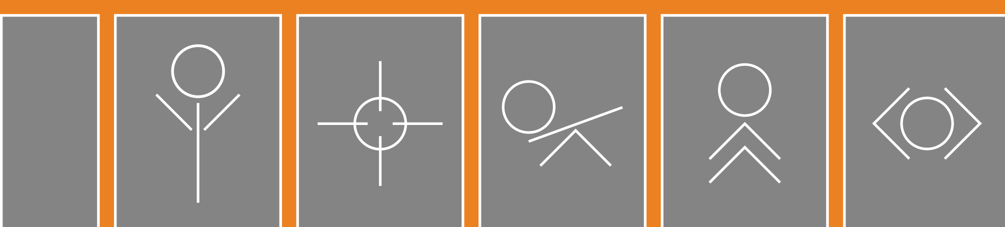


The Exelon Way

Exelon Corporation 03 Annual Report

Exelon Corporation is one of the nation's largest electric utilities with approximately 5.1 million electric customers in northern Illinois and southeastern Pennsylvania and approximately 460,000 gas customers in the Philadelphia area. The company has one of the industry's largest portfolios of electricity generation capacity, with a nationwide reach and strong positions in the Midwest and Mid-Atlantic. The Company also has holdings in such competitive businesses as energy and energy services. Exelon's market capitalization at the end of 2003 was $21.8 billion. Headquartered in Chicago, Exelon trades on the NYSE under the ticker EXC.

The Exelon Way: Our ongoing, company-wide effort to reexamine and ultimately transform the way we do business. Our goal is to continuously improve overall performance and productivity and reduce costs, while maintaining our primary focus on customer service, reliability and safety. Simply stated, The Exelon Way will help us to realize our Vision to build exceptional value by becoming the best and most consistently profitable electricity and gas company in the United States.

This past year, we have been engaged in an ongoing, across-the-board effort to energize our workforce; centralize key functions; optimize the work we do and the way we do it; emphasize our basic commitments to our customers, our employees and the communities we serve; and ultimately maximize our competitive position and shareholder value.

TO OUR SHAREHOLDERS

2003 marked my sixth year at Exelon, and my 20th year as a CEO in the electric utility industry. Much has changed since I was given the opportunity to lead Central Maine Power Company back in 1984. The industry has gone through profound regulatory and financial turmoil, beginning with PURPA (Public Utility Regulatory Policy Act) and integrated resource management, progressing through wholesale and retail competition, the California energy crisis, the Enron debacle, the telecom and merchant generation bubbles, the collapse of wholesale energy trading and, most recently the August 14, 2003 blackout. By any measure, these have been challenging times for our industry and its investors. I am proud to say that the companies that I have led have adapted to these changes, improved service and increased shareholder value.

Despite all this turmoil, even chaos, recent experience only confirms that this is a business about real service, with real assets and real customers. The old-fashioned virtues of reliability, safety, integrity, operating know-how and cost containment are even more important today than when I first joined Central Maine, or even back when the first Edison companies were created.

At Exelon, we have done well because we have adapted to the dramatic changes around us, and more fundamentally because we have never lost sight of the basics. Consistent with our corporate Vision Statement, which we first introduced in 2002 and discussed at length in these pages last year, we have challenged ourselves to live up to our reliability and safety commitments while relentlessly pursuing greater productivity, quality and innovation. We seek to build exceptional value by becoming the best and most consistently profitable electricity and gas company in the United States. We do not claim to have achieved this goal; we will not waiver in this effort.

SUCCEEDING IN CHALLENGING TIMES

2003 has been a year of significant operating accomplishments, and painful investment write-offs. I am delighted to report that 2003 adjusted (non-GAAP) operating earnings were $5.22 per share, eight percent above 2002 adjusted (non-GAAP) operating earnings.* As a result, on January 27, 2004, the Exelon Board of Directors approved a further 10 percent increase in the quarterly dividend rate, from 50 cents per share to 55 cents per share.

All told, we have increased our dividend rate by 20 percent over the past 12 months, and by 30 percent since Exelon was created. The Board also approved a 2-for-1 stock split contingent upon required regulatory approvals and the filing of an amendment to our articles of incorporation. Both the increased dividend level and the proposed stock split should make our shares more attractive to retail investors.

* For a reconciliation of adjusted (non-GAAP) operating earnings to GAAP (accounting principles generally accepted in the United States) earnings, see Exelon's fourth quarter earnings release, issued January 28, 2004, posted on the Investor Relations page at www.exeloncorp.com and included in the 8-K filed with the SEC on that date.

Full year 2003 earnings prepared in accordance with GAAP were $905 million, or $2.75 per diluted share. Our consolidated GAAP earnings reflect several unusual events, including a $573 million, or $1.74 per share, after-tax charge for the impairment of the Boston Generating assets; a $180 million, or $0.55 per share, after-tax charge related to Exelon's investment in Sithe; and a $159 million, or $0.49 per share, after-tax severance and severance-related charge associated with The Exelon Way.

While we are most disappointed by the write-offs, and accept responsibility for investments that have not succeeded, the market is judging us on our overall performance in the context of the industry as a whole. All of our competitors faced the same challenges that we faced, and many of these companies are now half the size they were in 2000, or gone completely. From the date of the Unicom/PECO merger in October of 2000 through the end of 2003, Exelon's stock price was up more than 11 percent. Both the Philadelphia Utility Index (UTY) and the S&P Electrics were down more than 15 percent, and the S&P 500 was down more than 20 percent. Exelon outperformed the UTY by more than 25 percent and the S&P 500 by more than 30 percent.

As a consequence, Exelon's overall market capitalization has continued to rise over the past six years. When Oliver Kingsley and I first came to Unicom, the combined market cap of Unicom and PECO was approximately $12.1 billion. At the end of 2003, the market cap of Exelon was $21.8 billion, an 80 percent increase or $9.7 billion of value creation. Today, Exelon enjoys one of the two largest market capitalizations in the industry. We have also reduced our debt-to-capital ratio and increased our cash flow. We are a financially strong company with the resources and the will to confront future challenges.

Our success is the culmination of the work of many people.

- Exelon Generation has completed its first full year as an integrated organization with Ian McLean and John Young in key leadership roles. Annual net generation increased to 142,000 gigawatt-hours, and revenues net of purchased power and fuel expense increased $410 million from 2002 to 2003.
- Jack Skolds, Chris Crane and their team worked to bring all-in nuclear costs to an all time low, 1.97 cents per kilowatt-hour, consistent with first quartile industry performance.
- Exelon Energy Delivery, under Frank Clark and Denis O'Brien, made substantial progress in reducing layers of management and consolidating operations.
- Barry Mitchell and his treasury team made further progress reducing our cost of debt. Since 2000, we have retired $1.9 billion in transition debt and retired or refinanced $5.0 billion of other debt, thereby reducing annualized interest expense by about $219 million.
- In our Business Services Company, Ruth Ann Gillis and her IT and Supply Chain teams have completed multiple initiatives to increase efficiency and reduce costs.

THE EXELON WAY

In January of 2003, we initiated The Exelon Way, an aggressive and comprehensive company-wide effort to reexamine and ultimately transform the way we do business. This past year, we have been engaged in this ongoing, across-the-board effort to *energize* our workforce; *centralize* key functions; *optimize* the work we do and the way we do it; *emphasize* our basic commitments to our customers, our employees and the communities we serve; and ultimately *maximize* our competitive position and shareholder value. We are creating a unified, high-performance organization, building on a culture of excellence that will enable us to realize more than $1 billion in cash flow enhancements over the next three years.

To lead this effort, and oversee all of our operations, in April the Board accepted my recommendation to promote Oliver Kingsley to a newly created position as president and chief operating officer. We are already seeing tangible results from the work that Oliver and The Exelon Way team have undertaken. Gary Snodgrass and his HR team worked tirelessly to optimize our workforce and assure that we have the right people in the right places. By the end of the third quarter, we had completed initial benchmarking, begun restructuring and centralization, and were well on the way to real savings across our entire business. By year-end, we actually realized $170 million in savings over program baseline in reduced operations and maintenance, and capital expenditures – savings that weren't anticipated until 2004.

In short, The Exelon Way is about being the best at everything we do. Our goal is to continuously improve overall productivity and reduce costs, while maintaining our primary focus on customer service, reliability and safety.

LEADING THE WAY FORWARD

The Exelon Way is not an end unto itself. Our Vision Statement speaks to more than operational prowess. It urges us to confront the future, to adapt to rapid changes in markets, politics, economics and technology, and to promote and implement policies that build effective markets.

Living up to this ambition is an enormous challenge, given the legislative and regulatory uncertainty that the industry now faces. We operate today in a strange mixture of competition and regulation that leaves unanswered where markets begin and end, and where regulatory policy transcends markets. Resolving this dilemma may ultimately prove more challenging than achieving top quartile operating performance.

Exelon remains committed to deep, liquid, competitive wholesale markets. Under the leadership of Betsy Moler, our Executive Vice President of Government Affairs, Exelon has worked tirelessly to promote wholesale competition both before Congress and the Federal Energy Regulatory Commission (FERC). Among our more challenging undertakings has been a vigorous effort to bring ComEd within PJM. PJM is clearly the nation's preeminent regional transmission organization, the leader in wholesale market development. Through the efforts of our PJM team, the PJM Board voted to admit ComEd effective March 1, 2004. We are presently seeking FERC approval, over the strenuous objection of a host of competing interests.

Exelon also believes that our energy delivery companies, ComEd and PECO, must be ready, willing and able to meet the needs of all of our customers, whether they require only delivery service, or whether, like most small customers, they require delivery service and a great deal more. In reality, our residential customers demand a sophisticated "basic service" product, one uniquely suited to the traditional utility. These customers are not an afterthought; they form the very core of our business, and our commitments.

We are engaged in a vigorous public debate in both Illinois and Pennsylvania about how best to meet the needs of these customers. We are actively pursuing a variety of solutions that work for both customers and shareholders. The outcome must ensure the right of individual customers to choose competitive suppliers, while preserving the right of other customers to choose to remain with their traditional utility provider. Success, as always, depends upon aligning the interests of customers and investors.

The utility of the future will also face ever-increasing environmental challenges. Lately, I have been working with the National Commission on Energy Policy in an effort to strike a realistic balance between environmental and energy policy. The day may soon come when policy makers will conclude that climate change is a real threat, and it is imperative that we act now to ensure that lower carbon alternative fuels, including natural gas, nuclear, and sustainable renewables, are available to meet the future energy needs of our economy.

THE VISION REMAINS, BUT THE GOALS EVOLVE

In 2003, we amended one of the three Strategic Goals included in our original Vision Statement. Rather than *Invest in Our Consolidating Industry*, the third Strategic Goal is now *Build Value Through Disciplined Financial Management*. The overall Vision remains the same – we just intend to get there in a more deliberate fashion.

Throughout 2003, we have shown that discipline. We have continued our orderly sale and transition out of various Exelon Enterprises ventures, including the recent sale of InfraSource, the result of a long effort by George Gilmore and Pam Strobel. In July, we announced our intention to transition out of the ownership of the Boston Generating facilities. Our internal financial analysis clearly showed that we would be obliged to make significant equity infusions to preserve the projects with little prospect for adequate return. Randy Mehrberg and Bob Shapard have led the effort to disengage from these investments.

In contrast, in early October we announced our decision to acquire British Energy's 50 percent interest in AmerGen Energy Company, LLC, thereby giving us sole ownership of AmerGen and its three nuclear units. Unlike the situation in New England, the AmerGen acquisition involved plants with operating histories well known to us, plants located in and around our retail service territories. I am pleased to report that the AmerGen acquisition has proven immediately accretive to earnings.

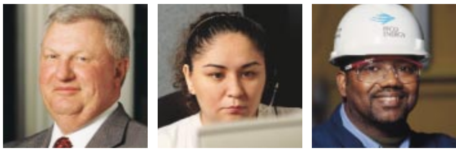
Late in the year, we also attempted to acquire Illinois Power. Although IP was an attractive merger partner because of its proximity and the opportunity for synergies, the proposed transaction was expressly conditioned upon provisions that would ensure sufficient revenue. When those conditions were not met, we decided not to proceed with the transaction. It was a painful decision, but one that I am confident was right.

At Exelon, we continue to concentrate on what we do well, which when you think about it, is quite a lot. Every day, we strive to perfect the fundamentals of running a truly national utility business–one that extends across many states and includes the operation of 17 nuclear reactors at 10 stations, 5.1 million retail electric customer accounts serving a population of 12 million, 460,000 gas customer accounts serving a population of 2 million, 6,700 circuit miles of transmission, 96,200 circuit miles of electric distribution, and 11,600 gas pipeline miles. We are determined to be a first quartile performance leader in every aspect of this business, and through The Exelon Way, we are making steady progress.

In the end, we will remain Exelon, one company, one vision, striving to deliver extraordinary service to our customers and extraordinary value to our shareholders. Our customers, and you our shareholders, deserve no less.

John W. Rowe
Chairman and Chief Executive Officer
March 1, 2004

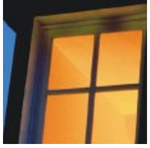
Energize: Through The Exelon Way, we are redefining performance expectations at all levels, and reinforcing those expectations through leadership by example. We strive to create a high-performance, diverse culture where all of our employees focus on results and embrace continuous improvement in their daily work lives. We are energizing our employees by asking them to be the best at everything they do. Exelon people have the talent, and we are calling upon that talent, and their commitment, so that we may *relentlessly pursue top quartile performance levels in productivity, quality, safety and customer satisfaction*.



Centralize: Through The Exelon Way, we are centralizing our organization to become one company, with one vision. We have adopted a single model for all of our business units, a single source for each of our support functions, and a single approach to our operating procedures. In areas such as Information Technology and Supply, which provide services to each of Exelon's business units, we have integrated staff and operating procedures for more effective service results. By centralizing and aligning our organization, we can *perform at world-class levels as we seek effective integration across businesses and optimization of the whole*.

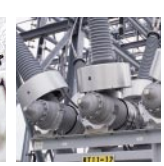
Optimize: Through The Exelon Way, we are optimizing the work we do, and the way we do it. We strive to work better and smarter–not just harder. We employ rigorous benchmarking to standardize the work, and more effectively deploy the people who do it. Having the right people with the right skills in the right places, and providing them with the training and resources they require, is critical to our success. By optimizing our work and workforce, we realize the benefits of a *common business model, common operating procedures, and best practices across our company*.





