	--
Total Long-Term Debt (g)			14,595	14,414
Unamortized debt discount and premium, net			(107)	(129)
Fair value hedge carrying value adjustment			41	--
Due within one year			(1,402)	(1,406)
Long-Term Debt			$ 13,127	$ 12,879

(a) The maturity date represents the expected final payment date which is the date when all principal and interest of the related class of transition bonds is expected to be paid in full in accordance with the expected amortization schedule for the applicable class. The date when all principal and interest must be paid in full for the PETT Bonds Series 1999-A, 2000-A and 2001-A are 2003 through 2009, 2010 and 2010, respectively. The current portion of transition bonds is based upon the expected maturity date.

(b) Utility plant of ComEd and PECO is subject to the liens of their respective mortgage indentures. (c) Includes first mortgage bonds issued under the ComEd and PECO mortgage indentures securing pollution control notes.

(d) The rate for the SBG Facility is stated as an average rate. Under the terms of the SBG Facility, SBG is required to effectively fix the interest rate on 50% of the borrowings under the facility through its maturity in 2007. The SBG Facility is subject to a variable rate based on the LIBOR rate plus a margin of 1.375%, however, through the required interest rate swaps, SBG has effectively fixed the LIBOR component of the interest rate at 5.73% on 83% of the debt balance as of December 31, 2002.

(e) Classified as long-term at December 31, 2002 since it was refinanced with long-term debt in January 2003.

(f) Average interest rate of commercial paper outstanding at December 31, 2002.

(g) Long-term debt maturities in the period 2003 through 2007 and thereafter are as follows:

2003	$ 1,669
2004	962
2005	1,313
2006	1,273
2007	1,172
Thereafter	8,206
Total	$14,595

2003 maturities include $267 million of commercial paper classified as long-term debt (see Note 23 - Subsequent Events).

In 2002, ComEd issued $700 million of long-term debt primarily consisting of the issuance of $600 million of 6.15% First Mortgage Bonds, Series 98, due March 15, 2012 and the issuance of $100 million of Illinois Development Finance Authority floating-rate Pollution Control Revenue Refunding Bonds, Series 2002 due April 15, 2013. In 2002, ComEd redeemed or paid at maturity $1,540 million of long-term debt primarily consisting of the redemption of $100 million of 7.25% Illinois Development Finance Authority Pollution Control Revenue Refunding Bonds, Series 1991 due June 1, 2011, the redemption of $200 million of 8.625% First Mortgage Bonds, Series 81, due February 1, 2022, the redemption of $200 million of 8.5% First Mortgage Bonds, Series 84 due July 15, 2022, the payment at maturity of $200 million of 7.375% First Mortgage Bonds, Series 85, due September 15, 2002, the redemption of $200 million of 8.375% First Mortgage Bonds, Series 86, due September 15, 2022, the payment at maturity of $200 million of variable rate senior notes due September 30, 2002, the payment at maturity of $100 million of 9.17% medium-term notes due October 15, 2002, and the retirement of $340 million in transitional trust notes.

In 2002, Generation exchanged $700 million of 6.95% Senior Notes issued in 2001 for notes which are registered under the Securities Act. ComEd exchanged $600 million of 6.15% First Mortgage Bonds, Series 98, due March 15, 2012, for bonds which are registered under the Securities Act. PECO exchanged $250 million of 5.95% private placement First and Refunding Mortgage Bonds, due November 1, 2011, for bonds which are registered under the Securities Act. The exchange bonds are identical to the outstanding bonds except for the elimination of certain transfer restrictions and registration rights pertaining to the outstanding bonds. ComEd, PECO and Generation did not receive any cash proceeds from issuance of the exchange bonds.

In 2002 and 2001, ComEd entered into forward starting interest rate swaps with an aggregate notional amount of $830 million and $250 million, respectively, to manage interest rate exposure associated with anticipated debt issuance. In 2002, forward starting interest rate swaps with an aggregate notional amount of $450 million were settled with net proceeds to counterparties of $10 million that has been deferred in regulatory assets and is being amortized over the life of the First Mortgage Bonds as an increase to interest expense.

In 2002 and 2001, ComEd entered into interest rate swap agreements with a notional amount of $250 million and $235 million, respectively, to effectively convert fixed rate debt to floating rate debt.

In 2002, PECO issued $225 million of 4.75% First and Refunding Mortgage Bonds, due October 1, 2012. This bond issuance repaid commercial paper that was used to pay $222 million of First and Refunding Mortgage Bonds at maturity with a weighted average interest rate of 7.30%. In connection with the issuance of the First and Refunding Mortgage Bonds, PECO settled forward starting interest rate swaps in the aggregate notional amount of $200 million resulting in a $5 million pre-tax loss recorded in other comprehensive income, which is being amortized over the expected remaining life of the related debt.

In 2001, ComEd redeemed $196 million of 9.875% First Mortgage Bonds, Series 75, due June 15, 2020 and retired $340 million in transitional trust notes.

In 2001, PECO Energy Transition Trust (PETT), a Delaware business trust and a wholly owned subsidiary of PECO, refinanced $805 million of floating rate Series 1999-A Transition Bonds through the issuance by PETT of fixed-rate transition bonds (Series 2001-A Transition Bonds). The 2001-A Transition Bonds are non-callable, fixed rate securities with an interest rate of 6.52%. The Series 2001-A Transition Bonds have an expected final payment date of September 1, 2010 and a termination date of December 31, 2010. In connection with this refinancing, PECO settled $318 million of forward starting interest rate swaps resulting in a $6 million gain which is reflected in other income and deductions due to the transaction no longer being probable. Also, in connection with this refinancing, PECO settled a portion of the interest rate swaps and the remaining portion of the forward starting interest rate swaps resulting in gains of $25 million, which were deferred and are being amortized over the expected remaining lives of the related debt.

In 1999, PECO entered into treasury forwards associated with the anticipated issuance of the Series 2000-A Transition Bonds. On May 2, 2000, these instruments were settled with net proceeds to the counterparties of $13 million that has been deferred and is being amortized over the life of the Series 2000-A Transition Bonds as an increase to interest expense.

In 1998, PECO entered into treasury forwards and forward starting interest rate swaps to manage interest rate exposure associated with the anticipated issuance of the Series 1999-A Transition Bonds. On March 18, 1999, these instruments were settled with net proceeds of $80 million to PECO that were deferred and are being amortized over the life of the Series 1999-A Transition Bonds as a reduction of interest expense.

At December 31, 2002 and 2001, the aggregate unamortized net gain on the settlement of the PECO swap transactions was $36 million and $55 million, respectively, recorded in Other Comprehensive Income.

ComEd prepayment premiums of $24 million, and net unamortized premiums, discounts and debt issuance expenses of $3 million, and prepayment premiums of $39 million, offset by unamortized issuance premiums of $17 million associated with the early retirement of debt in 2002 and 2001, respectively, have been deferred in regulatory assets and will be amortized to interest expense over the life of the related new debt issuance consistent with regulatory recovery. In 2000, PECO incurred charges aggregating $6 million ($4 million, net of tax) for prepayment premiums and the write-offs of unamortized deferred financing costs associated with the early retirement of debt that have been recorded in interest expense.

14. Income Taxes

Income tax expense (benefit) is comprised of the following components:

	For the Years Ended December 31,		
	2002	2001	2000
Included in operations:			
Federal			
Current	$ 624	$ 880	$ 161
Deferred	250	(61)	163
Investment tax credit amortization	(15)	(14)	(15)
State			
Current	96	119	--
Deferred	43	7	30
	$ 998	$ 931	$ 339
Included in cumulative effect of changes in accounting principles:			
Federal			
Deferred	$ (87)	$ 6	$ 13
State			
Deferred	(3)	2	3
	$ (90)	$ 8	$ 16

The effective income tax rate varies from the U.S. Federal statutory rate principally due to the following:

	For the Years Ended December 31,		
	2002	2001	2000
U.S. Federal statutory rate	35.0%	35.0%	35.0%
Increase (decrease) due to:			
Property basis differences	(0.4)	(0.2)	0.1
State income taxes, net of Federal income tax benefit	3.2	3.4	2.1
Amortization of investment tax credit	(0.4)	(0.5)	(1.6)
Amortization of goodwill	--	1.9	0.9
Dividends on PECO Preferred Stock	0.1	0.2	0.4
Other, net	(0.1)	(0.1)	0.7
Effective income tax rate	37.4%	39.7%	37.6%

The tax effects of temporary differences giving rise to significant portions of Exelon's deferred tax assets and liabilities as of December 31, 2002 and 2001 are presented below:

	2002	2001
Deferred tax liabilities:		
Plant basis difference	$ 4,710	$ 4,630
Deferred gain on sale of plants	860	872
Deferred investment tax credit	212	222
Deferred debt refinancing costs	96	44
Tax deductible goodwill	--	2
Unrealized gain on derivative financial instruments	--	34
Total deferred tax liabilities	5,878	5,804
Deferred tax assets:		
Decommissioning and decontamination obligations	(607)	(573)
Deferred pension and postretirement obligations	(911)	(382)
Tax deductible goodwill	(95)	--
Unrealized loss on derivative financial instruments	(60)	--
Other, net	(208)	(194)
Total deferred tax assets	(1,881)	(1,149)
Deferred income taxes (net) on the balance sheet	$ 3,997	$ 4,655

In accordance with regulatory treatment of certain temporary differences, Exelon has recorded a regulatory asset for recoverable deferred income taxes, pursuant to SFAS No. 109, "Accounting for Income Taxes," of $661 million and $701 million at December 31, 2002 and 2001, respectively. These recoverable deferred income taxes include the deferred tax effects associated principally with liberalized depreciation accounted for in accordance with the ratemaking policies of the ICC and PUC, as well as the revenue impacts thereon, and assume continued recovery of these costs in future rates.