Emphasize: Through The Exelon Way, we are emphasizing our commitment to reliability, safety and the environment. Providing reliable service is central to who we are and what we do. Ensuring the safety of our customers and employees is equally fundamental. Preserving the environment requires that we do more than merely comply with rules and regulations; we must seek continuous improvement here as well. By emphasizing these core values, *we live up to our commitments to keep the lights on, perform safely, and constantly improve our environmental performance*.

Maximize: Through The Exelon Way, we are maximizing not only our earnings and cash flow, but also our competitive future. Our goal is to deliver $300 million in additional annual cash flow by 2004, and $600 million annually by 2006. We are well on the way to achieving that goal. By year-end 2003, we already realized $170 million in savings from The Exelon Way—savings not originally anticipated until 2004. By maximizing our earnings and cash flow, *we build value through disciplined financial management*.



EXELON ENERGY DELIVERY

Exelon Energy Delivery (EED) has the largest electric customer base in the nation, serving approximately 5.1 million retail electric customer accounts and approximately 460,000 natural gas customer accounts. With approximately 8,200 employees, EED distributes approximately 123,000 gigawatt-hours of electricity annually to customers via 102,900 circuit miles of overhead lines and underground cables. PECO Energy also provides approximately 88,000 million cubic feet of natural gas annually through 11,600 gas pipeline miles.

Operationally, 2003 was a challenging year as hundreds of crews in both markets went head-to-head against Mother Nature's fury. It also was a year marked by leadership changes designed to streamline the organization, gain efficiencies and improve performance across ComEd and PECO.

Throughout EED, The Exelon Way is already helping deliver results and positive change for the future through a number of initiatives. EED consolidated the ComEd and PECO organizations in the following areas: Customer and Marketing Services, Distribution Operations, Transmission Operations, Asset Management, and Support Services. In order to foster cost-effective reliability, EED's Asset Management division redesigned the capital and operating and maintenance investment process. The new process standardizes criteria for infrastructure investments across both EED gas and electric systems. The consolidation of East and West operations enabled more than 200 ComEd storm restoration personnel to assist in restoration of service for PECO customers following Hurricane Isabel. This reduced the cost of the restoration effort by reducing the dependency on and expense of third party resources.

EXELON GENERATION

Exelon Nuclear, with a workforce of approximately 6,600, operates the largest nuclear fleet in the United States and the third largest commercial nuclear fleet in the world. Through its focus on safe operations and reliable production, Exelon Nuclear is a leader in the nuclear power industry. In 2003, Exelon Nuclear produced more power during the vital summer period than any summer since the company was formed, and was awarded three of 14 Top Industry Practice awards presented by the Nuclear Energy Institute. Peach Bottom Atomic Power Station was granted a 20-year extension of its operating license, a first for Exelon. Three Mile Island Unit 1 set a world record for continuous days of operation for its reactor type (680 days) and Braidwood Unit 2 set a U.S. outage duration record for its reactor type of less than 16 days.

Exelon Power manages, operates and maintains the company's fossil (coal, oil and natural gas), landfill gas and hydroelectric fleet of generating assets. Exelon Power's generating units provide baseload, intermediate and peak generation when Exelon's Power Team calls, providing the safe, reliable, and environmentally conscious production of power. As part of The Exelon Way, Exelon Power has made great strides in further optimizing the performance of its units and its maintenance programs, improving unit availability ratings throughout 2003.

Exelon Power Team is the wholesale power marketing division of Exelon Generation. Power Team focuses on optimizing the value of Exelon's generating portfolio while providing bulk physical power to Exelon's ComEd and PECO Energy operating companies in the Chicago and Philadelphia metropolitan areas. For its part of The Exelon Way, Power Team realized significant cost savings by exercising Exelon's rights to release expensive supply contracts and taking advantage of lower-priced market alternatives. During late 2003, Power Team reorganized to increase its focus on asset value optimization. As part of the changes, Exelon Generation created a separate Business Development & Marketing division to manage longer-term commercial strategy, planning and business development activities.

EXELON ENTERPRISES

As promised, Exelon proceeded with focusing on its core utility business in 2003. In doing so, Exelon has moved forward in divesting its non-strategic businesses in the Enterprises unit. In 2003, Exelon sold the majority of InfraSource; signed sale agreements for Exelon Thermal, which are expected to close in 2004; and will transfer the Exelon Energy business to the Generation segment in 2004. Now with approximately 2,200 employees, Enterprises is currently comprised of the energy and mechanical services business of Exelon Services, Inc., the remaining infrastructure services business, a communications joint venture and other investments.

Throughout 2004, we will strive to continue to improve operations and profitability while positioning non-strategic businesses for possible divestiture.

BUSINESS SERVICES COMPANY

Exelon's Business Services Company (BSC) is a direct, wholly owned subsidiary of Exelon Corporation. With approximately 1,900 employees, BSC provides Exelon's businesses with information technology, supply management, legal, finance, human resources, and audio/visual services.

As a central service provider, BSC delivers value to Exelon's business units and optimizes solutions for the company as a whole. In line with The Exelon Way, BSC has become more efficient across the board, made process improvements, achieved cost savings, and established an organization that readies Exelon for the long term.

During 2003, Exelon's supply and IT functions were centralized within BSC. Through the ongoing supply chain reorganization, Exelon has improved processes and leveraged its purchasing power, leading to significant cost reductions. By centralizing the IT function, Exelon has standardized information technology across Exelon, identifying ways to increase overall effectiveness, implement standard processes, and achieve cost savings.

In 2004, BSC will continue to provide exceptional value and service, supporting the needs of Exelon's business units.

pictured left to right

John F. Young
Senior Vice President

John W. Rowe
Chairman and Chief Executive Officer

Oliver D. Kingsley, Jr.
President and Chief Operating Officer

David W. Woods
Senior Vice President

Pamela B. Strobel
Executive Vice President and Chief Administrative Officer

S. Gary Snodgrass
Senior Vice President and Chief Human Resources Officer

Ruth Ann M. Gillis
Senior Vice President

Robert S. Shapard
Executive Vice President and Chief Financial Officer

Ian P. McLean
Executive Vice President

Elizabeth A. Moler
Executive Vice President

Michael A Bemis
Senior Vice President

Randall E. Mehrberg
Executive Vice President and General Counsel

Frank M. Clark
Senior Vice President

J. Barry Mitchell
Senior Vice President

John L. Skolds
Senior Vice President

Katherine K. Combs
Vice President, Corporate Secretary and Deputy General Counsel

George H. Gilmore Jr.
Senior Vice President

Richard H. Glanton
Senior Vice President

Denis P. O'Brien
President, PECO Energy Company

pictured left to right

Ronald Rubin
Chairman and Chief Executive Officer, Pennsylvania Real Estate Investment Trust

Edgar D. Jannotta
Chairman, William Blair & Company, LLC

John W. Rowe
Chairman and Chief Executive Officer, Exelon Corporation

Nicholas DeBenedictis
Chairman and Chief Executive Officer, Philadelphia Suburban Corporation

Bruce DeMars
Admiral (Retired), United States Navy

G. Fred DiBona, Jr.
President and Chief Executive Officer, Independence Blue Cross

Sue L. Gin
Chairman and Chief Executive Officer, Flying Food Group, LLC

Richard L. Thomas
Retired Chairman, First Chicago NBD Corporation

Edward A. Brennan
Executive Chairman of AMR and American Airlines
Retired Chairman and Chief Executive Officer, Sears, Roebuck and Co.

M. Walter D'Alessio
Vice Chairman, NorthMarq Capital, Inc.

Rosemarie B. Greco
Director, Office of Health Care Reform, Commonwealth of Pennsylvania

John W. Rogers, Jr.
Chairman and Chief Executive Officer, Ariel Capital Management, LLC

John M. Palms, Ph.D.
Distinguished President Emeritus, University of South Carolina

Financial Section

in millions, except for per share data	2003	2002	2001(a)	2000(b)	1999
					For the Years Ended December 31,
Statement of Income data:					
Operating revenues	**$15,812**	$14,955	$14,918	$7,499	$5,478
Operating income	**2,198**	3,299	3,362	1,527	1,373
Income before cumulative effect of changes in accounting principles	**$ 793**	$ 1,670	$ 1,416	$ 562	$ 570
Cumulative effect of changes in accounting principles (net of income taxes)	**112**	(230)	12	24	–
Net income	**$ 905**	$ 1,440	$ 1,428	$ 586	$ 570
Earnings per average common share (diluted):					
Income before cumulative effect of changes in accounting principles	**$ 2.41**	$ 5.15	$ 4.39	$ 2.75	$ 2.89
Cumulative effect of changes in accounting principles (net of income taxes)	**0.34**	(0.71)	0.04	0.12	–
Net income	**$ 2.75**	$ 4.44	$ 4.43	$ 2.87	$ 2.89
Dividends per common share	**$ 1.92**	$ 1.76	$ 1.82	$ 0.91	$ 1.00
Average shares of common stock outstanding—diluted	**329**	325	322	204	197

in millions	2003	2002	2001(a)	2000(b)	1999
					December 31,
Balance Sheet data:					
Current assets	**$ 4,580**	$ 4,125	$ 3,735	$ 4,151	$ 1,221
Property, plant and equipment, net	**20,630**	17,957	14,665	13,758	4,982
Regulatory assets	**5,226**	5,546	5,774	6,313	6,094
Goodwill	**4,719**	4,992	5,335	5,186	121
Other deferred debits and other assets	**6,786**	5,249	5,460	5,378	669
Total assets	**$ 41,941**	$37,869	$34,969	$34,786	$13,087
Current liabilities	**$ 5,688**	$ 5,874	$ 4,370	$ 4,993	$ 1,286
Long-term debt, including long-term debt to financing trusts(c)	**13,489**	13,127	12,879	12,958	5,969
Regulatory liabilities	**1,891**	486	225	–	–
Other deferred credits and other liabilities	**12,283**	9,968	8,749	8,959	3,726
Minority interest	**–**	77	31	31	12
Preferred securities of subsidiaries(c)	**87**	595	613	630	321
Shareholders' equity	**8,503**	7,742	8,102	7,215	1,773
Total liabilities and shareholders' equity	**$ 41,941**	$37,869	$34,969	$34,786	$13,087

(a) Effective January 1, 2001, Exelon Corporation separated its generation and other competitive businesses from its regulated energy delivery business at Commonwealth Edison Company and PECO Energy Company.

(b) Reflects the effects of the merger of Exelon Corporation, Unicom Corporation and PECO Energy Company on October 20, 2000 (Merger). The Merger was accounted for using the purchase method of accounting with PECO Energy Company as the acquiring company. Accordingly, financial results for 2000 consist of PECO Energy Company's results for 2000 and Unicom Corporation's results after October 20, 2000.

(c) Upon adoption of Financial Accounting Standards Board (FASB) Interpretation (FIN) No. 46 (revised December 2003), "Consolidation of Variable Interest Entities" (FIN No. 46-R) in 2003, the mandatorily redeemable preferred securities of ComEd and PECO were reclassified as long-term debt to financing trusts as of December 31, 2003.

(Dollars in millions, unless otherwise noted)

GENERAL BUSINESS

Exelon Corporation (Exelon) is a registered public utility holding company that, through its subsidiaries, operates in three business segments—Energy Delivery, Generation and Enterprises—as described below. See Note 21 of the Notes to Consolidated Financial Statements for further segment information. In addition to our three business segments, Exelon Business Services Company (BSC) provides Exelon and its subsidiaries with financial, human resource, legal, information technology, supply management and corporate governance services.

Energy Delivery

Our energy delivery business consists of the regulated sale of electricity and distribution and transmission services by Commonwealth Edison Company (ComEd) in northern Illinois and by PECO Energy Company (PECO) in southeastern Pennsylvania and the regulated sale of natural gas and distribution services by PECO in the Pennsylvania counties surrounding the City of Philadelphia.

ComEd. 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 regulated by the Illinois Commerce Commission (ICC) as to rates, the issuance of securities and certain other aspects of ComEd's operations. ComEd is also subject to regulation by the Federal Energy Regulatory Commission (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. The service territory includes the City of Chicago (Chicago), an area of about 225 square miles with an estimated population of three million. ComEd has approximately 3.6 million customers.

PECO. PECO is engaged principally in the purchase, transmission, distribution and sale of electricity and in the purchase, distribution and sale of natural gas to residential, commercial and industrial customers. PECO is regulated by the Pennsylvania Public Utility Commission (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 the 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 3.9 million, including 1.5 million in the City of Philadelphia. Natural gas service is supplied in an approximate 1,900 square mile area in southeastern Pennsylvania adjacent to Philadelphia, with a population of approximately 2.4 million. PECO delivers electricity to approximately 1.5 million customers and natural gas to approximately 460,000 customers.

Generation

Our generation business consists of the owned and contracted for electric generating facilities and energy marketing operations of Exelon Generation Company, LLC (Generation) and a 50% interest in Sithe Energies Inc. (Sithe) and, effective January 1, 2004, the competitive retail sales business of Exelon Energy Company.

Generation is one of the largest competitive electric generation companies in the United States, as measured by owned and controlled megawatts (MWs). Generation combines its large generation fleet with an experienced wholesale power marketing operation. Generation owns generation assets in the Northeast, Mid-Atlantic, Midwest and Texas regions with a net capacity of 28,492 MWs, including 16,959 MWs of nuclear capacity, and controls another 12,703 MWs of capacity in the Midwest, Southeast and South Central regions through long-term contracts. Generation's ownership interests include 3,145 MWs of capacity owned by Boston Generating, LLC (Boston Generating), a project subsidiary of Exelon New England, formerly known as Exelon Boston Generating, LLC. In July 2003, Generation commenced the process of an orderly transition out of the ownership of Boston Generating. This transition is anticipated to occur in 2004.

In addition to its owned generating facilities, Generation owns a 50% interest in Sithe with another entity, with put and call options that could result in either party owning all of Sithe outright. While Exelon's intent is to fully divest Sithe, the timing of the put and call options vary by acquirer and can extend through March 2006. The pricing of the put and call options is dependent on numerous factors, such as the acquirer, date of acquisition and assets owned by Sithe at the time of exercise (see further discussion of Sithe in Contractual Obligations and Off-Balance Sheet Arrangements section below and in Note 3 of the Notes to Consolidated Financial Statements). Sithe develops, owns and operates 12 generation stations consisting of 15 units in North America. Currently, Sithe has a total generating capacity of 1,097 MWs in operation and 228 MWs under construction.

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 energy, or "load," requirements of ComEd and PECO.

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

Enterprises

Our enterprise business consists primarily of the energy services business of Exelon Services, Inc. (Exelon Services), the district cooling business of Exelon Thermal Holdings, Inc. (Thermal), the electrical contracting business of F&M Holdings, Inc., a communications joint venture and other investments weighted towards the communications, energy services and retail services industries. Effective January 1, 2004, Enterprises' competitive retail sales business, Exelon Energy Company, became part of Generation. We continue to pursue opportunities to sell other Enterprises businesses.

EXECUTIVE SUMMARY

2003 has been a year of operating accomplishments and painful investment write-offs. We have focused on living up to our reliability and safety commitments while pursuing greater productivity, quality and innovation.

Financial Results. We experienced an overall decline in diluted earnings per average common share of 38% in 2003. This decline was primarily due to a charge of $573 million (after-tax) related to the impairment of the long-lived assets of Boston Generating. In addition, we incurred impairment and transaction-related charges of $180 million (after-tax) related to our investment in Sithe and severance and severance-related charges approximating $159 million (after-tax) associated with The Exelon Way. Our energy delivery business experienced a decline in kilowatthour deliveries due to moderate weather, and the operating margins at our Enterprises business were lower due to the sale of the majority of the InfraSource Inc. business in the third quarter of 2003. Our 2003 results were favorably affected by modest improvements in wholesale energy prices, which increased Generation's energy margins, and by lower interest expense and a lower effective income tax rate. We also recorded an after-tax gain of $112 million upon the adoption of a new accounting standard that has a significant impact on how we account for our nuclear decommissioning obligation.

The Exelon Way. We implemented The Exelon Way, an aggressive plan defining how we will conduct business in years to come. The Exelon Way is focused on improving operating cash flows while meeting service and financial commitments through improved integration of operations and consolidation of support functions. Our targeted annual cash savings range from approximately $300 million in 2004 to approximately $600 million in 2006. In addition to the severance and severance-related charges we recorded during 2003, we anticipate incurring additional charges associated with The Exelon Way in future periods.

Investment Strategy. We continued to follow a disciplined approach to investing to maximize the earnings and cash flows from our assets and businesses and to sell those that do not meet our goals. Our 2003 highlights include:

– We announced our transition out of our ownership of Boston Generating in July 2003 because our internal financial analysis clearly showed that we would be obliged to make significant equity infusions to preserve the projects with little prospect of adequate return.
– We completed a series of transactions in November 2003 that restructured the ownership of Sithe, with Generation continuing to own a 50% interest in Sithe. We continue to pursue the divestiture of our investment in Sithe.
– We purchased British Energy plc's 50% interest in AmerGen Energy Company, LLC (AmerGen) in December 2003. AmerGen, which owns the Clinton Power Station, Three Mile Island Nuclear Station Unit 1 and the Oyster Creek Generating Station representing about 2,500 megawatts of capacity, is now our wholly owned subsidiary.
– We attempted to purchase Illinois Power Company and to resolve certain rate issues following the end of the current rate freeze at ComEd in 2006. Since the latter could not be accomplished at this time, the proposed Illinois Power transaction was abandoned.
– We continued to execute our divestiture strategy for Enterprises by selling the electric construction and services, underground and telecom businesses of InfraSource in September 2003 and entering into agreements in December 2003 to sell the Chicago operations and the Aladdin thermal facility of Thermal and certain direct investments held by Enterprises.

Financing Activities. We refinanced $2.4 billion of outstanding debt and equity securities in 2003 and repaid approximately $580 million of transitional trust notes and $260 million of long-term debt, resulting in expected annual interest savings of $96 million. We met all of our capital resource commitments with internally generated cash and expect to do so in the foreseeable future, absent new acquisitions. We increased our dividend rate by 20% over the past twelve months.

Operational Achievements. Our energy delivery and generation businesses focused on the core fundamentals of providing reliable delivery service and efficient generation to our customers. Energy Delivery, Generation's nuclear business and BSC combined resources to minimize the aftermath of Hurricane Isabel that affected the Philadelphia area and helped to prevent the potentially detrimental cascading effects of the August 14, 2003 blackout in the Northeastern United States and Canada (August Blackout) to our system and to our customers. Following several years of continued reliability improvement, Energy Delivery's performance dipped slightly in 2003 due to Hurricane Isabel and also due to a series of severe storms across Northern Illinois—two of which were the worst since 1998. Generation's nuclear fleet achieved a 93.4% capacity factor in 2003 compared to 92.7% in 2002 while reducing the costs of nuclear generation to 1.25 cents per kilowatthour.

Outlook for 2004 and Beyond. In the short term, our financial results will be affected by a number of factors, including weather conditions, wholesale market prices, successful implementation of The Exelon Way and our ability to generate electricity at low costs. If weather is warmer than normal in the summer months or colder than normal in the winter months, operating revenues at Energy Delivery generally will be favorably affected. Operating revenues will also be favorably affected by increases in wholesale market prices. In addition, we are required annually to assess the goodwill recorded at ComEd to determine if it is impaired. Based on certain anticipated reductions to cash flows subsequent to the restructuring transition period (primarily competitive transition charges that, under the current restructuring statute, will not be collected after 2006), we believe there is a reasonable possibility that goodwill will be impaired at ComEd in 2004 or later periods, and such impairment may be significant. Under current accounting standards, a goodwill impairment at ComEd may not affect Exelon's consolidated financial results.

Longer term, restructuring in the U.S. electric industry is at a crossroads at both the Federal and state levels, with continuing debate at the FERC on regional transmission organization (RTO) and standard market platform issues and in many states on the "post transition" format. Some states abandoned failed transition plans (like California), some states are adjusting current transition plans (like New Jersey and Ohio), and the states of Illinois (by 2007) and Pennsylvania (by 2011) are considering options to preserve choice for large customers and rate stability for mass market customers, while ensuring the financial returns needed for continuing investments in reliability. We will continue to be an active participant in these policy debates, while continuing to focus on improving operations, controlling costs and providing a fair return to our investors.

As we look towards the end of the restructuring transition periods and related rate caps or freezes in Illinois and Pennsylvania, we will also continue to work with Federal and state regulators, state and local governments, customer representatives and other interested parties to develop appropriate processes for establishing future rates in restructured electricity markets. We will strive to ensure that future rate structures recognize the substantial improvements we have made, and will continue to make, in our transmission and distribution systems. We will also work to ensure that ComEd's and PECO's rates adequately compensate our suppliers, which could include Generation, for the costs associated with procuring full-load following capacity energy supplies given Energy Delivery's Provider of Last Resort (POLR) obligations. As in the past, by working together with all interested parties, we believe we can successfully meet these objectives and obtain fair recovery of our costs for providing service to our customers. However, if we are unsuccessful, our results of operations and cash flows could be negatively affected after the transition periods.

While the U.S. economic recovery appears underway, our current plans are based on moderate kilowatthour sales growth (1% to 2%) and continued softness in wholesale power markets. Successful implementation of The Exelon Way is needed to offset labor and material cost escalation, especially the double digit increases in health care costs. Despite these challenges, our diverse mix of generation (nuclear, coal, purchased power, natural gas, hydroelectric, wind and other renewables) linked to a stable base of over five million customers will provide a solid platform from which we will strive to meet these challenges.

BUSINESS OUTLOOK AND THE CHALLENGES IN MANAGING OUR BUSINESS

Substantially all of our businesses are in the electric generation, transmission and distribution industry in the United States. That industry is in the midst of a fundamental and, at this point, uncertain transition from a fully regulated industry offering bundled service to an industry with unbundled services, some of which are regulated and others of which are priced in competitive markets. Our energy delivery business remains highly regulated while our generation and enterprises businesses operate in competitive environments. All of our businesses are capital intensive.

The challenges affecting our businesses are discussed below. There are several factors, such as weather, economic activity and regulatory actions that affect our businesses 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. Further discussion of our liquidity and capital resources and related challenges is included in the Liquidity and Capital Resources section.

Energy Delivery

Our energy delivery business is comprised of two utility transmission and distribution companies, ComEd and PECO, which provide electricity and, in the case of PECO, natural gas to customers in Illinois and Pennsylvania, respectively. Energy Delivery focuses on providing safe and reliable services to customers. Energy Delivery continues to make improvements to its delivery systems to minimize the frequency and duration of service interruptions, while working more efficiently to lower their costs. We believe that Energy Delivery will continue to provide a significant and steady source of earnings and cash flows over the next several years.

Both Illinois and Pennsylvania have adopted restructuring legislation designed to foster competition in the retail sale of electricity. As a result of these restructuring initiatives, both ComEd and PECO are subject to rate freezes or caps through mandated restructuring transition periods. During these periods, the results of operations of ComEd and PECO will depend on our ability to deliver energy in a cost-efficient manner and to offset infrastructure investments and inflation with cost savings initiatives. ComEd and PECO each expect to continue to have long-term, full-requirements supply contracts with Generation, helping to mitigate the risk of changing energy supply costs during their respective transition periods. We are also managing operations and maintenance costs by implementing The Exelon Way business model, while maintaining our focus on both reliability and safety in operating our business.

We cannot currently predict the frameworks that will be used by the Illinois and Pennsylvania state regulators to establish rates after the transition periods. We also cannot predict the outcome of any new laws that may impact our business. Nevertheless, we expect ComEd and PECO will retain significant POLR obligations, whereby each utility is required to provide service to customers in its service area. ComEd and PECO therefore must continue to ensure adequate supplies of electricity and gas are available at reasonable costs. While ComEd and PECO do not have their own generation capabilities, their ongoing relationship with Generation will serve to lessen the supply and price risks associated with their expected ongoing power procurement responsibilities.

More detailed explanations for each of these and other challenges in managing our energy delivery business are as follows:

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 ICC, and PECO is regulated by the 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 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, the costs of our operations, and the level of rates we may charge to recover such costs.

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

Rate freezes or caps in effect at ComEd and PECO currently limit our 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 under The Exelon Way 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 in effect until January 1, 2007. Pursuant to a Merger-related settlement agreement with the PUC, PECO is subject to agreed-upon rate reductions of $200 million, in aggregate, for the period 2002 through 2005, including $80 million, in aggregate, for the years 2004 and 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, and on its generation rates through December 31, 2010.

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 2004 through 2006.

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

To effectively manage its obligation to provide power to meet its customers' demand, Energy Delivery has established full-requirements, power supply agreements with Generation which reduce exposure to the volatility of customer demand and market prices through 2006 for ComEd and through 2010 for PECO. Market prices relative to Energy Delivery's regulated rates still influence switching behavior among retail customers.

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.

We expect to continue to make significant capital expenditures to improve the reliability of our transmission and distribution systems in order to provide a high level of service to its customers. We further expect Energy Delivery's capital expenditures 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.

Our business may be significantly affected by the end of the Illinois and Pennsylvania regulatory transition periods.

Illinois electric utilities are allowed to collect competitive transition charges (CTCs) from customers who choose an alternative supplier of electric generation service or choose ComEd's power purchase option (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 market value of delivered energy (the sum of generation service at market-based 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.

In 2003 and 2002, ComEd collected approximately $300 million of CTC revenue annually. As a result of increasing mitigation factors, changes in energy prices and the ability of certain customers to establish fixed, multi-year CTC rates beginning in 2003, we anticipate that this revenue source will decline to approximately $180 million to $200 million in each of the years 2004 through 2006. Under the current restructuring statute, no CTCs will be collected after 2006.

Through 2006, ComEd will continue to have an obligation to offer bundled service to all customers (except certain large customers with demand of three megawatts or more) at frozen price levels, under which a majority of ComEd's residential and small commercial customers are expected to continue to receive service. 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. 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.

In order to address post-transition uncertainty, we are continually working with Illinois state and business community leadership to facilitate the development of a competitive electricity market while providing system reliability. 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 and we are pursuing measures that will provide greater productivity, quality and innovation in our work practices across Exelon. Currently, it is difficult to predict the framework for or the outcome of a potential regulatory proceeding to establish rates after 2006.

In Pennsylvania, the Pennsylvania Electricity Generation Customer Choice and Competition Act (Competition Act) provides for the imposition and collection of non-bypassable CTCs on customers' bills as a mechanism for utilities to recover their allowed stranded costs. CTCs are assessed to and collected from virtually all retail customers who access PECO's transmission and distribution systems. These CTCs are assessed regardless of whether the customer purchases electricity from PECO or an alternative electric generation supplier. The Competition Act provides, however, that PECO'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 over a twelve-year period ending December 31, 2010, with a return on the unamortized balance of 10.75%. At December 31, 2003, approximately $4.3 billion had yet to be recovered. Recovery of transition charges for stranded costs and PECO's allowed return on its recovery of stranded costs are included in revenues. Amortization of PECO's stranded cost recovery, which is a regulatory asset, is included in depreciation and amortization expense. PECO's results will be adversely affected over the remaining transition period ending December 31, 2010 by the steadily increasing amortization of stranded costs. The following table (amounts in millions) indicates the estimated revenues and amortization expense associated with CTC collection and stranded cost recovery through 2010.

Year	Estimated CTC Revenue	Estimated Stranded Cost Amortization
2004	$ 812	$ 367
2005	808	404
2006	903	550
2007	910	619
2008	917	697
2009	924	783
2010	932	880

By the end of 2010, PECO will have fully recovered all of the stranded costs authorized by the PUC. As a result, PECO expects that both its revenues and expenses will decrease in 2011. The end of the transition period involves uncertainties, including the nature of PECO's POLR obligations and the source and pricing of generation services to be provided by PECO. PECO expects to pursue resolution of these uncertainties during the remaining transition period.

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

ComEd has approximately $4.7 billion of goodwill recorded at December 31, 2003. This goodwill was recognized and recorded in connection with the Merger. Under accounting principles generally accepted in the Unites States (GAAP), the goodwill will remain at its recorded amount unless it is determined to be impaired, which is based upon an annual analysis prescribed by SFAS No. 142, "Goodwill and Other Intangible Assets" (SFAS No. 142) that compares the implied fair value of the goodwill to its carrying value. If an impairment is determined at ComEd, the amount of the impaired goodwill will be written off and expensed at ComEd. Under Illinois statute, any impairment of goodwill has no impact on the determination of ComEd's rate cap through the transition period.