Exelon's predecessor entities, Unicom and PECO, have years that are under review at the audit or appeals level of the Internal Revenue Service (IRS) and certain state authorities. These reviews by the governmental taxing authorities are not expected to have an adverse impact on the financial condition or result of operations at Exelon.

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 of December 31, 2002, a deferred tax liability of approximately $860 million related to the fossil plant sale is reflected in Deferred Income Taxes on Exelon's Consolidated Balance Sheets. ComEd's management believes an adequate reserve for interest has been established in the event that such positions are not sustained. Changes in IRS interpretations of existing tax authority or challenges to ComEd's positions could have the impact of accelerating future income tax payments and increasing interest expense above amounts reserved related to the deferred tax gain that becomes current. The Federal tax returns covering the period of the 1999 fossil plant sale are anticipated to be under IRS audit beginning in 2003. Final resolution of this matter is not anticipated for several years.

As of December 31, 2002 and 2001, Exelon had recorded valuation allowances of $13 million and $2 million, respectively.

15. Retirement Benefits

Exelon sponsors defined benefit pension plans and postretirement welfare benefit plans applicable to essentially all ComEd, PECO, Generation and Business Services Company (BSC) employees and certain employees of Enterprises. In 2001, Exelon consolidated the former Unicom and PECO plans into Exelon plans. Essentially all management employees, and electing union employees, hired on or after January 1, 2001 participate in newly established cash balance pension plans. Approximately 4,700 management employees who were active participants in the former Unicom and PECO pension plans on December 31, 2000, and remained employed by Exelon on January 1, 2002 elected to transfer to the cash balance plan. Benefits under Exelon's pension plans generally reflect each employee's compensation, years of service and age at retirement. Funding is based upon actuarially determined contributions that take into account the amount deductible for income tax purposes and the minimum contribution required under the Employee Retirement Income Security Act of 1974, as amended. The following tables provide a reconciliation of benefit obligations, plan assets and funded status of the plans.

	Pension Benefits		Other Postretirement Benefits	
	2002	2001	2002	2001
Change in benefit obligation:				
Net benefit obligation at beginning of year	$ 7,101	$ 6,695	$ 2,331	$ 2,275
Service cost	95	94	57	42
Interest cost	525	498	160	161
Plan participants' contributions	--	--	8	4
Plan amendments	120	44	--	(191)
Actuarial (gain)/loss	514	254	155	173
Curtailments/Settlements	--	(38)	--	--
Special accounting costs	4	48	--	3
Gross benefits paid	(505)	(494)	(156)	(136)
Net benefit obligation at end of year	$ 7,854	$ 7,101	$ 2,555	$ 2,331
Change in plan assets:				
Fair value of plan assets at beginning of year	$ 6,279	$ 7,000	$ 1,132	$ 1,188
Actual return on plan assets	(581)	(265)	(125)	(14)
Employer contributions	202	38	73	90
Plan participants' contributions	--	--	8	4
Gross benefits paid	(505)	(494)	(156)	(136)
Fair value of plan assets at end of year	$ 5,395	$ 6,279	$ 932	$ 1,132
Funded status at end of year:	$ (2,459)	$ (822)	$ (1,623)	$ (1,199)
Miscellaneous adjustment	(3)	--	--	--
Unrecognized net actuarial (gain)/loss	2,118	397	793	440
Unrecognized prior service cost	211	108	(149)	(191)
Unrecognized net transition obligation (asset)	(11)	(17)	102	103
Net amount recognized at end of year	$ (144)	$ (334)	$ (877)	$ (847)
Amounts recognized in statements of financial position:				
Prepaid benefit cost	$ 145	$ --	$ --	$ --
Accrued benefit cost	(289)	(334)	(877)	(847)
Additional minimum liability	(1,815)	--	--	--
Intangible asset	211	--	--	--
Accumulated other comprehensive income	1,604	--	--	--
Net amount recognized at end of year	$ (144)	$ (334)	$ (877)	$ (847)

	Pension Benefits 2002	Pension Benefits 2001	Pension Benefits 2000	Other Postretirement Benefits 2002	Other Postretirement Benefits 2001	Other Postretirement Benefits 2000
Weighted-average assumptions as of December 31,						
Discount rate	6.75%	7.35%	7.60%	6.75%	7.35%	7.60%
Expected return on plan assets	9.50%	9.50%	9.50%	8.80%	8.80%	8.80%
Rate of compensation increase	4.00%	4.00%	4.30%	4.00%	4.00%	4.30%
Health care cost trend on covered charges	N/A	N/A	N/A	8.5% decreasing to ultimate trend of 4.5% in 2008	10.00% decreasing to ultimate trend of 4.5% in 2008	7.00% decreasing to ultimate trend of 5.0% in 2005

	Pension Benefits 2002	Pension Benefits 2001	Pension Benefits 2000	Other Postretirement Benefits 2002	Other Postretirement Benefits 2001	Other Postretirement Benefits 2000
Components of net periodic benefit cost (benefit):						
Service cost	$ 95	$ 94	$ 39	$ 57	$ 42	$ 24
Interest cost	525	498	219	160	161	83
Expected return on assets	(628)	(625)	(316)	(93)	(99)	(34)
Amortization of:						
Transition obligation (asset)	(4)	(4)	(4)	10	10	12
Prior service cost	16	9	7	(37)	(9)	--
Actuarial (gain) loss	--	(25)	(26)	6	1	--
Curtailment charge (credit)	--	(12)	(12)	--	9	24
Settlement charge (credit)	--	(9)	(16)	--	--	--
Net periodic benefit cost (benefit)	$ 4	$ (74)	$ (109)	$ 103	$ 115	$ 109
Special accounting costs	$ 4	$ 48	$ 217	$ --	$ 3	$ 48

Sensitivity of retiree welfare results	
Effect of a one percentage point increase in assumed health care cost trend	
on total service and interest cost components	$ 33
on postretirement benefit obligation	$ 302
Effect of a one percentage point decrease in assumed health care cost trend	
on total service and interest cost components	$ (27)
on postretirement benefit obligation	$ (252)

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.

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. The market value of plan assets has been affected by sharp declines in the equity market since the third quarter of 2000. As a result, at December 31, 2002, Exelon was required to recognize an additional minimum liability and an intangible asset as prescribed by SFAS No. 87 "Employers' Accounting for Pensions." The liability was recorded as a reduction to shareholders' equity, and the equity will be restored to the balance sheet in future periods when the fair value of plan assets exceeds the accumulated benefit obligations. The amount of the reduction to shareholders' equity (net of income taxes) in 2002 was $1.0 billion. The recording of this reduction did not affect net income or cash flow in 2002 or compliance with debt covenants.

Special accounting costs of $4 million in 2002 and $48 million in 2001 represent accelerated separation and enhancement benefits provided to PECO employees expected to be terminated as a result of the Merger. Special accounting costs in 2000 of $217 million represented PECO's accelerated separation and enhancement benefits of $96 million and ComEd's accelerated liability increase of $121 million inclusive of $96 million for separation benefits and $25 million for plan enhancements.

Exelon provides certain health care and life insurance benefits for retired employees. In 2001, Exelon adopted an amendment to the former Unicom postretirement medical benefit plan that changed the eligibility requirement of the plan to cover only employees who retire with 10 years of service after age 45 rather than with 10 years of service and having attained the age of 55. Welfare benefits for active employees are provided by several insurance policies or self-funded plans whose premiums or contributions are based upon the benefits paid during the year.

Exelon sponsors savings plans for the majority of its employees. The plans allow employees to contribute a portion of their pretax 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 $63 million, $57 million and $17 million in 2002, 2001 and 2000, respectively.

16. Preferred Securities of Subsidiaries

Preferred and Preference Stock

At December 31, 2002 and 2001, cumulative Preferred Stock of PECO, no par value, consisted of 15,000,000 shares authorized and the amounts set forth below:

		December 31,			
	Current Redemption Price(a)	2002	2001	2002	2001
		Shares Outstanding		Dollar Amount	
Series (without mandatory redemption)					
$4.68	$ 104.00	150,000	150,000	$ 15	$ 15
$4.40	112.50	274,720	274,720	27	27
$4.30	102.00	150,000	150,000	15	15
$3.80	106.00	300,000	300,000	30	30
$7.48	(b)	500,000	500,000	50	50
		1,374,720	1,374,720	137	137
Series (with mandatory redemption)					
$6.12 (c)		--	185,400	--	19
Total preferred stock		1,374,720	1,560,120	$ 137	$ 156

(a) Redeemable, at the option of PECO, at the indicated dollar amounts per share, plus accrued dividends.
(b) None of the shares of this series is subject to redemption prior to April 1, 2003.
(c) PECO made the annual sinking fund payments of $18.5 million on August 1, 2002 and August 1, 2001. At December 31, 2000, shares and principal outstanding were 370,800 and $37 million, respectively.

At December 31, 2002 and 2001, ComEd Preferred Stock and ComEd Preference Stock consisted of 850,000 and 6,810,451 shares authorized, respectively, none of which were outstanding.

Company Obligated Mandatorily Redeemable Preferred Securities

At December 31, 2002 and 2001, subsidiary trusts of PECO and ComEd had outstanding the following preferred securities:

	Mandatory Redemption Date	Distribution Rate	Liquidation Value	December 31, 2002	2001	2002	2001
				Trust Securities Outstanding		Dollar Amount	
PECO Energy Capital Trust II	2037	8.00%	$ 25	2,000,000	2,000,000	$ 50	$ 50
PECO Energy Capital Trust III	2028	7.38%	1,000	78,105	78,105	78	78
Total				2,078,105	2,078,105	$ 128	$ 128
ComEd Financing I	2035	8.48%	$ 25	8,000,000	8,000,000	$ 200	$ 200
ComEd Financing II	2027	8.50%	1,000	150,000	150,000	150	150
Unamortized Discount						(20)	(21)
Total				8,150,000	8,150,000	$ 330	$ 329

The securities issued by the PECO trusts represent Company Obligated Mandatorily Redeemable Preferred Securities of a Partnership (COMRPS) having a distribution rate and liquidation value equivalent to the trust securities. The COMRPS are the sole assets of these trusts and represent limited partnership interests of PECO Energy Capital, L.P. (Partnership), a Delaware limited partnership. Each holder of a trust's securities is entitled to withdraw the corresponding number of COMRPS from the trust in exchange for the trust securities so held. Each series of COMRPS is supported by PECO's deferrable interest subordinated debentures, held by the Partnership, which bear interest at rates equal to the distribution rates on the related series of COMRPS.

ComEd Financing I and ComEd Financing II are wholly owned subsidiary trusts of ComEd. Each of ComEd trust's sole assets are subordinated deferrable interest securities issued by ComEd bearing interest rates equivalent to the distribution rate of the related trust security.

The preferred securities issued by each of ComEd Financing I and ComEd Financing II have no voting privileges, except (i) for the right to approve a merger, consolidation or other transaction involving the applicable trust that would result in certain United States Federal income tax consequences to that trust, (ii) with respect to certain amendments to the applicable trust agreement, (iii) for certain voting privileges that arise upon an event of default under the applicable trust agreement or (iv) with respect to certain amendments to the related ComEd guarantee agreement.

The interest expense on the debentures and deferrable interest securities is included in Distributions on Preferred Securities of Subsidiaries in the Consolidated Statements of Income and is deductible for income tax purposes.

17. Common Stock

At December 31, 2002 and 2001, common stock without par value consisted of 600,000,000 and 600,000,000 shares authorized and 323,312,586 and 321,006,904 shares outstanding, respectively.

Stock Repurchase

In January 2000, in connection with the Merger Agreement, PECO entered into a forward purchase agreement to purchase $500 million of its common stock from time to time. Settlement of this forward purchase agreement was, at PECO's election, on a physical, net share or net cash basis. In May 2000, PECO utilized a portion of the proceeds from the securitization of its stranded cost recovery to physically settle this agreement, resulting in the repurchase of 12 million shares of common stock for $496 million. In connection with the settlement of this agreement, PECO received $1 million in accumulated dividends on the repurchased shares and paid $6 million of interest.

Stock-Based Compensation Plans

Exelon maintains a Long-Term Incentive Plan (LTIP) for certain full-time salaried employees and previously maintained a broad-based incentive program for certain other employees. The types of long-term incentive awards that have been granted under the LTIP are non-qualified options to purchase shares of Exelon's common stock and common stock awards. At December 31, 2002, there were 13,000,000 options authorized for issuance under the LTIP and 2,000,000 options authorized under the broad-based incentive program.

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 LTIP and the broad-based incentive program become exercisable upon attainment of a target share value and/or time. All options expire 10 years from the date of grant. Information with respect to the LTIP and the broad-based incentive program at December 31, 2002 and changes for the three years then ended, is as follows:

	Shares 2002	Weighted Average Exercise Price (per share) 2002	Shares 2001	Weighted Average Exercise Price (per share) 2001	Shares 2000	Weighted Average Exercise Price (per share) 2000
Balance at January 1	14,039,996	$ 43.96	15,287,859	$ 42.13	6,065,897	$ 31.91
Options granted/assumed	3,938,632	47.12	629,200	66.42	11,089,051 (a)	46.09
Options exercised	(1,821,339)	33.37	(1,695,474)	34.84	(1,725,058)	31.79
Options canceled	(270,299)	53.62	(181,589)	52.64	(142,031)	39.95
Balance at December 31	15,886,990	45.80	14,039,996	43.96	15,287,859	42.13
Exercisable at December 31	10,491,184	43.96	8,006,193	38.75	4,953,942	30.04
Weighted average fair value of options granted during year		$ 13.62		$ 19.59		$ 16.62

(a) Includes 5.3 million options converted in the Merger.

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 2002, 2001 and 2000, respectively:

	2002	2001	2000
Dividend yield	3.3%	3.2%	3.6%
Expected volatility	36.8%	36.8%	36.8%
Risk-free interest rate	4.6%	4.9%	5.9%
Expected life (years)	5.0	5.0	5.0

At December 31, 2002, 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
$10.01-$20.00	560,700	6.14	$ 19.68	560,700	$ 19.68
$20.01-$30.00	926,332	4.64	25.49	926,332	25.49
$30.01-$40.00	4,668,877	7.53	37.87	4,031,683	37.76
$40.01-$50.00	4,844,505	9.39	45.61	1,419,748	42.25
$50.01-$60.00	4,265,109	8.84	59.39	3,159,481	59.47
$60.01-$70.00	621,467	9.03	67.32	393,240	67.28
Total	15,886,990			10,491,184	

Exelon common stock awards under Exelon's LTIP of 316,025 shares were issued during 2000 and 1999. Vesting for the common stock awards is over a period not to exceed 10 years from the grant date. Compensation cost of $14 million associated with these awards is amortized to expense over the vesting period. The related accumulated amortization of $13 million includes amortization expense of approximately $1 million, $5 million and $5 million during 2002, 2001 and 2000, respectively.

Exelon common share awards of 590,074, 426,794 and 159,129 shares were granted under Exelon's LTIP and board compensation plans during 2002, 2001 and 2000, respectively. Total accumulated compensation cost of $60 million is to be accrued to expense over the vesting period of up to 5 years from the grant date. The related accumulated amortization of $37 million includes amortization expense of $20 million, $11 million and $6 million during 2002, 2001 and 2000, respectively.

In June 2001, the Board of Directors of Exelon approved the Employee Stock Purchase Plan (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 3,000,000 shares of Exelon's common stock have been reserved for issuance under the ESPP. Employees' purchases are limited to no more than 125 shares per quarter and no more than $25,000 in fair market value in any plan year. Employees purchased 257,455 and 137,648 shares of Exelon common stock under the ESPP in 2002 and 2001, respectively.

Fund Transfer Restrictions Under PUHCA

Under PUHCA, Exelon is precluded from borrowing or receiving any extension of credit or indemnity from its subsidiaries and can lend, but not borrow, from Exelon's intercompany money pool. Additionally, under PUHCA, Exelon, ComEd, PECO and Generation can pay dividends only from retained, undistributed or current earnings. However, the SEC order granted permission to ComEd, and to Exelon to the extent we receive dividends from ComEd paid from ComEd additional paid-in-capital, to pay up to $500 million in dividends out of additional paid-in capital, although Exelon may not pay dividends out of paid-in capital after December 31, 2002 if its ratio of common equity to total capitalization is less than 30%. At December 31, 2002, Exelon had retained earnings of $2.0 billion, which includes ComEd retained earnings of $577 million, PECO retained earnings of $401 million and Generation undistributed earnings of $924 million. In 2002, Exelon recorded a reduction to shareholders' equity of $1.0 billion related to the minimum pension liability. At December 31, 2002, Exelon's common equity to total capitalization ratio was 32%.