ComEd's goodwill has not been impaired to date. However, based on certain anticipated reductions to cash flows (primarily CTCs) subsequent to ComEd's regulatory transition period, we believe there is a reasonable possibility that goodwill will be impaired at ComEd in 2004 or later periods. The actual timing and amounts of any goodwill impairments in future years, if any, will depend on many sensitive, interrelated and uncertain variables, including changing interest rates, utility sector market performance, ComEd's capital structure, market power prices, post-2006 rate regulatory structures, operating and capital expenditure requirements and other factors, some not yet known. A goodwill impairment charge at ComEd may not affect Exelon's results of operations as the goodwill impairment test for Exelon would consider cash flows of the entire Energy Delivery business segment, including both ComEd and PECO, and not just of ComEd. See Critical Accounting Policies and Estimates for further discussion on goodwill impairments.

We are and will continue to be involved in 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 or even reducing rates. 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 grants some certainty to all parties to the proceedings as to rates and energy costs.

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

Increases in both customers and the demand for energy require 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. We cannot predict what impact these failures, or failures that impact other utilities such as the August Blackout, will have on our anticipated capital expenditures.

Although neither ComEd nor PECO was directly affected by the August Blackout, we may be indirectly affected going forward. Regulated utilities that are required to provide service to all customers within their service territory have generally been afforded liability protections against claims by customers relating to failure of service. Following the August Blackout, significant claims have been asserted against various other utilities on behalf of both customers and non-customers for damages resulting from the blackout. We cannot predict whether these claims will be upheld or whether they or legislative or regulatory initiatives in response to the August Blackout will change the traditional liability protections of utilities in providing regulated service. 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.

Energy Delivery has lost and may continue to lose energy customers to other generation suppliers, 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 may purchase their generation supply from alternative electric generation suppliers. In addition, since market share thresholds (MST) for customers taking service from alternative generation suppliers agreed to by PECO were not met, PECO has been required to assign both commercial and residential customers to alternative generation suppliers. ComEd and PECO are each 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 take service from 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 suppliers. The number of customers taking service from 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. To the extent that customers leave traditional bundled tariffs and select a different generation supplier, Energy Delivery's revenues are likely to decline, and our revenues and gross margins could vary from period to period.

Energy Delivery continues to serve as the POLR for energy for all customers in its service territories. Since ComEd and PECO customers can "switch," that is, within limits they can choose an alternative generation supplier and then return to us and then go back to an alternative supplier, and so on, planning for Energy Delivery has a higher level of uncertainty than that traditionally experienced due to weather and the economy. Energy Delivery has no obligation to purchase power reserves to cover the load served by others. We manage our POLR obligation through full-requirements contracts with Generation, under which Generation supplies the power requirements of ComEd and PECO.

ComEd has received ICC approval to phase out its obligation to provide fixed-price energy under bundled rates to approximately 350 of its largest energy customers, which ComEd believes partially mitigates its risk. 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 MWs representing an aggregate of approximately 2,500 MWs of load. These customers accounted for 10% of ComEd's 2003 MWh deliveries.

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 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 average use of energy. Periods of recessionary economic conditions may adversely affect our results of operations. In the near term, retail sales growth on an annual basis is expected to be 1.2% and 1.3% in the service territories of ComEd and PECO, respectively. Long-term retail sales growth for electricity is expected to be 1.5% and 1.0% per year for ComEd and PECO, respectively.

Energy Delivery's 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, the August Blackout and the 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.

Regional Transmission Organizations and Standard Market Platform. The FERC has required jurisdictional utilities to provide open access to their transmission systems. It has also sought the voluntary development of RTOs and the elimination of trade barriers between regions. The FERC also proposed rulemakings to implement protocols to create a standard wholesale market platform for the wholesale markets for energy and capacity. The RTO would become the provider of the transmission service, and the transmission owners would recover their revenue requirements through it. The transmission owners would remain responsible for maintaining and physically operating their transmission facilities. The wholesale market platform 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 manage congestion on transmission lines preferably by means of a financially based system known as "locational marginal pricing." FERC is likely to finalize its wholesale market platform rule during 2004.

PECO is a member of PJM Interconnection, LLC (PJM), an approved RTO operating in the Mid-Atlantic region. ComEd and other Midwestern utilities are seeking to become fully integrated into the PJM RTO in 2004. When ComEd integrates into PJM, ComEd will recover its current transmission revenues through the PJM open-access transmission tariff (OATT), instead of ComEd's own OATT.

The FERC's RTO and standard market platform initiatives have generated substantial opposition by some state regulators and other governmental bodies. In addition, efforts to develop an RTO have been abandoned in certain regions. We support both of these FERC initiatives 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, the ability of ComEd and PECO to cost effectively serve their POLR load obligations may depend on successful spot markets in their franchised service territories.

Proposed Federal Energy Legislation. One of the principal legislative initiatives of the Bush administration is the adoption of comprehensive Federal energy legislation. In 2003, an energy bill was passed by the U.S. House of Representatives but was not voted on by the U.S. Senate. The energy bill, as currently written, would repeal the Public Utility Holding Company Act of 1935 (PUHCA), create incentives for the construction of transmission infrastructure, encourage but not mandate standardized competitive markets and expand the authority of the FERC to include overseeing the reliability of the bulk power system. We cannot predict whether comprehensive energy legislation will be adopted and, if adopted, the final form of that legislation. We would expect that comprehensive energy legislation would, if adopted, significantly affect the electric utility industry and our businesses.

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. Generation's Power Team 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.

Generation must effectively manage its power portfolio to meet its contractual commitments and to handle changes in the wholesale power markets.

The majority of Generation's portfolio is used to provide power under long-term purchased power agreements with ComEd and PECO. To the extent the portfolio is not needed for that purpose, Generation's output is sold on the wholesale market. Generation's financial results are dependent upon its ability to cost-effectively meet the load requirements of ComEd and PECO, to manage its power portfolio and to effectively handle the changes in the wholesale power markets.

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

Generation's resources include interests in 11 nuclear generation stations, consisting of 19 units. Generation's nuclear fleet, excluding AmerGen's three units, generated 117,502 GWhs, or more than half of our total available generating capacity, as of December 31, 2003. As the largest generator of nuclear power in the United States, Generation can take advantage of its 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 may be affected by liabilities arising from Generation's ownership and operation of nuclear facilities.

The ownership and operation of nuclear facilities involve risks, including:

- mechanical or structural problems;
- inadequacy or lapses in maintenance protocols;
- impairment of reactor operation and safety systems due to human error;
- costs of storage, handling and disposal of nuclear materials;
- limitations on the amounts and types of insurance coverage commercially available; and
- uncertainties regarding both technological and financial aspects of decommissioning nuclear facilities at the end of their useful lives.

The material risks known or currently anticipated by us that could affect our ability to sustain our current levels of profitability are:

Nuclear capacity factors. 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 variable costs due to low fuel costs. Consequently, to be successful, Generation must consistently operate its nuclear generating facilities at high capacity factors. Lower capacity factors would increase Generation's 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 Generation's obligations to ComEd and PECO and other committed third-party sales. These sources generally are at a higher cost than Generation otherwise would have to incur to generate energy from its nuclear stations.

Refueling outages. 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 26 days in duration. Generation has significantly decreased the length of refueling outages in recent years. However, when refueling outages last longer than anticipated or Generation experiences unplanned outages, Generation faces lower margins due to higher energy replacement costs and/or lower energy sales. Each twenty-six day outage, depending on the capacity of the station, will decrease the total nuclear annual capacity factor between 0.3% and 0.5%. The number of refueling outages, including AmerGen, will increase to ten in 2004 from nine in 2003. Maintenance expenditures are expected to increase by approximately $20 million in 2004 as compared to 2003 as a result of increased nuclear refueling outages.

Nuclear fuel quality. The quality of nuclear fuel utilized by Generation can affect the efficiency and costs of our operations. Certain of Generation's nuclear units have been identified as having a limited number of fuel performance issues. Remediation actions, including those required to address performance issues, have resulted in increased costs due to accelerated fuel amortization and/or increased outage costs and could continue to do so. It is difficult to predict the total cost of these remediation procedures.

Life extensions. Generation's nuclear facilities are currently operating under 40-year Nuclear Regulatory Commission (NRC) licenses. Generation has applied for 20-year extensions for the licenses that will be expiring in the next ten years, excluding licenses for the AmerGen facilities. We anticipate filing a request for a license extension for Oyster Creek and are evaluating the other AmerGen facilities for possible extension. Generation has received a 20-year extension of the license for the Peach Bottom units, but Generation cannot predict whether any of the other pending extensions will be granted. Generation intends to evaluate opportunities, as permitted by the NRC, to apply for life extensions to some or all of the remaining licenses. If the extensions are granted, Generation cannot be sure that it will be willing to operate the facilities for all or any portion of the extended license. If the NRC does not extend the operating licenses for Generation's nuclear stations, our results of operations could be adversely affected by increased depreciation rates and accelerated future decommissioning payments.

Regulatory risk. The NRC may modify, suspend or revoke licenses, shut down a nuclear facility and impose civil penalties for failure to comply with the Atomic Energy Act, related regulations or the terms of the licenses for nuclear facilities. A change in the Atomic Energy Act or the applicable regulations or licenses may require a substantial increase in capital expenditures or may result in increased operating or decommissioning costs and significantly affect our results of operation or financial position. Events at nuclear plants owned by others, as well as those owned by Generation, may cause the NRC to initiate such actions.

Operational risk. Operations at any of Generation's nuclear generation plants could degrade to the point where Generation has to shut down the plant or operate at less than full capacity. If this were to happen, identifying and correcting the causes may require significant time and expense. Generation may choose to close a plant rather than incur the expense of restarting it or returning the plant to full capacity. In either event, Generation may lose revenue and incur increased fuel and purchased power expense to meet supply commitments. For plants operated but not wholly owned by Generation, Generation may also incur liability to the co-owners.

Nuclear accident risk. Although the safety record of nuclear reactors, including Generation's, generally 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 include loss of life and property damage. Any resulting liability from a nuclear accident may exceed our resources, including insurance coverages, and significantly affect our results of operation or financial position.

Nuclear liability insurance. The Price-Anderson Act limits the liability of nuclear reactor owners for claims that could arise from a single incident. The limit as of January 1, 2004 is $10.9 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 the maximum available amount of nuclear liability insurance (currently $300 million for each operating site). Claims exceeding that amount are covered through mandatory participation in a financial protection pool. The Price-Anderson Act expired on August 1, 2002 and was subsequently extended to the end of 2003 by the U.S. Congress. Only facilities applying for NRC licenses subsequent to expiration of the Price-Anderson Act are affected. Existing commercial generating facilities, such as those owned and operated by Generation, remain subject to the provisions of the Price-Anderson Act and are unaffected by its expiration.

Decommissioning. Generation has an obligation to decommission its nuclear power plants. Based on estimates of decommissioning costs for each of the nuclear facilities in which Generation has an ownership interest, other than AmerGen facilities, the ICC permits ComEd, and the PUC permits PECO, to collect from their customers and deposit in nuclear decommissioning trust funds maintained by Generation amounts which, together with earnings thereon, will be used to decommission such nuclear facilities. The ICC permitted ComEd to recover $73 million per year from retail customers for decommissioning for the years 2001 through 2004, and, depending upon the portion of the output of certain generating stations taken by ComEd, up to $73 million annually in 2005 and 2006. Subsequent to 2006, there will be no further recoveries of decommissioning costs from ComEd's customers. Effective January 1, 2004, PECO will be permitted to recover $33 million annually for nuclear decommissioning. We expect that these collections will continue through the operating license life of each of the former PECO units, with adjustments every five years to reflect changes in cost estimates and decommissioning trust fund performance. Decommissioning expenditures are expected to occur primarily after the plants are retired and are currently estimated to begin in 2029 for plants currently in operation. To fund future decommissioning costs, Generation held $4.7 billion of investments in trust funds, including net unrealized gains and losses, at December 31, 2003.

NRC regulations require that licensees of nuclear generating facilities demonstrate reasonable assurance that funds will be available in certain minimum amounts at the end of the life of the facility to decommission the facility. Generation is required to provide to the NRC a biennial report by unit (annually for Generation's four retired units) addressing Generation's ability to meet the NRC estimated funding levels (NRC Funding Levels) with scheduled contributions to and earnings on the decommissioning trust funds. As of December 31, 2003, Generation had a number of units, which, at current market levels, are being funded at a rate less than anticipated with respect to the NRC's Funding Levels. Generation will submit its next biennial report to the NRC at the end of March 2005. At that time, Generation will address potential actions, in accordance with NRC requirements, to assure that Generation will remain adequately funded compared to the NRC Funding Levels.

In 2003, the General Accounting Office (GAO) published a study on the NRC's need for more effective analyses to ensure the adequate accumulation of funds to decommission nuclear power plants in the United States. As it has in the past, the GAO concluded that accumulated and future proposed funding was inadequate to achieve NRC Funding Levels at a number of U.S. nuclear plants, including a number of Generation's plants. Generation has reviewed the GAO's report and believes that, in reaching its conclusions, the GAO did not consider all aspects of Generation's decommissioning strategy, such as fund growth during the decommissioning period. The inclusion of estimated earnings growth on Generation's nuclear trust funds during the decommissioning period virtually eliminates any funding shortfalls identified in the GAO report.

In spite of any temporary shortfall in NRC Funding Levels, Generation currently believes that the amounts in nuclear decommissioning trust funds and future collections from ratepayers, together with earnings thereon, will provide adequate funding to decommission its nuclear facilities in accordance with regulatory requirements. Forecasting investment earnings and costs to decommission nuclear generating stations requires significant judgment, and actual results may differ significantly from our current estimates. Ultimately, when decommissioning activities are initiated, if the investments held by Generation's nuclear decommissioning trusts are not sufficient to fund the decommissioning of Generation's nuclear plants, Generation may be required to identify other means of funding its decommissioning obligations.

Generation relies on electric transmission facilities that it does not own or control. If operations at these facilities are disrupted or do not provide Generation with adequate transmission capacity, it may not be able to deliver its wholesale electric power to the purchasers of the power.