Undistributed Earnings of Equity Method Investments

At December 31, 2002, Exelon had consolidated undistributed earnings of equity method investments of $145 million.

18. Fair Value of Financial Assets and Liabilities

The carrying amounts and fair values of Exelon's financial assets and liabilities as of December 31, 2002 and 2001 were as follows:

	2002		2001	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Non-derivatives:				
Liabilities				
Long-term debt (including amounts due within one year)	$ 14,529	$ 15,950	$ 14,285	$ 14,912
Preferred Securities of Subsidiaries	595	739	613	572
Derivatives:				
Fixed to floating interest rate swaps	41	41	(20)	(20)
Floating to fixed interest rate swaps	(114)	(114)	--	--
Forward starting interest rate swaps	(52)	(52)	(1)	(1)
Energy derivatives	(143)	(143)	78	78

Cash and cash equivalents, customer accounts receivable and trust accounts for decommissioning nuclear plants are recorded at their fair value.

As of December 31, 2002 and 2001, Exelon's carrying amounts of cash and cash equivalents and accounts receivable are representative of fair value because of the short-term nature of these instruments. Fair values of the trust accounts for decommissioning nuclear plants, long-term debt and preferred securities of subsidiaries are estimated based on quoted market prices for the same or similar issues. The fair value of Exelon's interest rate swaps and power purchase and sale contracts is determined using quoted exchange prices, external dealer prices, or internal valuation models which utilize assumptions of future energy prices and available market pricing curves.

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 the Energy Delivery business, their dispersion across many industries.

Exelon has entered into fixed to floating interest rate swaps in the aggregate amount of $485 million of fixed-rate obligations of ComEd. These swaps have been designated as fair-value hedges, as defined in SFAS No. 133 and as such, changes in the fair value of the swap will be recorded in earnings. However, as long as the hedges remain effective and the underlying transaction remains probable, changes in the fair value of the swaps will be offset by changes in the fair value of the hedged liabilities. Any change in the fair value of the hedges as a result of ineffectiveness would be recorded immediately in earnings. The fair market value of these swaps was $41 million at December 31, 2002.

Under the terms of the SBG credit facility, SBG is required to effectively fix the interest rate on 50% of the borrowings under the facility through its maturity in 2007. As of December 31, 2002, Generation has entered into floating to fixed interest rate swap agreements which have effectively fixed the interest rate on $861 million of notional principal, or 83% of borrowings outstanding at December 31, 2002. These swaps have been designated as cash flow hedges under SFAS No. 133, and as such, as long as the hedge remains effective and the underlying transaction remains probable, changes in the fair value of these swaps will be recorded in accumulated other comprehensive income (loss) until earnings are affected by the variability of the cash flows being hedged. The fair market value exposure of these swaps was $92 million at December 31, 2002.

Exelon has also entered into floating to fixed interest rate swaps to manage interest rate exposure associated with the floating rate series of transition bonds issued to securitize PECO's stranded cost recovery. These interest rate swaps were designated as cash flow hedges. These interest rate swaps had an aggregate fair market value exposure of $22 million at December 31, 2002.

PECO also has interest rate swaps in place to satisfy counterparty credit requirements in regards to the floating rate series of transition bonds which are mirror swaps of each other. These swaps are not designated as cash flow hedges, therefore, they are required to be marked-to-market if there is a difference in their values. Since these swaps are offsetting each other, a mark-to-market adjustment is not expected to occur.

During 2002, PECO entered into forward starting interest rate swaps, with an aggregate notional amount of $200 million, in anticipation of the issuance of debt at PECO. These interest rate swaps were designated as cash flow hedges. In connection with bond issuances in 2002, PECO settled these forward starting interest rate swaps resulting in a $5 million pretax loss recorded in other comprehensive income, which is being amortized over the life of the related debt.

During 2002 and 2001, ComEd entered into forward-starting interest rate swaps, with an aggregate notional amount of $830 million and $250 million, respectively, in anticipation of the issuance of debt. In connection with bond issuances in 2002, ComEd settled forward starting interest rate swaps in the aggregate notional amount of $450 million, resulting in a $10 million pre-tax loss recorded as a regulatory asset, which is being amortized over the life of the related debt in interest expense. At December 31, 2002, ComEd had $630 million of forward starting interest rate swaps outstanding. These interest rate swaps, designated as cash flow hedges, had a fair market value exposure of $52 million at December 31, 2002. As it remained probable that the debt issuances, the forecasted future transactions these swaps were hedging, would occur, although the issuances had been delayed, we continued to account for these interest rate swap transactions as hedges. In connection with ComEd's January 22, 2003 issuance of $700 million in First Mortgage Bonds, ComEd settled swaps, in the aggregate notional amount of $550 million, for a payment of $43 million, which will be recorded as a regulatory asset and amortized over the life of the debt issuance.

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.

Exelon utilizes derivatives to manage the utilization of its available generating capacity and 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, Exelon enters into certain energy-related derivatives for trading or speculative purposes.

During 2002 and 2001, Generation recognized net losses of $6 million ($4 million, net of income taxes) and gains of $16 million ($10 million, net of income taxes), respectively, relating to mark-to-market adjustments of certain non-trading power purchase and sale contracts pursuant to SFAS No. 133. Mark-to-market adjustments on non-trading power purchase and sale contracts are reported in fuel and purchased power and mark-to-market adjustments on trading activities are reported as Operating Revenues in the Consolidated Statements of Income. During 2002 and 2001, Generation recognized net losses aggregating $9 million ($6 million, net of income taxes) and net gains aggregating $14 million ($10 million, net of income taxes), respectively, relating to mark-to-market adjustments on derivative instruments entered into for trading purposes. Exelon Generation commenced financial trading in the second quarter of 2001. Gains and losses associated with financial trading are reported as Operating Revenue in the Consolidated Statements of Income. During 2002 and 2001, no amounts were reclassified from accumulated other comprehensive income into earnings as a result of forecasted energy commodity transactions no longer being probable. For 2002, no amounts were reclassified from accumulated other comprehensive income into earnings as a result of forecasted financing transactions no longer being probable. For 2001, a $6 million gain ($4 million, net of income taxes) was reclassified from accumulated other comprehensive income into earnings as a result of forecasted financing transactions no longer being probable.

Enterprises has entered into a limited number of energy commodity derivative contracts in connection with its service of gas customers. While the majority of these contracts qualify as normal purchases and sales or as cash flow hedges under SFAS No. 133, $16 million was recorded as a reduction to fuel expense as a result of contracts being marked to market in 2002. Of this $16 million, $3 million was recorded upon contract settlement and $13 million was recorded as a change in fair value prior to contract settlement. The offset to this $13 million was recorded as an asset on the balance sheet and it is expected that $11 million and $2 million will reverse as fuel expense in 2003 and 2004, respectively. At December 31, 2002, there was a net asset of $20 million on the balance sheet related to Enterprises' mark-to-market contracts. The remaining $7 million of the offset to this asset was recorded in other comprehensive income and is expected to be reclassified to earnings within the next twelve months. Enterprises' counterparties in these contracts are all investment grade, with the exception of Dynegy Inc. (Dynegy), to whom Enterprises has $2 million of exposure.

On January 1, 2001, Exelon recognized a non-cash gain of $12 million, net of income taxes, in earnings and deferred a non-cash gain of $44 million, net of income taxes, in accumulated other comprehensive income, a component of shareholders' equity, to reflect the initial adoption of SFAS No. 133, as amended. SFAS No. 133 must be applied to all derivative instruments and requires that such instruments be recorded in the balance sheet either as an asset or a liability measured at their fair value through earnings, with special accounting permitted for certain qualifying hedges.

As of December 31, 2002, $102 million of deferred net losses on derivative instruments in accumulated other comprehensive income are expected to be reclassified to earnings during the next twelve months. Amounts in accumulated other comprehensive income related to interest rate cash flows are reclassified into earnings when the forecasted interest payment occurs. Amounts in accumulated other comprehensive income related to energy commodity cash flows are reclassified into earnings when the forecasted purchase or sale of the energy commodity occurs. The majority of Exelon's cash flow hedges are expected to settle within the next 4 years.

Exelon would be exposed to credit-related losses in the event of non-performance by the counterparties that issued the derivative instruments. The credit exposure of derivatives contracts is represented by the fair value of contracts at the reporting date. Exelon's interest rate swaps are documented under master agreements. Among other things, these agreements provide for a maximum credit exposure for both parties. Payments are required by the appropriate party when the maximum limit is reached. 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.

Exelon classifies investments in the trust accounts for decommissioning nuclear plants as available-for-sale. The following tables show the fair values, gross unrealized gains and losses and amortized costs bases for the securities held in these trust accounts.

	December 31, 2002			
	Amortized Cost	Gross Unrealized Gains	Gross Unrealized Losses	Estimated Fair Value
Equity securities	$ 1,763	$ 72	$ (482)	$ 1,353
Debt securities				
Government obligations	938	62	--	1,000
Other debt securities	698	32	(30)	700
Total debt securities	1,636	94	(30)	1,700
Total available-for-sale securities	$ 3,399	$ 166	$ (512)	$ 3,053

	December 31, 2001			
	Amortized Cost	Gross Unrealized Gains	Gross Unrealized Losses	Estimated Fair Value
Equity securities	$ 1,666	$ 130	$ (236)	$ 1,560
Debt securities				
Government obligations	882	28	(3)	907
Other debt securities	701	16	(19)	698
Total debt securities	1,583	44	(22)	1,605
Total available-for-sale securities	$ 3,249	$ 174	$ (258)	$ 3,165

Net unrealized losses of $346 million and $84 million were recognized in Accumulated Depreciation, Regulatory Assets and Accumulated Other Comprehensive Income in Exelon's Consolidated Balance Sheets at December 31, 2002 and 2001, respectively.

	For the Years Ended December 31	
	2002	2001
Proceeds from sales	$ 1,612	$ 1,624
Gross realized gains	56	76
Gross realized losses	(86)	(189)

Net realized gains of $2 million and $14 million were recognized in Accumulated Depreciation and Regulatory Assets in Exelon's Consolidated Balance Sheets at December 31, 2002 and 2001, respectively, and $32 million and $127 million of net realized losses were recognized in Other Income and Deductions in Exelon's Consolidated Income Statements for 2002 and 2001, respectively. The available-for-sale securities held at December 31, 2002 have an average maturity of six to seven years. The cost of these securities was determined on the basis of specific identification. See Note 11 - Nuclear

Decommissioning and Spent Fuel Storage for further information regarding the nuclear decommissioning trusts.

19. Commitments and Contingencies

Capital Commitments

Exelon and British Energy, Generation's joint venture partner in AmerGen, have each agreed to provide up to $100 million to AmerGen at any time that the Management Committee of AmerGen determines, that in order to protect the public health and safety and/or to comply with NRC requirements, such funds are necessary to meet ongoing operating expenses or to safely maintain any AmerGen plant. Although Exelon does not anticipate that AmerGen will make any acquisitions in 2003, Exelon has committed to provide AmerGen with capital contributions equivalent to 50% of the purchase price of any acquisitions AmerGen makes in 2003.

Generation has a 70% interest in the Southeast Chicago Energy Project, LLC (Southeast Chicago), which owns a peaking facility in Chicago. Southeast Chicago is obligated to make equity distributions of $54 million over the next 20 years to the party, which is not affiliated with Generation, that owns the remaining 30% interest. This amount reflects a return of that party's investment in Southeast Chicago. 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 30% interest in Southeast Chicago. Additionally, Generation may be required to purchase the 30% interest upon the occurrence of certain events, including Generation's failure to maintain an investment grade rating.

Nuclear Insurance

The Price-Anderson Act limits the liability of nuclear reactor owners for claims that could arise from a single incident. As of January 1, 2003, the current limit is $9.5 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 and the remaining $9.2 billion is provided through mandatory participation in a financial protection pool. Under the Price-Anderson Act, all nuclear reactor licensees can be assessed up to $89 million per reactor per incident, payable at no more than $10 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 expired on August 1, 2002 but existing facilities, including those owned and operated by Generation, remain covered. The U.S. Congress has extended the provisions of the Price-Anderson Act related to commercial facilities through 2003. The extension was passed as part of the Consolidated Appropriations Resolution, 2003, which will be presented to the President of the United States for his signature. The extension would affect facilities obtaining NRC operating licenses in 2003. Existing facilities are unaffected by the extension.

Exelon carries property damage, decontamination and premature decommissioning insurance for each station loss 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 Exelon is required by the NRC to maintain, to provide for decommissioning the facility. Exelon is unable to predict the timing of the availability of insurance proceeds to Exelon and the amount of such proceeds that would be available. Under the terms of the various insurance agreements, Exelon could be assessed up to $124 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 insureds, 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 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, through its subsidiaries, Exelon is a member of an industry mutual insurance company that 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.

Exelon's maximum share of any assessment is $46 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 described above.

In addition, Exelon 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. Exelon 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.

Exelon is self-insured to the extent that any losses may exceed the amount of insurance maintained. Such losses could have a material adverse effect on Exelon's financial condition and results of operations.

Energy Commitments

Exelon's wholesale operations include the physical delivery and marketing of power obtained through its generation capacity, and long, intermediate and short-term contracts. Exelon maintains a net positive supply of energy and capacity, through ownership of generation assets and power purchase and lease agreements, to protect it from the potential operational failure of one of its owned or contracted power generating units. Exelon has also contracted for access to additional generation through bilateral long-term power purchase agreements. These agreements are firm commitments related to power generation of specific generation plants and/or are dispatchable in nature. Exelon enters into power purchase agreements with the objective of obtaining low-cost energy supply sources to meet its physical delivery obligations to its customers. Exelon 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 Exelon with physical power supply to enable it to deliver energy to meet customer needs. Exelon primarily uses financial contracts in its wholesale marketing activities for hedging purposes. Exelon also uses financial contracts to manage the risk surrounding trading for profit activities.

Exelon 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. Exelon also enters into contractual obligations to deliver energy to wholesale market participants who primarily focus on the resale of energy products for delivery. Exelon provides delivery of its energy to these customers through access to its transmission assets or rights for firm transmission.

Generation has power purchase agreements (PPAs) with Midwest Generation, LLC (Midwest Generation) for the purchase of capacity from its coal-fired stations through 2004. Contracted capacity and capacity available through the exercise of an annual option are 1,696 MWs and 3,949 MWs in 2003 and 2004, respectively.

The agreements also provide for the option to purchase 1,084 MWs of oil and gas-fired capacity, and 857 MWs of peaking capacity, subject to reduction.

Generation has entered into PPAs with AmerGen, under which it will purchase all the energy from Unit No. 1 at Three Mile Island Nuclear Station after December 31, 2001 through December 31, 2014. Under a January 1, 2003 PPA, Generation will purchase from AmerGen all of the residual energy from the Clinton Nuclear Power Station (Clinton), through December 31, 2003. Currently, the residual output is approximately 31% of the total output of Clinton. In accordance with the terms of the AmerGen partnership agreement, the 2003 PPA will be extended through the end of the AmerGen partnership agreement in 2006.

Exelon has a long-term supply agreement through December 2022 with Distrigas of Massachusetts, LLC to guarantee physical gas supply to its New England generating units. Under the agreement, prices are indexed to New England gas markets. At December 31, 2002, Exelon had long-term commitments, relating to the purchase and sale of energy, capacity and transmission rights from unaffiliated utilities and others, including the Midwest Generation and AmerGen contracts, as expressed in the following tables:

	Net Capacity Purchases (1)	Power Only Sales	Power Only Purchases from AmerGen	Power Only Purchases from Non-Affiliates	Transmission Rights Purchases (2)
2003	$ 589	$ 2,606	$ 280	$ 1,722	$ 86
2004	639	1,181	292	768	93
2005	356	355	472	283	84
2006	328	92	472	239	3
2007	408	22	179	227	--
Thereafter	3,742	1	2,638	829	--
Total	$ 6,062	$ 4,257	$ 4,333	$ 4,068	$ 266

(1) On October 2, 2002, Generation notified Midwest Generation of its exercise of termination options under the existing Collins Generating Station (Collins) and Peaking Unit (Peaking) Purchase Power Agreements. Generation exercised its termination options on 1,727 MWs in 2003 and 2004. In 2003, Generation will take 1,778 MWs of option capacity under the Collins and Peaking Unit Agreements as well as 1,265 MWs of option capacity under the Coal Generation Purchase Power Agreement. Net capacity purchases in 2004 include 3,474 MWs of optional capacity from Midwest Generation. Net Capacity Purchases also include capacity sales to TXU under the purchase power agreement entered into in connection with the purchase of two generating plants in April 2002, which states that TXU will purchase the plant output from May through September from 2002 through 2006. During the periods covered by the power purchase agreement, TXU will make fixed capacity payments and will provide fuel to Exelon in return for exclusive rights to the energy and capacity of the generation plants. The combined capacity of the two plants is 2,334 MWs.

(2) Transmission Rights Purchases include estimated commitments in 2004 and 2005 for additional transmission rights that will be required to fulfill firm sales contracts.