Generation depends on transmission facilities owned and operated by other companies, including ComEd and PECO, to deliver the power that it sells at wholesale. If transmission at these facilities is disrupted, or transmission capacity is inadequate, Generation may not be able to sell and deliver its wholesale power. While Generation was not significantly affected by the failure in the transmission grid that served a large portion of the Northeastern United States and Canada during the August Blackout, the North American transmission grid is highly interconnected and, in extraordinary circumstances, disruptions at a point within the grid can cause a systemic response that results in an extensive power outage. If a region's power transmission infrastructure is inadequate, our recovery of wholesale costs and profits may be limited. In addition, if restrictive transmission price regulation is imposed, the transmission companies may not have sufficient incentive to invest in expansion of transmission infrastructure.

The FERC has issued electric transmission initiatives that require electric transmission services to be offered unbundled from commodity sales. Although these initiatives are designed to encourage wholesale market transactions for electricity, access to transmission systems may in fact not be available if transmission capacity is insufficient because of physical constraints or because it is contractually unavailable. We also cannot predict whether transmission facilities will be expanded in specific markets to accommodate competitive access to those markets.

Generation is directly affected by price fluctuations and other risks of the wholesale power market.

Generation fulfills its energy commitments from the output of the generating facilities that it owns as well as through buying electricity in both the wholesale bilateral and spot markets. The excess or deficiency of energy owned or controlled by Generation compared to its obligations exposes Generation to the risks of rising and falling prices in those markets, and Generation's cash flows may vary accordingly. Generation's cash flows from its generation portfolio that is not used to meet its commitments to ComEd and PECO are largely dependent on wholesale prices of electricity and Generation's ability to successfully market energy, capacity and ancillary services. In the event that lower wholesale prices of electricity reduce Generation's current or forecasted cash flows, the carrying value of Generation's generating units may be determined to be impaired and Generation would be required to incur an impairment loss.

The wholesale spot market price of electricity for each hour is generally determined by the cost of supplying the next unit of electricity to the market during that hour. 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 natural gas plus the cost to convert natural gas to electricity. Therefore, changes in the supply and cost of natural gas generally impact the open market wholesale price of electricity.

Credit Risk. In the bilateral markets, Generation is exposed to the risk that counterparties that owe Generation money or energy will not perform their obligations. For example, energy supplied by third-party generators, including Sithe, under long-term agreements represents a significant portion of Generation's overall capacity. These generators face operational risks, such as those that Generation faces, and their ability to perform depends on their financial condition. In the event the counterparties to these arrangements fail to perform, Generation might be forced to purchase or sell power in the wholesale markets at less favorable prices and incur additional losses, to the extent of amounts, if any, already paid to the counterparties. In the spot markets, Generation is exposed to the risks of whatever default mechanisms exist in that market, some of which attempt to spread the risk across all participants, which may or may not be an effective way of lessening the severity of the risk and the amounts at stake. We are also a party to agreements with entities in the energy sector that have experienced rating downgrades or other financial difficulties.

In order to evaluate the viability of Generation's counterparties, Generation has implemented credit risk management procedures designed to mitigate the risks associated with these transactions. These policies include counterparty credit limits and, in some cases, require deposits or 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.

Immature Markets. The wholesale spot markets are new and evolving markets that vary from region to region and are still developing practices and procedures. While the FERC has proposed initiatives to standardize wholesale spot markets, we cannot predict whether that effort will be successful, what form any of these markets will eventually take or what roles we will play in them. Problems in or the failure of any of these markets, as was experienced in California in 2000, could adversely affect our business.

Hedging. The Power Team buys and sells energy and other products in the wholesale markets and enters into financial contracts to manage risk and hedge various positions in Generation's power generation portfolios. This activity, along with the effects of any specialized accounting for trading contracts, may cause volatility in our future results of operations.

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

Excess capacity. Energy prices are also affected by the amount of supply available in a region. In the markets where Generation sells power, there has been a significant increase in the number of new power plants commencing commercial operations which has driven down power prices over the last few years. In fact, an excess supply situation currently exists in many parts of the country which has reduced prices in the wholesale markets and adversely affected Generation's profitability. We cannot predict when these regions will return to more normal levels in the supply-demand balance.

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

Regional Transmission Organizations and Standard Market Platform. Generation is dependent on wholesale energy markets and open transmission access and rights by which Generation delivers power to its wholesale customers, including ComEd and PECO. Generation uses the wholesale regional energy markets to sell power that Generation does not need to satisfy its long-term contractual obligations, to meet long-term obligations not provided by its own resources and to take advantage of price opportunities.

Wholesale markets have only been implemented in certain areas of the country and each market has unique features which may create trading barriers among the markets. The FERC has proposed initiatives, including FERC Order No. 2000 and the proposed wholesale market platform rule, to encourage the development of large regional, uniform markets and to eliminate trade barriers. These initiatives, however, have not yet led to the development of such markets in all areas of the country. PJM's and the New England markets strongly resemble the FERC's proposal, and the New York Independent System Operator (ISO) is implementing market reforms. We support the development of standardized energy markets and the 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 27% of Generation's generating resources, which include directly owned assets and capacity obtained through long-term contracts, are located in the region encompassed by PJM. If the PJM market is expanded to the Midwest, 79% of Generation's generating resources would be located within that market. The PJM market has been the most successful and liquid regional market. Our future results of operations may be affected by the successful expansion of that market to the Midwest and the implementation of any market changes mandated by the FERC.

Provider of Last Resort. As discussed above, ComEd and PECO each have POLR obligations that they have effectively transferred to Generation through full-requirements contracts. Because the choice of electricity generation supplier lies with the customer, planning to meet these obligations has a higher level of uncertainty than that traditionally experienced due to weather and the economy. It is difficult for Generation to plan the energy demand of ComEd and PECO customers. The uncertainty regarding the amount of ComEd and PECO load for which Generation must prepare increases our costs and may limit our sales opportunities. A significant under-estimation of the electric-load requirements of ComEd and PECO could result in Generation not having enough power to cover its supply obligation, in which case Generation would be required to buy power from third parties or in the spot markets at prevailing market prices. Those prices may not be as favorable or as manageable as Generation's long-term supply expenses and thus could increase our total costs.

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. The inability of Generation to effectively manage its capital projects could adversely affect our results from operations.

In 2002, Generation purchased the assets of Sithe New England Holdings, LLC (now known as Exelon New England), a subsidiary of Sithe, and related power marketing operations. Due to the reduction in power prices and delays in construction completion, in July 2003, we commenced the process of an orderly transition out of the ownership of the Boston Generating assets.

We recorded an impairment charge of $945 million before income taxes related to the long-lived assets of Boston Generating as a result of our decision to exit these facilities. Charges could result from decisions to exit other investments or projects in the future. These charges could have a significant impact on our results of operations.

The interaction between our energy delivery and generation businesses provides us a partial hedge of wholesale energy market prices.

The price of power purchased and sold in the open wholesale energy markets can vary significantly in response to market conditions. The amounts of power that Generation provides to ComEd and PECO 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 by Generation to serve ComEd and PECO customers is not exposed to the price uncertainty of the open wholesale energy market. Generally, between 60% and 70% of our generation supply serves ComEd and PECO customers. Consequently, we have limited our earnings exposure from the volatility of the wholesale energy market to the energy generated in excess of the ComEd and PECO requirements, as well as any other contracted longer term obligations.

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. These new generating facilities may be more efficient than our facilities. The introduction of new technologies could increase competition, which could lower prices and have an adverse effect on our results of operations or financial condition. Our financial performance depends on our ability to respond to competition in the energy industry.

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

Our results of operations may be affected by our ability to strategically divest certain businesses.
We are actively pursuing opportunities to dispose of businesses, such as our investment in Sithe, which are either unprofitable or do not advance our strategic goals. We may incur significant costs in divesting these businesses. We also may be unable to successfully implement our 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. The inability to divest certain businesses could negatively affect our results of operations. In addition, the amounts that we may realize from a divestiture are subject to fluctuating market conditions that may contribute to pricing and other terms that may be materially different than expected and could result in losses on sales.

Enterprises

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

Enterprises' results of operations may be affected by its ability to strategically divest 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 transactions. In addition, the amount that Enterprises may realize from a divestiture is subject to fluctuating market conditions that may contribute to pricing and other terms that may be materially different than expected and could result in losses on sales. Enterprises also faces risks in managing these businesses prior to their divestitures due to potential turnover of key employees and operating the businesses through their transition.

Enterprises may incur further impairment charges.
Enterprises recorded impairment charges totaling $140 million during 2003 associated with investments, goodwill and other assets.

At December 31, 2003, Enterprises had total assets of $831 million, of which $214 million are under contract to be sold in 2004. Enterprises may incur further impairment charges in connection with the ultimate disposition of these assets.

Enterprises' results of operations may be affected by its ability to manage its projects.
Enterprises includes certain 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 from the estimates, our results of operations will be adversely affected. Along with our ability to manage our projects, results may also be affected by economic conditions, weather conditions, the inability to attract and retain qualified management due to planned divestiture of these businesses and the regulatory environment. In connection with the sale or wind down of certain businesses of Enterprises in 2003, Enterprises has retained risk of loss for certain long-term fixed-price contracts that have been subcontracted to third parties. If unanticipated losses are incurred on these contracts in future periods, our results of operations may be adversely affected.

General Business

Our financial performance will be affected by our ability to achieve the targeted cash savings under The Exelon Way business model.

We have begun to implement The Exelon Way business model, which is focused on improving operating cash flows while meeting service and financial commitments through improved integration of operations and consolidation of support functions. Our targeted annual cash savings range from approximately $300 million in 2004 to approximately $600 million in 2006. We have incurred and are considering whether there are additional expenses, including employee severance costs, associated with reaching these annual cash savings levels. Our targeted annual cash savings do not reflect any expenses that may be incurred in future periods. Our inability to realize these annual cash savings levels in the targeted timeframes could adversely affect our future financial performance.

Our results of operations are affected by inflation.

Inflation affects us through increased operating costs and increased capital costs for plant and equipment. As a result of the rate freezes and caps under which our Energy Delivery businesses operate and price pressures due to competition, we may not be able to pass the costs of inflation through to our customers.

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

The performance of the capital markets affects the values of the assets that are held in trust to satisfy our future obligations under our pension and postretirement benefit plans and to decommission our nuclear generation plants. We have significant obligations in these areas and hold significant assets in these trusts. A decline in the market value of those assets, as was experienced from 2000 to 2002, may increase our funding requirements of these obligations.

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 PUHCA 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 and for ComEd and PECO, requiring the approval of state regulatory commissions;
- 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 increasing costs associated with additional security measures and obtaining adequate liability insurance.

Security. We do not know the impact that future terrorist attacks or threats of terrorism may have on our industry in general and on us in particular. We have initiated security measures to safeguard our employees and critical operations from threats of terrorism and are actively participating in industry initiatives to identify methods to maintain the reliability of our energy production and delivery systems. We fully expect to meet or exceed all NRC-mandated measures on or before the dates specified by requirements promulgated in 2003. These requirements will necessitate additional security expenditures in 2004. Additionally, we are in full compliance with all pre-2003 NRC security measures. 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.

The electric and gas industries have also developed additional security guidelines as the result of various terrorist attacks or threats of terrorism. The electric industry, through the North American Electric Reliability Council, developed physical security guidelines, which were accepted by the U.S. Department of Energy. In 2003, the FERC issued 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.

Insurance. In addition to nuclear liability insurance, we also carry property damage and liability insurance for our properties and operations. As a result of significant changes in the insurance marketplace, due in part to 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 terrorist 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 2003 was $32 million, which was recorded as a reduction to operating and maintenance expenses in our Consolidated Statement of Income. We cannot predict the level of future distributions or if they will continue at all.

We may incur substantial costs 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 our 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, site remediation and clean-up. Remediation activities associated with manufactured gas plant operations conducted by predecessor companies will be one component 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, 2003, our reserve for environmental investigation and remediation costs was $129 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.

Taxation has a significant impact on our results of operations.

Tax reserves and the recoverability of our deferred tax assets. We are required to make judgments regarding the potential tax effects of various financial transactions and our ongoing operations to estimate our obligations to taxing authorities. These tax obligations include income, real estate, use and employment-related taxes and ongoing appeals related to these tax matters. These judgments include reserves for potential adverse outcomes regarding tax positions that we have taken. We must also assess our ability to generate capital gains in future periods to realize tax benefits associated with capital losses expected to be generated in future periods. Capital losses may be deducted only to the extent of capital gains realized during the year of the loss or during the three prior or five succeeding years. As of December 31, 2003, we have not recorded an allowance against our deferred tax assets associated with impairment losses which will become capital losses when realized for income tax purposes. We believe these deferred tax assets will be realized in future periods. The ultimate outcome of such matters could result in adjustments to our consolidated financial statements and such adjustments could be material.

Increases in state income taxes. Due to the revenue needs of the states in which we operate, various state income tax and fee increases have been proposed or are being contemplated. We cannot predict whether legislation or regulation will be introduced, the form of any legislation or regulation, whether any such legislation or regulation will be passed by the state legislatures or regulatory bodies, and, if enacted, whether any such legislation or regulation would be effective retroactively or prospectively. If enacted, these changes could increase our state income tax expense and could have a negative impact on our results of operations and cash flows.

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 generating 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 effect on our results of operations or financial condition.

We may make acquisitions that do not achieve the intended financial results.

We continue to opportunistically pursue investments that fit our strategic objectives and improve our financial performance. Our future performance will depend in part upon a variety of factors related to these investments, including our ability to successfully integrate them into existing operations. These new investments, as well as our existing investments, may not achieve the financial performance that we anticipate.