Commercial Commitments

Exelon's commercial commitments as of December 31, 2002, representing commitments not recorded on the balance sheet but potentially triggered by future events, including obligations to make payment on behalf of other parties and financing arrangements to secure our obligations, are as follows:

		Expiration within			
	Total	2003	2004-2005	2006-2007	2008 and beyond
Credit Facility (a)	$ 1,500	$ 1,500	$ --	$ --	$ -
Letters of Credit (non-debt) (b)	111	106	5	--	--
Letters of Credit (Long-Term Debt) (c)	456	305	151	--	--
Insured Long-Term Debt (d)	254	--	--	--	254
Guarantees of Letters of Credit(e)	226	226	--	--	--
Performance Guarantees (f)	101	--	--	--	101
Surety Bonds (g)	521	329	57	4	131
Energy Marketing Contract Guarantees (h)	124	114	10	--	--
Nuclear Insurance Guarantees (i)	1,380	--	--	--	1,380
Lease Guarantees (j)	13	--	--	2	11
Preferred Securities (k)	128	--	--	--	128
Sithe New England Equity Guarantee (l)	38	38	--	--	--
Guarantees of Long-Term Debt (m)	41	2	--	--	39
Total	$ 4,893	$ 2,620	$ 223	$ 6	$ 2,044

(a) Credit Facility - Exelon, along with ComEd, PECO and Generation, maintain a $1.5 billion 364-day credit facility to support commercial paper issuances. At December 31, 2002, there were no borrowings against the credit facility. Additionally, at December 31, 2002, there was $948 million of commercial paper outstanding.

(b) 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.

(c) Letters of Credit (Long-Term Debt) - Direct-pay letters of credit issued in connection with variable-rate debt in order to provide liquidity in the event that it is not possible to remarket all of the debt as required following specific events, including changes in the basis of determining the interest rate on the debt.

(d) Insured Long-Term Debt - Borrowings that have been credit-enhanced through the purchase of insurance coverage equal to the amount of principal outstanding plus interest.

(e) Guarantees of letters of credit - Guarantees issued to provide support for letters of credit as required by third parties. These guarantees could be called upon only in the event of non-payment by a subsidiary.

(f) Performance Guarantees - Guarantees issued to ensure execution under specific contracts.

(g) Surety Bonds - Guarantees issued related to contract and commercial surety bonds, excluding bid bonds.

(h) Energy Marketing Contract Guarantees - Guarantees issued to ensure performance under energy commodity contracts.

(i) Nuclear Insurance Guarantees - Guarantees of nuclear insurance required under the Price-Anderson Act. $1.1 billion of this total exposure is exempt from the $4.5 billion PUHCA guarantee limit by SEC rule.

(j) Lease Guarantees - Guarantees issued to ensure payments on building leases.

(k) Preferred Securities - Guarantees issued to guarantee the preferred securities of the subsidiary trusts of PECO. See Note 16 - Preferred Securities of Subsidiaries for further information.

(l) Sithe New England Equity Guarantee- See Note 3 - Acquisitions and Dispositions for further information on the $38 million guarantee. After construction of the SBG facilities is complete, Exelon could be required to guarantee up to an additional $42 million in order to ensure that the SBG facilities have adequate funds available for potential outage and other operating costs and requirements.

(m) Guarantees of Long-Term Debt - Issued to guarantee payment of subsidiary debt.

Unconsolidated Equity Investments. Generation is a 49.9% owner of Sithe and accounts for the investment as an unconsolidated equity investment. The Sithe New England purchase did not affect the accounting for Sithe as an equity investment. Separate from the Sithe New England transaction, Generation is subject to a Put and Call Agreement (PCA) that gives Generation the right to purchase (Call) the remaining 50.1% of Sithe, and gives the other Sithe shareholders the right to sell (Put) their interest to Generation. If the Put option is exercised, Generation has the obligation to complete the purchase.

The PCA originally provided that the Put and Call options became exercisable as of December 18, 2002 and expired in December 2005. However, upon Apollo Energy, LLC's (Apollo) purchase of Vivendi's 34.2% ownership and Sithe management's 1% share, Apollo agreed to delay the effective date of its Put right until June 1, 2003 and, if certain conditions are met, until September 1, 2003. There are also certain events that could trigger Apollo's Put right becoming effective prior to June 1, 2003 including Exelon being downgraded below investment grade by Standard and Poor's Rating Group or Moody's Investors Service, Inc., a stock purchase agreement between Exelon and Apollo being executed and subsequently terminated, or the occurence of any event of default, other than a change of control, under certain Exelon or Apollo credit agreements. Depending on the triggering event, Apollo's put price of approximately $460 million, growing at a market rate of interest, needs to be funded within 18 or 30 days of the Put being exercised. There have been no changes to the Put and Call terms with respect to Marubeni's remaining 14.9% interest.

The delay in the effective date of Apollo's Put right allows Exelon to explore a further restructuring of our investment in Sithe. Exelon is continuing discussions with Apollo and Marubeni regarding restructuring alternatives that are designed in part to resolve Exelon's ownership limitations of Sithe's qualifying facilities. Exelon would hope to implement any additional restructuring of its Sithe investment in 2003. If Exelon is unsuccessful in restructuring the Sithe transaction, Exelon will proceed to implement measures to address the ownership of the qualified facilities as well as divest non-strategic assets, for which the financial outcome is uncertain.

If Generation exercises its option to acquire the remaining outstanding common stock in Sithe, or if all the other stockholders exercise their Put Rights, the purchase price for Apollo's 35.2% interest will be approximately $460 million, growing at a market rate of interest. The additional 14.9% interest will be valued at fair market value subject to a floor of $141 million and a ceiling of $290 million.

If Generation increases its ownership in Sithe to 50.1% or more, Sithe may become a consolidated subsidiary and our financial results may include Sithe's financial results from the date of purchase. At December 31, 2002, Sithe had total assets of $2.6 billion and total debt of $1.3 billion. This $1.3 billion includes $624 million of subsidiary debt incurred primarily to finance the construction of six new generating facilities, $461 million of subordinated debt, $103 million of line of credit borrowings, $43 million of the current portion of long-term debt and capital leases, $30 million of capital leases, and excludes $453 million of non-recourse project debt associated with Sithe's equity investments. For the year ended December 31, 2002, Sithe had revenues of $1.0 billion. As of December 31, 2002, Generation had a $449 million equity investment in Sithe.

Environmental Issues

Exelon's operations have in the past and may in the future require substantial capital 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 owns or leases a number of real estate parcels, including parcels on which its operations or the operations of others may have resulted in contamination by substances that are considered hazardous under environmental laws. Exelon has identified 71 sites where former manufactured gas plant (MGP) activities have or may have resulted in actual site contamination. Exelon is 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, 2002 and 2001, Exelon had accrued $156 million for environmental investigation and remediation costs, including $125 million and $127 million, respectively, for MGP investigation and remediation that currently can be reasonably estimated. Included in the environmental investigation and remediation cost obligation as of December 31, 2002 and 2001 is $97 million and $100 million, respectively, that has been recorded on a discount basis (reflecting discount rates of 5.0% and 5.5%, respectively). Such estimates, reflecting the effects of a 2.5% and 3.0% inflation rate before the effects of discounting were $138 million and $154 million at December 31, 2002 and 2001, respectively.

Exelon anticipates that payments related to the discounted environmental investigation and remediation costs, recorded on an undiscounted basis, of $76 million will be incurred for the five-year period through 2007. 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.

Leases

Minimum future operating lease payments, including lease payments for vehicles, real estate, computers, rail cars and office equipment, as of December 31, 2002 were:

2003	$ 77
2004	59
2005	58
2006	54
2007	49
Remaining years	598
Total minimum future lease payments	$ 895

Rental expense under operating leases totaled $85 million, $75 million and $41 million in 2002, 2001 and 2000, respectively.

Litigation

Securities Litigation. Between May 8 and June 14, 2002, several class action lawsuits were filed in the Federal District Court in Chicago asserting nearly identical securities law claims on behalf of purchasers of Exelon securities between April 24, 2001 and September 27, 2001 (Class Period). The complaints allege that Exelon violated Federal securities laws by issuing a series of materially false and misleading statements relating to its 2001 earnings expectations during the Class Period. The court consolidated the pending cases into one lawsuit and has appointed two lead plaintiffs as well as lead counsel.

On October 1, 2002, the plaintiffs filed a consolidated amended complaint. In addition to the original claims, this complaint contains allegations of new facts and contains several new theories of liability. Exelon believes the lawsuit is without merit and is vigorously contesting this matter.

FERC Municipal Request for Refund. Three of ComEd's wholesale municipal customers filed a complaint and request for refund with FERC, alleging that ComEd failed to properly adjust its rates, as provided for under the terms of the electric service contracts with the municipal customers and to track certain refunds made to ComEd's retail customers in the years 1992 through 1994. In the third quarter of 1998, FERC granted the complaint and directed that refunds be made, with interest. On April 30, 2001, FERC issued an order granting rehearing in which it determined that its 1998 order had been erroneous and that no refunds were due from ComEd to the municipal customers. In August 2001, each of the three wholesale municipal customers appealed the April 30, 2001 FERC order to the Federal circuit court, which consolidated the appeals for the purposes of briefing and decision. The Federal circuit court has stayed the proceedings pending settlement negotiations among the parties.