RESULTS OF OPERATIONS

Year Ended December 31, 2003 Compared To Year Ended December 31, 2002

Exelon Corporation	**2003**	2002	Variance	% Change
Operating revenues	**$15,812**	$14,955	$ 857	5.7%
Purchased power and fuel expense	**6,375**	5,262	1,113	21.2%
Operating and maintenance expense	**5,532**	4,345	1,187	27.3%
Operating income	**2,198**	3,299	(1,101)	(33.4%)
Other income and deductions	**(1,074)**	(631)	(443)	70.2%
Income before income taxes and cumulative effect of changes in accounting principles	**1,124**	2,668	(1,544)	(57.9%)
Income before cumulative effect of changes in accounting principles	**793**	1,670	(877)	(52.5%)
Net income	**905**	1,440	(535)	(37.2%)
Diluted earnings per share	**2.75**	4.44	(1.69)	(38.1%)

Net Income. Net income for 2003 reflects income of $112 million, net of income taxes, for the adoption of SFAS No. 143, "Asset Retirement Obligations" (SFAS No. 143), while net income for 2002 reflects a $230 million charge, net of income taxes, as a result of the adoption of SFAS No. 142. See Note 1 of the Notes to Consolidated Financial Statements for further information regarding the adoptions of SFAS No. 143 and SFAS No. 142.

Operating Revenues. Operating revenues increased in 2003 primarily due to increased market sales at Generation due to generating assets acquired in 2002 and higher wholesale market prices in 2003. Total market sales at Generation, excluding the trading portfolio, increased from 83,565 GWhs in 2002 to 107,267 GWhs in 2003, and the average revenue per MWh on Generation's market sales, excluding the trading portfolio, increased from $31.01 in 2002 to $35.99 in 2003. This increase was partially offset by a decrease in Energy Delivery's revenues of $255 million primarily due to unfavorable weather impacts and an increase in customers selecting an alternative retail electric supplier (ARES) or ComEd's PPO. Enterprises also experienced a $276 million reduction in operating revenues from 2002 to 2003, primarily due to the sale of InfraSource during the third quarter of 2003. See further discussion of operating revenues by segment below.

Purchased Power and Fuel Expense. Purchased power and fuel expense increased in 2003 primarily due to generating assets acquired in 2002 and higher market prices for purchased power in 2003. The average cost per MWh supplied by Generation, excluding the trading portfolio, increased from $20.49 in 2002 to $22.79 in 2003 due to increased fossil generation and increased purchased power at higher market prices. Fossil and hydroelectric generation represented 11% of Generation's total supply in 2003 compared to 6% in 2002. See further discussion of purchased power and fuel expense by segment below.

Operating and Maintenance Expense. Operating and maintenance expense increased in 2003 primarily due to a change in the accounting methodology for nuclear decommissioning, severance and severance-related costs associated with The Exelon Way, and increased costs at Generation associated with generating assets acquired in 2002. Partially offsetting these increases was an overall reduction in operating and maintenance expenses at Enterprises, primarily due to the sale of InfraSource during the third quarter of 2003. See further discussion of operating and maintenance expenses by segment below.

Operating Income. The decrease in operating income, exclusive of the changes in operating revenues, purchased power and fuel expense and operating and maintenance expense discussed above, was primarily due to an impairment charge of $945 million before income taxes recorded by Generation related to the long-lived assets of Boston Generating. Operating income was favorably affected by a decrease of $214 million in depreciation and amortization expense primarily due to the adoption of SFAS No. 143 and lower depreciation and amortization expense in the Energy Delivery segment. In addition, taxes other than income also decreased by $128 million primarily due to a reduction in reserves for real estate taxes within the Energy Delivery and Generation segments.

Other Income and Deductions. Other income and deductions changed primarily due to impairment and other transaction-related charges of $280 million recorded in 2003 related to Generation's investment in Sithe. Interest expense decreased 9% from $966 million in 2002 to $881 million in 2003 primarily due to less outstanding debt and refinancing of existing debt at lower interest rates at Energy Delivery partially offset by increased interest expense at Generation due to debt related to 2002 acquisitions and reduced capitalized interest in 2003. In 2002, Enterprises recorded a gain on the sale of its investment in AT&T Wireless of $198 million (before income taxes).

Results of Operations by Business Segment

The comparisons of 2003 and 2002 operating results and other statistical information set forth below reflect intercompany transactions, which are eliminated in our consolidated financial statements.

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

	2003	2002	Variance	% Change
Energy Delivery	**$1,170**	$1,268	$ (98)	(7.7%)
Generation	**(241)**	387	(628)	(162.3%)
Enterprises	**(135)**	65	(200)	n.m.
Corporate	**(1)**	(50)	49	(98.0%)
Total	**$ 793**	$1,670	$ (877)	(52.5%)

n.m. – not meaningful

Net Income (Loss) by Business Segment

	2003	2002	Variance	% Change
Energy Delivery	**$1,175**	$1,268	$ (93)	(7.3%)
Generation	**(133)**	400	(533)	(133.3%)
Enterprises	**(136)**	(178)	42	(23.6%)
Corporate	**(1)**	(50)	49	(98.0%)
Total	**$ 905**	$1,440	$(535)	(37.2%)

Results of Operations–Energy Delivery

Energy Delivery	2003	2002	Variance	% Change
Operating revenues	**$10,202**	$10,457	$(255)	(2.4%)
Purchased power and fuel expense	**4,597**	4,602	(5)	(0.1%)
Operating and maintenance expense	**1,669**	1,486	183	12.3%
Depreciation and amortization expense	**873**	978	(105)	(10.7%)
Taxes other than income	**440**	531	(91)	(17.1%)
Operating income	**2,623**	2,860	(237)	(8.3%)
Interest expense	**747**	854	(107)	(12.5%)
Income before income taxes and cumulative effect of a change in accounting principle	**1,888**	2,033	(145)	(7.1%)
Income before cumulative effect of a change in accounting principle	**1,170**	1,268	(98)	(7.7%)
Net income	**1,175**	1,268	(93)	(7.3%)

Net Income. Energy Delivery's net income in 2003 decreased primarily due to increased operating and maintenance expense resulting from severance and curtailment charges associated with The Exelon Way, a charge at ComEd associated with a regulatory settlement, lower revenues, net of purchased power primarily attributable to weather and higher purchased power prices, partially offset by reductions in depreciation and amortization expense, taxes other than income, and interest expense.

Operating Revenues. The changes in Energy Delivery's operating revenues for 2003 compared to 2002 consisted of the following:

Energy Delivery	Electric	Gas	Total Variance
Customer choice	$ (167)	$ –	$(167)
Weather	(229)	71	(158)
Resales and other	–	(22)	(22)
Rate changes and mix	(58)	51	(7)
Volume	118	(3)	115
Other effects	(15)	(1)	(16)
(Decrease) increase in operating revenues	$ (351)	$96	$(255)

Customer Choice. For 2003 and 2002, 25% and 21%, respectively, of energy delivered to Energy Delivery's retail customers was provided by alternative electric suppliers or under the ComEd PPO. The decrease in electric retail revenues attributable to customer choice included a decrease in revenues of $155 million from customers in Illinois electing to purchase energy from an ARES or ComEd's PPO and a decrease in revenues of $12 million from customers in Pennsylvania selecting or being assigned to an alternative electric generation supplier.

Weather. Energy Delivery's electric revenues were affected by cooler summer weather in 2003, partially offset by colder winter weather in the first quarter of 2003. Cooling degree-days in the ComEd and PECO service territories were 36% lower and 21% lower, respectively, in 2003 as compared to 2002. Heating degree-days in the ComEd and PECO service territories were 5% higher and 16% higher, respectively, in 2003 as compared to 2002.

Energy Delivery's gas revenues were affected by colder winter weather in the first quarter of 2003.

Resales and other. Energy Delivery's gas revenues decreased as a result of a decrease in off-system sales, exchanges and capacity releases.

Rate Changes and Mix. Energy Delivery's electric revenues decreased $33 million at ComEd primarily due to decreased average energy rates under ComEd's PPO as a result of lower wholesale market prices. Electric revenues decreased $25 million at PECO as a result of rate mix due to changes in monthly usage patterns in all customer classes during 2003 as compared to 2002.

Energy Delivery's gas revenues increased due to increases in rates through the purchased gas adjustment clause that became effective March 1, 2003, June 1, 2003 and December 1, 2003. The average purchased gas cost rate per million cubic feet for 2003 was 11% higher than the rate in 2002. PECO's purchased gas cost rates are subject to periodic adjustments by the PUC and are designed to recover from or refund to customers the difference between the actual cost of purchased gas and the amount included in rates.

Volume. Energy Delivery's electric revenues increased as a result of higher delivery volume, exclusive of the effect of weather, due to an increased number of customers and increased usage per customer, primarily in the large and small commercial and industrial customer classes.

Other. The decrease was attributable to a reduction in wholesale revenue. This reduction reflects a $12 million reimbursement from Generation in 2002.

Purchased Power and Fuel Expense. The changes in Energy Delivery's purchased power and fuel expense for 2003 compared to 2002 consisted of the following:

Energy Delivery	Electric	Gas	Total Variance
Customer choice	$(143)	$ –	$(143)
Weather	(119)	49	(70)
Resales and other	–	(28)	(28)
Prices	74	39	113
Volume	73	6	79
Decommissioning	62	–	62
Other	(23)	5	(18)
(Decrease) increase in purchased power and fuel expense	$ (76)	$ 71	$ (5)

Customer Choice. An increase in customer switching resulted in a reduction of purchased power expense, primarily due to ComEd's non-residential customers electing to purchase energy from an ARES or ComEd's PPO and PECO's non-residential customers electing or being assigned to purchase energy from alternative energy suppliers.

Weather. Energy Delivery's purchased power and fuel expense decreased due to the impacts of cooler summer weather in 2003, partially offset by colder winter weather in the first quarter of 2003.

Resales and other. Energy Delivery's fuel expense decreased as a result of reduced resale transactions.

Prices. Energy Delivery's purchased power increased for electric due to an increase in the weighted average on-peak/off-peak cost of electricity at ComEd, and fuel expense for gas increased due to PECO's higher gas prices.

Volume. Energy Delivery's purchased power and fuel expense increased due to increases, exclusive of the effect of weather, in the number of customers and average usage per customer, primarily large and small commercial and industrial customers at ComEd and PECO.

Decommissioning. ComEd changed its presentation for accounting for decommissioning collections upon the adoption of SFAS No. 143 (see Note 13 of the Notes to Consolidated Financial Statements). Decommissioning collections, which are remitted to Generation, were previously recorded as amortization expense and are recorded as purchased power expense in 2003.

Other. Energy Delivery's purchased power decreased due to additional energy billed in 2002 under the purchased power agreement (PPA) with Generation discussed in other operating revenues above.

Operating and Maintenance Expense. The changes in operating and maintenance expense for 2003 compared to 2002 consisted of the following:

Energy Delivery	Variance
Severance, pension and postretirement benefit costs associated with The Exelon Way	$167
Charge recorded at ComEd in 2003 associated with a regulatory settlement [(a)]	41
Increased storm costs	36
Increased employee fringe benefits primarily due to increased health care costs	23
Decreased payroll expense due to fewer employees	(93)
Decreased costs associated with the initial implementation of automated meter reading services at PECO in 2002	(13)
Other	22
Increase in operating and maintenance expense	$183

(a) For more information regarding the settlement, see Note 4 of the Notes to Consolidated Financial Statements.

Depreciation and Amortization Expense. The reduction in depreciation and amortization expense was primarily due to a change in the accounting for nuclear decommissioning at ComEd, lower amortization of ComEd's recoverable transition costs of $58 million and a $48 million reduction due to changes in ComEd's depreciation rates in 2002, partially offset by increased depreciation of $30 million due to capital additions across Energy Delivery and increased competitive transition charge amortization of $28 million at PECO.

Taxes Other Than Income. The reduction in taxes other than income was primarily due to a reversal of real estate tax accruals recorded by PECO of $58 million during the third quarter of 2003 and a favorable settlement of coal use tax at ComEd of $25 million. See Note 19 of the Notes to Consolidated Financial Statements for further information regarding the reversal of real estate tax accruals recorded by PECO.

Interest Expense. The reduction in interest expense was primarily due to refinancing existing debt at lower rates and the pay down of transitional trust notes.

Energy Delivery Operating Statistics and Revenue Detail

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

Retail Deliveries—(in gigawatthours (GWhs))[a]	2003	2002	Variance	% Change
Bundled deliveries[b]				
Residential	37,564	37,839	(275)	(0.7%)
Small commercial & industrial	28,165	29,971	(1,806)	(6.0%)
Large commercial & industrial	20,660	22,652	(1,992)	(8.8%)
Public authorities & electric railroads	6,022	7,332	(1,310)	(17.9%)
Total bundled deliveries	92,411	97,794	(5,383)	(5.5%)
Unbundled deliveries[c]				
Alternative energy suppliers				
Residential	900	1,971	(1,071)	(54.3%)
Small commercial & industrial	7,461	5,634	1,827	32.4%
Large commercial & industrial	10,689	7,652	3,037	39.7%
Public authorities & electric railroads	1,402	913	489	53.6%
	20,452	16,170	4,282	26.5%
PPO (ComEd only)				
Small commercial & industrial	3,318	3,152	166	5.3%
Large commercial & industrial	4,348	5,131	(783)	(15.3%)
Public authorities & electric railroads	1,925	1,346	579	43.0%
	9,591	9,629	(38)	(0.4%)
Total unbundled deliveries	30,043	25,799	4,244	16.5%
Total retail deliveries	122,454	123,593	(1,139)	(0.9%)

(a) One gigawatthour is the equivalent of one million kilowatthours (kWh).
(b) Bundled service reflects deliveries to customers taking electric service under tariffed rates.
(c) Unbundled service reflects customers electing to receive electric generation service from an alternative energy supplier or ComEd's PPO. See Note 4 of the Notes to Consolidated Financial Statements for further discussion of ComEd's PPO.

Electric Revenue	2003	2002	Variance	% Change
Bundled revenues[a]				
Residential	$ 3,715	$ 3,719	$ (4)	(0.1%)
Small commercial & industrial	2,421	2,601	(180)	(6.9%)
Large commercial & industrial	1,394	1,496	(102)	(6.8%)
Public authorities & electric railroads	396	456	(60)	(13.2%)
Total bundled revenues	7,926	8,272	(346)	(4.2%)
Unbundled revenues[b]				
Alternative energy suppliers				
Residential	65	145	(80)	(55.2%)
Small commercial & industrial	214	159	55	34.6%
Large commercial & industrial	196	170	26	15.3%
Public authorities & electric railroads	33	28	5	17.9%
	508	502	6	1.2%
PPO (ComEd only)				
Small commercial & industrial	225	204	21	10.3%
Large commercial & industrial	240	278	(38)	(13.7%)
Public authorities & electric railroads	103	71	32	45.1%
	568	553	15	2.7%
Total unbundled revenues	1,076	1,055	21	2.0%
Total electric retail revenues	9,002	9,327	(325)	(3.5%)
Wholesale and miscellaneous revenue[c]	555	581	(26)	(4.5%)
Total electric revenue	$ 9,557	$9,908	$ (351)	(3.5%)

(a) 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. See Note 4 of the Notes to Consolidated Financial Statements for a discussion of CTC.
(b) 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.
(c) Wholesale and miscellaneous revenues include transmission revenue, sales to municipalities and other wholesale energy sales.