Retail Rate Law. In 1996, several developers of non-utility generating facilities filed litigation against various Illinois officials claiming that the enforcement against those facilities of an amendment to Illinois law removing the entitlement of those facilities to state-subsidized payments for electricity sold to ComEd after March 15, 1996 violated their rights under the Federal and state constitutions. The developers also filed suit against ComEd for a declaratory judgment that their rights under their contracts with ComEd were not affected by the amendment. On November 25, 2002, the court granted developers' motions for summary judgment. The judge also entered a permanent injunction enjoining ComEd from refusing to pay the retail rate on the grounds of the amendment, and Illinois from denying ComEd a tax credit on account of such purchases. ComEd and Illinois have each appealed the ruling. ComEd believes that it did not breach the contracts in question and that the damages claimed far exceed any loss that any project incurred by reason of its ineligibility for the subsidized rate. ComEd intends to prosecute its appeal and defend each case vigorously.

Cotter Corporation Litigation. During 1989 and 1991, actions were brought in Federal and state courts in Colorado against ComEd and its subsidiary, Cotter Corporation (Cotter), seeking unspecified damages and injunctive relief based on allegations that Cotter permitted radioactive and other hazardous material to be released from its mill into areas owned or occupied by the plaintiffs, resulting in property damage and potential adverse health effects. In 1994, a Federal jury returned nominal dollar verdicts against Cotter on eight plaintiffs' claims in the 1989 cases, which verdicts were upheld on appeal. The remaining claims in the 1989 actions were settled or dismissed. In 1998, a jury verdict was rendered against Cotter in favor of 14 of the plaintiffs in the 1991 cases, totaling approximately $6 million in compensatory and punitive damages, interest and medical monitoring. On appeal, the Tenth Circuit Court of Appeals reversed the jury verdict, and remanded the case for new trial. These plaintiffs' cases were consolidated with the remaining 26 plaintiffs' cases, which had not been tried. The consolidated trial was completed on June 28, 2001. The jury returned a verdict against Cotter and awarded $16 million in various damages. On November 20, 2001, the District Court entered an amended final judgment that included an award of both pre-judgment and post-judgment interests, costs, and medical monitoring expenses that total $43 million. In November 2000, another trial involving a separate sub-group of 13 plaintiffs, seeking $19 million in damages plus interest was completed in Federal District Court in Denver. The jury awarded nominal damages of $42,500 to 11 of 13 plaintiffs, but awarded no damages for any personal injury or health claims, other than requiring Cotter to perform periodic medical monitoring at minimal cost. Cotter appealed these judgments to the Tenth Circuit Court of Appeals. Cotter is vigorously contesting the award.

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 these actions, as well as any liability arising in connection with the West Lake Landfill discussed in the next paragraph. In connection with Exelon's 2001 corporate restructuring, the responsibility to indemnify Cotter for any liability related to these matters was transferred by ComEd to Generation.

The United States Environmental Protection Agency (EPA) has advised Cotter that it is potentially liable in connection with radiological contamination at a site known as the West Lake Landfill in Missouri. 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 remediation for the site range from $0 million to $87 million. Once a remedy is selected, it is expected that the PRPs will agree on an allocation of responsibility for the costs. Until an agreement is reached, Generation cannot predict its share of the costs.

Raytheon Arbitration. In March 2001, two subsidiaries of Sithe New England Holdings (now Exelon New England Holdings) brought an action in the New York Supreme Court against Raytheon Corporation (Raytheon) relating to its failure to honor its guaranty with respect to the performance of the Mystic and Fore River projects, as a result of the abandonment of the projects by the turnkey contractor. In a related proceeding, in May 2002, Raytheon submitted claims to the International Chamber of Commerce Court of Arbitration seeking equitable relief and damages for alleged owner caused performance delays in connection with the Fore River Power Plant Engineering, Procurement & Construction Agreement (EPC Agreement). The EPC Agreement, executed by a Raytheon subsidiary and guaranteed by Raytheon, governs the design, engineering, construction, start-up, testing and delivery of an 800-MW combined-cycle power plant in Weymouth, Massachusetts. Raytheon recently amended its claim and now seeks 141 days of schedule relief (which would reduce Raytheon's liquidated damage payment for late delivery by approximately $25.4 million) and additional damages of $15.6 million. Raytheon also has asserted a claim for loss of efficiency and productivity as a result of an alleged constructive acceleration, for which a claim has not yet been quantified. Generation believes the Raytheon assertions are without merit and is vigorously contesting these claims. Hearings by the International Chamber of Commerce Court of Arbitration with respect to liability were held in January and February 2003. A decision on liability is expected to be issued in May 2003 and, if necessary, additional hearings will be held on damages in May and June of 2003.

Real Estate Tax Appeals. Generation is involved in tax appeals regarding a number of its nuclear facilities, Limerick Generating Station (Montgomery County, PA), Peach Bottom Atomic Power Station (York County, PA), and Quad Cities Station (Rock Island County, IL). Generation is also involved in the tax appeal for Three Mile Island (Dauphin County, PA) through AmerGen. Generation does not believe the outcome of these matters will have a material adverse effect on Generation's results of operations or financial condition.

General. Exelon is involved in various other litigation matters. The ultimate outcome of such matters, as well as the matters discussed above, while uncertain, are not expected to have a material adverse effect on its respective financial condition or results of operations.

Credit Contingencies

Generation is a counterparty to Dynegy in various energy transactions. In early July 2002, the credit ratings of Dynegy were downgraded by two credit rating agencies to below investment grade. As of December 31, 2002, Generation had a net receivable from Dynegy of approximately $3 million, and consistent with the terms of the existing credit arrangement, has received collateral in support of this receivable. Generation also has credit risk associated with Dynegy through Generation's equity investment in Sithe. Sithe is a 60% owner of the Independence generating station, a 1,040-MW gas-fired qualified facility that has an energy-only long-term tolling agreement with Dynegy, with a related financial swap arrangement. As of December 31, 2002, Sithe had recognized an asset on its balance sheet related to the fair market value of the financial swap agreement with Dynegy that is marked-to-market under the terms of SFAS No. 133. If Dynegy is unable to fulfill the terms of this agreement, Sithe would be required to impair this financial swap asset. We estimate, as a 49.9% owner of Sithe, that the impairment would result in an after-tax reduction of our equity earnings of approximately $10 million.

In addition to the impairment of the financial swap asset, if Dynegy was unable to fulfill its obligations under the financial swap agreement and the tolling agreement, we would likely incur a further impairment associated with the Independence plant. Depending upon the timing of Dynegy's failure to fulfill its obligations and the outcome of any restructuring initiatives, Exelon could realize an after-tax charge of between $0 and $130 million. In the event of a sale of our investment in Sithe to a third party, proceeds from the sale could be negatively impacted by approximately $120 million, which would represent an after-tax loss of approximately $65 million.

Additionally, the future economic value of AmerGen's purchased power arrangement with Illinois Power, a subsidiary of Dynegy, could be impacted by events related to Dynegy's financial condition.

20. Segment Information

Exelon evaluates the performance of its business segments based on Net Income.

Energy Delivery consists of the retail electricity distribution and transmission businesses of ComEd in northern Illinois and PECO in southeastern Pennsylvania and the natural gas distribution business of PECO located in the Pennsylvania counties surrounding the City of Philadelphia. Generation consists of electric generating facilities, energy marketing operations and Exelon's interests in Sithe and AmerGen. Enterprises consists of competitive retail energy sales, energy and infrastructure services, communications and other investments weighted towards the communications, energy services and retail services industries. An analysis and reconciliation of Exelon's business segment information to the respective information in the consolidated financial statements are as follows:

	Energy Delivery	Generation	Enterprises	Corporate	Intersegment Eliminations	Consolidated
Total Revenues:						
2002	$ 10,457	$ 6,858	$ 2,033	$ 346	$ (4,739)	$ 14,955
2001	10,171	6,826	2,292	341	(4,712)	14,918
2000	4,511	3,274	1,395	--	(1,681)	7,499
Intersegment Revenues:						
2002	$ 76	$ 4,226	$ 97	$ 341	$ (4,740)	$ --
2001	94	4,102	179	337	(4,712)	--
2000	24	1,185	472	--	(1,681)	--
Depreciation and Amortization:						
2002	$ 978	$ 276	$ 55	$ 31	$ --	$ 1,340
2001	1,081	282	69	17	--	1,449
2000	297	123	35	3	--	458
Operating Expenses:						
2002	$ 7,597	$ 6,349	$ 2,047	$ 402	$ (4,739)	$ 11,656
2001	7,578	5,954	2,369	371	(4,716)	11,556
2000 (a)	3,009	2,833	1,473	324	(1,667)	5,972
Interest Expense:						
2002	$ 854	$ 75	$ 14	$ 74	$ (51)	$ 966
2001	973	115	37	133	(151)	1,107
2000	522	41	17	63	(29)	614
Income Taxes:						
2002	$ 765	$ 217	$ 69	$ (53)	$ --	$ 998
2001	703	327	(43)	(56)	--	931
2000	421	160	(52)	(190)	--	339
Net Income/(Loss):						
2002	$ 1,268	$ 400	$ (178)	$ (50)	$ --	$ 1,440
2001	1,022	524	(85)	(33)	--	1,428
2000 (a)	587	260	(94)	(167)	--	586
Capital Expenditures:						
2002	$ 1,041	$ 990	$ 44	$ 75	$ --	$ 2,150
2001	1,105	858	61	64	--	2,088
2000	367	288	70	27	--	752
Total Assets:						
2002	$ 26,550	$ 11,007	$ 1,297	$ (1,376)	$ --	$ 37,478
2001	26,365	8,145	1,743	(1,509)	--	34,744

(a) Includes non-recurring items of $276 million ($177 million after income taxes) for Merger-related expenses in 2000.

Equity in earnings of AmerGen and Sithe of $88 million, $90 million and $4 million for 2002, 2001 and 2000, respectively, are included in Generation's Net Income. Equity in earnings (losses) of communications joint ventures and other investments of $3 million, $(19) million and $(45) million for 2002, 2001 and 2000, respectively, are included in Enterprises' Net Income. Equity in earnings (losses) of affordable housing investments of $(11) million and $(9) million for 2002 and 2001, respectively, are included in Corporate's Net Income.

21. Related Party Transactions

Exelon's financial statements reflect related-party transactions with unconsolidated affiliates as reflected in the tables below.

	For the Years Ended December 31,		
	2002	2001	2000
Purchased Power from AmerGen (1)	$ 273	$ 57	$ 52
Interest Income from AmerGen (2)	2	--	--
Interest Income from Sithe (3)	--	2	--
Interest Expense to Sithe (4)	2	--	--
Services Provided to AmerGen (5)	70	80	32
Services Provided to Sithe (6)	1	--	--
Services Provided by Sithe (7)	13	--	--

	December 31, 2002	December 31, 2001
Net Receivable from AmerGen (1,2,3)	$ 39	$ 44
Net Payable to Sithe (4,5)	7	--
Note Payable to Sithe (7)	534	--

(1) Generation has entered into PPAs dated December 18, 2001 and November 22, 1999 with AmerGen. Under the 2001 PPA, Generation has agreed to purchase from AmerGen all the energy from Unit No. 1 at Three Mile Island Nuclear Station from January 1, 2002 through December 31, 2014. Under the 1999 PPA, Generation agreed to purchase from AmerGen all of the residual energy from Clinton Nuclear Power Station (Clinton) through December 31, 2002. Currently, the residual output is approximately 31% of the total output of Clinton. In accordance with the terms of the AmerGen partnership agreement, the 1999 PPA will be extended through the end of the AmerGen partnership agreement in 2006.

(2) In February 2002, Generation entered into an agreement to loan AmerGen up to $75 million at an interest rate equal to the 1-month London Interbank Offering Rate plus 2.25%. In July 2002, the limit of the loan agreement was increased to $100 million and the maturity date was extended to July 1, 2003. As of December 31 2002, the outstanding principal balance of the loan was $35 million.

(3) In August 2001, Exelon loaned Sithe, an equity method investee of Generation, $150 million. The note, which bore interest at the eurodollar rate, plus 2.25%, was repaid in December 2001 with the proceeds of bank borrowings. In connection with the bank borrowings, Exelon provided the lenders with a support letter confirming its investment in Sithe and Exelon's agreement to maintain a positive net worth of Sithe.

(4) Under the terms of the agreement to acquire Sithe New England dated November 1, 2002, Generation issued a $534 million note to be paid in full on June 18, 2003 to Sithe. The note bears interest at the rate equal to LIBOR plus 0.875%. Interest accrued on the note as of December 31, 2002 was $2 million.

(5) Under a service agreement dated March 1, 1999, Generation provides AmerGen with certain operation and support services to the nuclear facilities owned by AmerGen. This service agreement has an indefinite term and may be terminated by Generation or AmerGen with 90 days notice. Generation is compensated for these services in an amount agreed to in the work order, which is not less than the higher of its fully allocated cost for performing each service or the market price for such service.

(6) Under a service agreement dated December 18, 2000, Generation provides certain engineering and environmental services for fossil facilities owned by Sithe and for certain developmental projects. Generation is compensated for these services in an amount agreed to in the work order, but not less than the higher of fully allocated costs for performing such services or the market price.

(7) Under a service agreement dated December 18, 2000, Sithe provides Generation certain fuel and project development services. Sithe is compensated for these services in the amount agreed to in the work order, but not less than the higher of fully allocated costs for performing such services or the market price.

22. Quarterly Data (Unaudited)

The data shown below include all reclassifications, including those required upon the adoption of EITF 02-3, which Exelon considers necessary for a fair presentation of such amounts:

	Operating Revenues		Operating Income		Income Before the Cumulative Effect of Changes in Accounting Principles		Net Income	
	2002	2001	2002	2001	2002	2001	2002	2001
Quarter ended:								
March 31	$ 3,357	$ 3,823	$ 605	$ 889	$ 238	$ 387	$ 8	$ 399
June 30	3,519	3,616	813	792	485	315	485	315
September 30	4,370	4,185	1,000	912	551	376	551	376
December 31	3,709	3,293	882	769	397	338	397	338

	Average Shares Basic Outstanding (in millions) 2002	2001	Earnings per Basic Share Before the Cumulative Effect of Changes in Accounting Principles 2002	2001	Earnings per Basic Share Net Income 2002	2001
Quarter ended:						
March 31	321	320	$ 0.74	$ 1.21	$ 0.02	$ 1.25
June 30	322	321	1.50	0.98	1.50	0.98
September 30	323	321	1.71	1.17	1.71	1.17
December 31	323	321	1.23	1.05	1.23	1.05

	Average Shares Diluted Outstanding (in millions) 2002	2001	Earnings per Diluted Share Before the Cumulative Effect of Changes in Accounting Principles 2002	2001	Earnings per Diluted Share Net Income 2002	2001
Quarter ended:						
March 31	323	324	$ 0.73	$ 1.19	$ 0.02	$ 1.23
June 30	324	324	1.50	0.97	1.50	0.97
September 30	324	323	1.70	1.16	1.70	1.16
December 31	325	322	1.22	1.05	1.22	1.05

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

	2002				2001			
	Fourth Quarter	Third Quarter	Second Quarter	First Quarter	Fourth Quarter	Third Quarter	Second Quarter	First Quarter
High Price	$ 53.06	$ 52.83	$ 56.99	$ 53.88	$ 48.69	$ 67.65	$ 70.26	$ 69.75
Low Price	42.38	37.85	50.10	45.90	39.65	38.75	62.10	53.60
Close	52.77	47.50	52.30	52.97	47.88	44.60	64.12	65.60
Dividends	0.44	0.44	0.44	0.44	0.43	0.42	0.42	0.55 (a)

(a) The first quarter dividend in 2001 was a pro rata dividend. Unicom and PECO each paid their shareholders pro rata, per diem dividends from their last regular dividend dates through October 19, 2000. The first quarter covered the 119-day period from the date of the Merger, through the February 15, 2001 record date.

23. Subsequent Events

On January 22, 2003, ComEd issued $350 million of 3.70% First Mortgage Bonds, due on February 1, 2008 and $350 million of 5.875% First Mortgage Bonds, due on February 1, 2033. These bond proceeds were used to refinance long-term debt that had been retired during the third and fourth quarters of 2002. As part of these bond issuances, ComEd settled various forward starting interest rate swaps, for $43 million, which will be recorded as a regulatory asset and amortized over the life of the debt issuance.

On January 31, 2003, ComEd called $236 million of its First Mortgage Bonds at a redemption price of 103.86% of the principal amount, plus accrued interest to the March 18, 2003 redemption date. The bonds, which carried an interest rate of 8.375% and had a maturity date of February 15, 2023, are expected to be refinanced with long-term debt.

On February 14, 2003, ComEd called $200 million of its Trust Preferred securities at a redemption price of 100% of the principal amount, plus accrued interest to the March 20, 2003 redemption date. The preferred securities, which carried an interest rate of 8.48% and had a maturity date of September 30, 2035, are expected to be refinanced with trust preferred securities.

On February 20, 2003, ComEd entered into separate agreements with the City of Chicago (City) and with Midwest Generation (Midwest Agreement). Under the terms of the agreement with the City, ComEd will pay the City $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. Under the terms of the Midwest Agreement, ComEd will receive from Midwest Generation $36 million over ten years, $22 million of which was received on February 20, 2003, to relieve Midwest Generation's obligation under the fossil sale agreement. Midwest Generation will also assume from the City a Capacity Reservation Agreement which the City had entered into with Calumet Energy Team, LLC (CET), that is effective through June 2012. ComEd will reimburse the City for any nonperformance by Midwest Generation under the Capacity Reservation Agreement and will pay approximately $2 million for amounts owed to CET by the City at the time the agreement is executed. The net effect of the settlement to ComEd will be amortized over the remaining life of the franchise agreement with the City.