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

Deliveries to customers in million cubic feet (mmcf)	2003	2002	Variance	% Change
Retail sales	**61,858**	54,782	7,076	12.9%
Transportation	**26,404**	30,763	(4,359)	(14.2%)
Total	**88,262**	85,545	2,717	3.2%

Revenue	2003	2002	Variance	% Change
Retail sales	**$ 609**	$ 490	$ 119	24.3%
Transportation	**18**	19	(1)	(5.3%)
Resales and other	**18**	40	(22)	(55.0%)
Total	**$ 645**	$ 549	$ 96	17.5%

Results of Operations–Generation

Generation	2003	2002	Variance	% Change
Operating revenues	**$ 8,135**	$6,858	$ 1,277	18.6%
Purchased power and fuel expense	**5,120**	4,253	867	20.4%
Operating and maintenance expense[(a)]	**2,890**	1,656	1,234	74.5%
Depreciation and amortization expense	**199**	276	(77)	(27.9%)
Operating income (loss)	**(194)**	509	(703)	(138.1%)
Income (loss) before income taxes and cumulative effect of changes in accounting principles	**(420)**	604	(1,024)	(169.5%)
Income (loss) before cumulative effect of changes in accounting principles	**(241)**	387	(628)	(162.3%)
Net income (loss)	**(133)**	400	(533)	(133.3%)

(a) Includes an impairment charge of $945 million before income taxes related to the long-lived assets of Boston Generating.

Net Income (Loss). The decrease in Generation's net income in 2003 as compared to 2002 was primarily due to an impairment charge of $945 million before income taxes recorded in 2003 related to the long-lived assets of Boston Generating, impairment and other transaction-related charges of $280 million before income taxes recorded in 2003 related to Generation's investment in Sithe, and increased operating and maintenance expenses, partially offset by an increase in operating revenues net of purchased power and fuel expense. Generation also experienced an increase in its effective tax rate.

Cumulative effect of changes in accounting principles recorded in 2003 and 2002 included income of $108 million, net of income taxes, recorded in 2003 related to the of adoption of SFAS No. 143 and income of $13 million, net of income taxes, recorded in 2002 related to the adoption of SFAS No. 142. See Note 1 of the Notes to Consolidated Financial Statements for further discussion of these effects.

Operating Revenues. The changes in Generation's operating revenues for 2003 compared to 2002 consisted of the following:

Generation	Variance
Market sales	$1,270
Trading margins	30
Energy Delivery and Exelon Energy Company	(177)
Other	154
Increase in operating revenues	$ 1,277

Market Sales. Sales volume in the wholesale spot and bilateral markets increased primarily due to the acquisition of Exelon New England in November 2002 and the commencement of commercial operations in 2003 of the Boston Generating facilities, Mystic 8 and 9 and Fore River. In addition, average market prices were $5/MWh higher than 2002.

Trading Margins. Trading activity increased revenue by $1 million in 2003 compared to a reduction in revenue of $29 million in 2002 due to an increase in gas prices in April 2002, which negatively affected Generation's trading positions.

Energy Delivery and Exelon Energy Company. Sales to affiliates decreased primarily due to lower volume sales to ComEd, offset by slightly higher prices. Sales to PECO were lower, primarily due to lower prices, offset slightly by higher volumes. Sales to Exelon Energy Company decreased primarily due to the discontinuance of Exelon Energy Company operations in the PJM region.

Other. Revenues also increased in 2003 as compared to 2002, as a result of a $76 million increase in sales of excess fossil fuel. The increased excess fossil fuel is a result of generating plants in the Texas and New England regions operating at less than projected levels. Also, revenue increased by $62 million due to higher decommissioning revenue received from ComEd in 2003 compared to 2002.

Purchased Power and Fuel Expense. The changes in Generation's purchased power and fuel expense for 2003 compared to 2002 consisted of the following:

Generation	Variance
Exelon New England	$429
Prices	350
Volume	46
Hedging activity	22
Other	20
Increase in purchased power and fuel expense	$867

Exelon New England. Generation acquired Exelon New England in November 2002 and Mystic units 8 and 9 began commercial operations during the second quarter of 2003, and Fore River began commercial operations during the third quarter of 2003.

Prices. The increase reflects higher market prices in 2003.

Volume. Purchased power increased in 2003 due to an increase in purchased power from AmerGen under a June 2003 PPA to purchase 100% of the output of Oyster Creek. Prior to the June 2003 PPA, Generation did not purchase power from Oyster Creek. Fuel expense increased due to increases in fossil fuel generation required to meet the increased market demand for energy and the acquisition of generating plants in Texas in April 2002.

Hedging Activity. Mark-to-market losses on hedging activities were $16 million in 2003 compared to a gain of $6 million in 2002.

Other. Other increases in purchased power and fuel were primarily due to additional nuclear fuel amortization of $16 million in 2003 resulting from under-performing fuel which was completely replaced in May 2003, at the Quad Cities Unit 1, and $10 million due to the writedown of coal inventory in 2003 as a result of a fuel burn analysis.

Operating and Maintenance Expense. The changes in operating and maintenance expense for 2003 compared to 2002 consisted of the following:

Generation	Variance
2003 asset impairment charge related to long-lived assets of Boston Generating	$ 945
Adoption of SFAS No. 143[(a)]	197
Increased costs due to generating asset acquisitions made in 2002	78
Severance, pension and postretirement benefit costs associated with The Exelon Way	60
Increased employee fringe benefits primarily due to increased health care costs	54
Decreased refueling outage costs[(b)]	(49)
2002 executive severance	(19)
Other	(32)
Increase in operating and maintenance expense	$1,234

(a) Due to a reclassification of decommissioning-related expenses upon the adoption of SFAS No. 143.
(b) Includes cost savings of $19 million related to one of Generation's co-owned facilities. Refueling outage days, not including Generation's co-owned facilities, decreased from 202 in 2002 to 157 in 2003.

Depreciation and Amortization. The decrease in depreciation and amortization expense in 2003 as compared to 2002 was primarily attributable to a $130 million reduction in decommissioning expense net of ARC depreciation, as these costs are included in operating and maintenance expense after the adoption of SFAS No. 143 and a $12 million decrease due to life extensions of assets acquired in 2002. The decrease was partially offset by $65 million of additional depreciation expense on capital additions placed in service in 2002, of which $18 million of expense is related to plant acquisitions made after the third quarter of 2002.

Effective Income Tax Rate. The effective income tax rate was 42.6% for 2003 compared to 35.9% for 2002. This increase was primarily attributable to the impairments recorded in 2003 related to the long-lived assets of Boston Generating and Generation's investment in Sithe which resulted in a pre-tax loss. Other adjustments that affected income taxes include a decrease in tax-exempt interest recorded in 2003 and an increase in nuclear decommissioning investment income for 2003.

Generation Operating Statistics

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

Sales (in GWhs)	**2003**	2002	% Change
Energy Delivery and Exelon Energy Company	**117,405**	123,975	(5.3%)
Market sales	**107,267**	83,565	28.4%
Total sales	**224,672**	207,540	8.3%

Supply of Sales (in GWhs)	**2003**	2002	% Change
Nuclear generation[(a)]	**117,502**	115,854	1.4%
Purchases–non-trading portfolio[(b)]	**82,860**	78,710	5.3%
Fossil and hydroelectric generation	**24,310**	12,976	87.3%
Total supply	**224,672**	207,540	8.3%

(a) Excluding AmerGen.
(b) Including purchased power agreements with AmerGen.

Trading volumes of 32,584 GWhs and 69,933 GWhs for 2003 and 2002, respectively, are not included in the table above. The decrease in trading volume is a result of reduced volumetric and VAR trading limits in 2003, which are set by the Risk Management Committee (RMC) and approved by the Exelon Board of Directors.

Generation's average revenue for the years ended December 31, 2003 and 2002 were as follows:

($/MWh)[a]	2003	2002	% Change
Average revenue			
Energy Delivery and Exelon Energy Company	**$34.38**	$33.98	1.2%
Market sales	**35.99**	31.01	16.1%
Total–excluding the trading portfolio	**35.15**	32.78	7.2%

(a) One megawatthour (MWh) is the equivalent of one thousand kWhs.

	2003	2002
Nuclear fleet capacity factor[a]	**93.4%**	92.7%
Nuclear fleet production cost per MWh[a]	**$ 12.53**	$ 13.00
Average purchased power cost for wholesale operations per MWh[b]	**$43.29**	$ 41.85

(a) Including AmerGen and excluding Salem, which is operated by Public Service Enterprise Group Incorporated (PSE&G).
(b) Including PPAs with AmerGen.

Generation's supply mix changed as a result of:

- increased nuclear generation due to a lower number of refueling and unplanned outages during 2003 as compared to 2002,
- increased fossil generation due to the Exelon New England plants acquired in November 2002, including plants under construction which became operational in the second and third quarters of 2003 and account for an increase of 8,426 GWhs, and
- additional purchase power of 3,320 GWhs from the addition of Exelon New England, a new PPA with AmerGen which increased purchased power by 3,049 GWhs in the second quarter of 2003, as well as 11,989 GWhs of other miscellaneous power purchases which more than offset a 14,208 GWh reduction in purchased power from Midwest Generation.

The higher nuclear capacity factor and decreased production costs are primarily due to 56 fewer planned refueling outage days, resulting in a $36 million decrease in refueling outage costs, including a $6 million decrease related to AmerGen, in 2003 as compared to 2002. The years ended December 31, 2003 and 2002 included 30 and 26 unplanned outages, respectively, resulting in a $2 million increase in non-refueling outage costs in 2003 as compared to 2002.

Results of Operations–Enterprises

Enterprises	2003	2002	Variance	% Change
Operating revenues	**$ 1,757**	$2,033	$ (276)	(13.6%)
Purchased power and fuel expense	**834**	658	176	26.7%
Operating and maintenance expense	**1,047**	1,327	(280)	(21.1%)
Operating income (loss)	**(162)**	(14)	(148)	n.m.
Income (loss) before income taxes and cumulative effect of changes in accounting principles	**(216)**	134	(350)	n.m.
Income (loss) before cumulative effect of changes in accounting principles	**(135)**	65	(200)	n.m.
Net income (loss)	**(136)**	(178)	42	(23.6%)

n.m.—not meaningful.

Net Income (Loss). The decrease in Enterprises' net income (loss) before cumulative effect of changes in accounting principles in 2003 was primarily due to a decrease in operating revenues and an increase in purchased power and fuel expense, partially offset by a decrease in operating and maintenance expense. Depreciation and amortization expense decreased $29 million before income taxes from 2002 to 2003 primarily as a result of property, plant and equipment classified as held for sale in 2003 and accelerated asset depreciation in the PJM region in 2002. In 2003, Enterprises recorded impairment charges of investments of $46 million before income taxes due to other-than-temporary declines in value and an impairment charge of $8 million before income taxes for its equity method investment in a district cooling business joint venture, partially offset by 2002 charges for impairment of investments of $41 million before income taxes and a net impairment of other assets of $4 million before income taxes. In 2002, Enterprises recorded a pre-tax gain of $198 million on the sale of its investment in AT&T Wireless. The adoption of SFAS No. 143 reduced 2003 net income by $1 million, net of income taxes. The adoption of SFAS No. 142 reduced 2002 net income by $243 million, net of income taxes. See Note 1 of the Notes to Consolidated Financial Statements for further discussion of the adoptions of SFAS No. 143 and SFAS No. 142.

Operating Revenues. The changes in Enterprises' operating revenues for 2003 compared to 2002 consisted of the following:

Enterprises	Variance
InfraSource	$(359)
Exelon Services	(60)
Exelon Energy Company	137
Other	6
Decrease in operating revenues	$(276)

InfraSource. Operating revenues decreased $256 million at InfraSource due to the sale of the majority of the InfraSource businesses in the third quarter of 2003. For the remaining InfraSource businesses, operating revenues decreased $103 million as a result of the closing of certain businesses and the reduction of new business as a result of wind-down efforts and margin deterioration for these businesses.

Exelon Services. Operating revenues decreased $79 million at Exelon Services due to poor economic conditions in the construction market. This decrease was partially offset by improved performance contracting activities of $19 million.

Exelon Energy Company. Operating revenues increased $97 million at Exelon Energy Company due to higher gas prices in 2003. In addition, customer growth in the gas and electric markets increased operating revenues by $69 million and $40 million, respectively. These increases were partially offset by the discontinuance of retail sales in the PJM region of $40 million and the wind-down of the Northeast operations of $29 million.

Purchased Power and Fuel Expense. Purchased power and fuel expense increased primarily due to increased fuel costs at Exelon Energy Company due to higher gas prices and increased customer volume. Higher gas prices accounted for $92 million of the overall increase and increases in customer growth in the gas and electric markets accounted for $67 million and $35 million, respectively. In addition, purchased power and fuel expense increased $31 million from the impact of mark-to-market accounting. These increases were partially offset by reduced costs from the discontinuance of retail sales in the PJM region of $46 million and the wind-down of the Northeast operations of $8 million.

Operating and Maintenance Expense. The changes in Enterprises' operating and maintenance expense for 2003 compared to 2002 consisted of the following:

Enterprises	Variance
InfraSource	$ (267)
Exelon Energy Company	(10)
Exelon Services	(6)
Other	3
Decrease in operating and maintenance expense	$(280)

InfraSource. Operating and maintenance expense decreased $222 million at InfraSource primarily due to the sale of the majority of the InfraSource businesses in the third quarter of 2003. For the remaining InfraSource businesses, operating and maintenance expense decreased $80 million as a result of wind-down efforts for these businesses. These decreases were partially offset by increased expense of $30 million due to margin deterioration on various construction projects.

During 2003, Enterprises recorded a net charge to operating and maintenance expense of $4 million (before income taxes and minority interest) associated with the sale of the majority of the InfraSource businesses. Pursuant to the sales agreement, certain working capital adjustments to the purchase price will be made in 2004.

Exelon Energy Company. Operating and maintenance expense decreased at Exelon Energy Company primarily due to lower general and administrative costs from the discontinuance of retail sales in the PJM region and the wind-down of Northeast operations of $9 million.

Exelon Services. Operating and maintenance expense decreased $56 million at Exelon Services due primarily to delays on mechanical construction projects resulting from poor economic conditions in the construction market. This decrease was partially offset by additional costs from increased performance contracting activities of $13 million, a goodwill impairment charge of $24 million and other asset impairments of $15 million.

Effective Income Tax Rate. The effective income tax rate was 37.5% for 2003 compared to 50.4% for 2002. This decrease 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 during 2002.

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

Exelon Corporation	2002	2001	Variance	% Change
Operating revenues	$14,955	$14,918	$ 37	0.2%
Purchased power and fuel expense	5,262	5,090	172	3.4%
Operating and maintenance expense	4,345	4,394	(49)	(1.1%)
Operating income	3,299	3,362	(63)	(1.9%)
Other income and deductions	(631)	(1,015)	384	(37.8%)
Income before income taxes and cumulative effect of changes in accounting principles	2,668	2,347	321	13.7%
Income before cumulative effect of changes in accounting principles	1,670	1,416	254	17.9%
Net income	1,440	1,428	12	0.8%
Diluted earnings per share	4.44	4.43	0.01	0.2%

Net Income. Net income for 2002 reflects a $230 million after-tax charge for the cumulative effect of changes in accounting principles as a result of the adoption of SFAS No. 142, while net income for 2001 reflects $12 million of after-tax 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 1 of the Notes to Consolidated Financial Statements for further information regarding the adoptions of SFAS No. 142 and SFAS No. 133.

Operating Revenues. Operating revenues were comparable from 2001 to 2002. Energy Delivery experienced an increase of $286 million primarily due to increases in weather normalized volumes and positive weather impacts which was partially offset by a $259 million decrease at Enterprises primarily due to the discontinuance of retail sales in the PJM region at Exelon Energy Company and lower construction revenues at Exelon Services. See further discussion of operating revenues by segment below.

Purchased Power and Fuel Expense. Purchased power and fuel expense increased in 2002 compared to 2001 primarily due to an increase in purchased power associated with increased power supplied by Generation. Total GWhs supplied by Generation, exclusive of trading activity, was 207,540 GWhs in 2002 compared to 196,126 GWhs in 2001. The average supply cost per MWh supplied by Generation was consistent from 2001 to 2002. See further discussion of purchased power and fuel expense by segment below.

Operating and Maintenance Expense. Operating and maintenance expense was consistent from 2001 to 2002. An increase in operating and maintenance expense at Generation of $128 million primarily due to increased refueling outages and generating asset acquisitions in April and November 2002 was partially offset by reduced operating maintenance expenses at Energy Delivery and Enterprises. See further discussion of operating and maintenance expenses by segment below.

Operating Income. Operating income decreased in 2002 as compared to 2001 primarily due to the increase in purchased power and fuel expense discussed above, partially offset by a decrease in depreciation and amortization expense primarily due to the cessation of goodwill amortization.

Other Income and Deductions. Other income and deductions changed primarily due a gain on the sale of Enterprises' investment in AT&T Wireless of $198 million recorded in 2002, an increase in income on Generation's nuclear decommissioning trust funds and a reduction in interest expense at Energy Delivery due to less debt outstanding and the refinancing of existing debt at lower rates.

Results of Operations by Business Segment

The comparisons of 2002 and 2001 operating results and other statistical information set forth below 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	2002	2001	Variance	% Change
Operating revenues	$10,457	$10,171	$286	2.8%
Purchased power and fuel expense	4,602	4,472	130	2.9%
Operating and maintenance expense	1,486	1,568	(82)	(5.2%)
Depreciation and amortization expense	978	1,081	(103)	(9.5%)
Taxes other than income	531	457	74	16.2%
Operating income	2,860	2,593	267	10.3%
Interest expense	854	973	(119)	(12.2%)
Income before income taxes	2,033	1,725	308	17.9%
Net income	1,268	1,022	246	24.1%

Net Income. The increase in Energy Delivery's net income was primarily due to an increase in operating revenues net of purchased power and fuel expense and decreases in operating and maintenance, depreciation and amortization and interest expenses, partially offset by increased taxes other than income, lower interest income on its note receivable from Unicom Investments, Inc., an Exelon subsidiary.

Operating Revenues. The changes in Energy Delivery's operating revenues for 2002 compared to 2001 consisted of the following:

Energy Delivery	Electric	Gas	Total Variance
Volume	$224	$ 15	$239
Weather	151	2	153
Customer choice	95	–	95
Rate changes	(54)	(108)	(162)
Resales and other	–	(15)	(15)
Other effects	(25)	1	(24)
Increase (decrease) in operating revenues	$391	$(105)	$286

Volume. Energy Delivery's electric revenues increased as a result of increases, exclusive of weather impacts, in the number of customers and additional average usage per customer, primarily in the residential customer class.

Exclusive of weather impacts, higher delivery volume increased gas revenue. Total deliveries to customers increased 5% in 2002 compared to 2001, primarily as a result of customer growth and higher transportation volumes.

Weather. Energy Delivery's electric revenues experienced favorable weather impacts, primarily as a result of warmer than usual summer weather. Cooling degree-days in the ComEd and PECO service territories were 29% higher and 15% higher in 2002 as compared to 2001, respectively. Heating degree-days in the ComEd and PECO service territories were 3% higher and 1% higher, respectively, in 2002 compared to 2001.

Customer Choice. Energy Delivery's electric revenues increased from 2001 to 2002 as a result of customer choice activity. The increase includes increased revenues of $226 million from customers in Pennsylvania who selected or returned to PECO as their energy supplier. The increase was partially offset by a decrease in revenues of $131 million from ComEd's customers electing to purchase energy from alternative energy suppliers or electing ComEd's PPO.

Rate Changes. The decrease in electric revenues attributable to rate changes reflect $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 effective January 1, 2002 and the expiration of a 6% reduction in PECO's rates during the first quarter of 2001. The decrease in gas revenues was primarily attributable to a decrease in rates through the purchased gas adjustment clause that became effective in December 2001. The average rate per mmcf in 2002 was 22% lower than the rate in 2001.

Resales and Other. Energy Delivery's gas revenues decreased as a result of a decrease in off-system sales, exchanges and capacity releases.

Other Effects. The reduction in revenue from other effects is primarily a result of a $38 million decrease in off-system sales due to an expiration of wholesale contracts that were offered by ComEd from June 2000 to May 2001 to support the open access program in Illinois and a $15 million reversal for revenue refunds in 2001 related to certain of ComEd's municipal customers as a result of a favorable FERC ruling, partially offset by a reimbursement from Generation of $12 million at ComEd and an $11 million settlement of CTCs by a large PECO customer in the first quarter of 2001.

Purchased Power and Fuel Expense. The changes in Energy Delivery's purchased power and fuel expense for 2002 compared to 2001 consisted of the following:

Energy Delivery	Electric	Gas	Variance
Weather	$ 69	$ –	$ 69
Customer choice	65	–	65
Volume	54	–	54
PJM ancillary charges	41	–	41
Prices	18	(108)	(90)
Other	(15)	6	(9)
Increase (decrease) in purchased power and fuel expense	$232	$(102)	$ 130

Weather. Energy Delivery's purchased power and fuel expense increased in 2002 compared to 2001 due to the impacts of warmer than usual summer weather.

Customer Choice. Customer choice activity resulted in an increase of purchased power and fuel expense, including $210 million due to customers selecting or returning to PECO as their electric supplier, partially offset by $145 million due to ComEd's customers electing to purchase energy from alternative energy suppliers or electing ComEd's PPO.

Volume. Energy Delivery's purchased power and fuel expense increased due to increases, exclusive of weather impacts, in the number of customers and additional average usage per customer, primarily in the residential customer class.

Prices. Fuel expense for gas decreased due to PECO's higher gas prices, which was partially offset by increases in the weighted average on-peak/off-peak cost of electricity at ComEd.

Operating and Maintenance Expense. The changes in operating and maintenance expense for 2002 compared to 2001 consisted of the following:

Energy Delivery	Variance
Decreased employee fringe benefits primarily due to fewer employees	$(39)
Decreased payroll expense due to fewer employees	(32)
Reduced costs due to cost management initiatives	(16)
Change in bad debt reserve estimate	(14)
Decreased storm costs	(12)
Increased costs for manufactured gas plant investigation and remediation	16
Increased costs associated with the initial implementation of automated meter reading services at PECO in 2002	12
Other	3
Decrease in operating and maintenance expense	$(82)

Depreciation and Amortization Expense. The reduction in depreciation and amortization expense was primarily due to the cessation of goodwill amortization at ComEd and a $48 million decrease due to changes in ComEd's depreciation rates in 2002. During 2001, $126 million of goodwill was amortized at ComEd. These decreases were partially offset by $34 million of increased depreciation due to capital additions across Energy Delivery and increased competitive transition charge amortization of $37 million at PECO.

Taxes Other Than Income. The increase in taxes other than income was primarily due to $72 million of additional gross receipts tax at PECO related to additional revenues and an increase in the gross receipts tax rate on electric revenue effective January 1, 2002.

Interest Expense. The reduction in interest expense was primarily due to refinancing existing debt at lower rates and the pay down of ComEd's and PECO's Transitional Trust Notes.

Effective Income Tax Rate. Energy Delivery's effective income tax rate was 37.6% for 2002, compared to 40.8% for 2001. The 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 were as follows:

Retail Deliveries—(in gigawatthours (GWhs))[a]	2002	2001	Variance	% Change
Bundled deliveries[b]				
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[c]				
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%

(a) One gigawatthour is the equivalent of one million kilowatthours (kWh).
(b) Bundled service reflects deliveries to customers taking electric service under tariffed rates.
(c) Unbundled service reflects customers electing to receive electric generation service from an alternative energy supplier or ComEd's PPO. See Note 4 of the Notes to Consolidated Financial Statements for further discussion of ComEd's PPO.

Electric Revenue	2002	2001	Variance	% Change
Bundled revenues[a]				
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[b]				
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[c]	581	594	(13)	(2.2%)
Total electric revenue	$9,908	$ 9,517	$ 391	4.1%

(a) 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. See Note 4 of the Notes to Consolidated Financial Statements for a discussion of CTC.
(b) 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.
(c) Wholesale and miscellaneous revenues include transmission revenue, sales to municipalities and other wholesale energy sales.
n.m.—not meaningful

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

Deliveries to customers in mmcf	2002	2001	Variance	% Change
Retail sales	54,782	54,075	707	1.3%
Transportation	30,763	27,453	3,310	12.1%
Total	85,545	81,528	4,017	4.9%

Revenue	2002	2001	Variance	% Change
Retail sales	$ 490	$ 581	$ (91)	(15.7%)
Transportation	19	18	1	5.6%
Resale and other	40	55	(15)	(27.3%)
Total	$ 549	$ 654	$ (105)	(16.1%)

Results of Operations–Generation

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%
Purchased power and fuel expense	4,253	3,995	258	6.5%
Operating and maintenance expense	1,656	1,528	128	8.4%
Depreciation and amortization expense	276	282	(6)	(2.1%)
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%)

Net Income. The decrease in Generation's net income was primarily due to a decrease in operating revenues net of purchased power and fuel expense and an increase in operating and maintenance expense, partially offset by an increase in income on its nuclear decommissioning trust fund investments.

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. 142, and income of $12 million, net of income taxes, recorded in 2001 related to the adoption of SFAS No. 133. See Note 1 of the Notes to Consolidated Financial Statements for further discussion of these effects.

Operating Revenues. The changes in Generation's operating revenues for 2002 compared to 2001 consisted of the following:

Generation	Variance
Energy Delivery and Exelon Energy Company	$ 124
Market sales	(85)
Trading margins	(36)
Other	29
Increase in operating revenues	$ 32

Energy Delivery and Exelon Energy Company. Sales to affiliates increased primarily due to higher prices. In addition, the increase was a result of higher volume sales to ComEd, offset by lower volume sales to PECO and Exelon Energy Company.

Market Sales. Revenue from market sales decreased primarily due to a $6/MWh decrease in average market prices in 2002 compared to 2001. The decrease was partially offset by an increase in market sales volume.

Trading Margins. Trading margins decreased $36 million, reflecting a $29 million loss for the year ended December 31, 2002 compared to a $7 million gain in the same period in 2001. The increase is primarily related to an increase in gas prices in April 2002, which negatively affected Generation's trading positions.

Other. Revenues also increased $29 million in 2002 compared to the same period in 2001, primarily as a result of increased gas sales resulting from the Texas asset acquisition in April 2002.

Purchased Power and Fuel Expense. Purchased power and fuel expense increased $258 million, or 6% in 2002. The increase is primarily due to increased purchased power and fossil fuel volume. The increase in purchased power and fuel was partially offset by a decrease in the average purchased cost attributed to lower wholesale market prices and reduced transmission costs.

Operating and Maintenance Expense. The changes in operating and maintenance expense for 2002 compared to 2001 consisted of the following:

Generation	Variance
Increased refueling outage costs[(a)]	$ 80
Increased costs due to asset acquisitions made in 2002	21
2002 executive severance	19
Decreased payroll expense due to fewer number of employees	(8)
Other	16
Increase in operating and maintenance expense	$128

(a) Refueling outage days, not including co-owned facilities, increased from 95 in 2001 to 202 in 2002.

Depreciation and Amortization. The decrease in depreciation and amortization expense in 2002 as compared to 2001 was due to a $42 million reduction in depreciation expense arising from the extension of the useful lives on certain generation facilities in 2001, partially offset by $32 million of additional depreciation expense on capital additions placed in service, including the Southeast Chicago Energy Project in July 2002, and two generating plants acquired in April 2002.

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

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 and Exelon Energy Company	123,975	123,793	0.1%
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[(a)]	115,854	116,839	(0.8%)
Purchases—non-trading portfolio[(b)]	78,710	67,942	15.8%
Fossil and hydroelectric generation	12,976	11,345	14.4%
Total supply	207,540	196,126	5.8%

(a) Excluding AmerGen.
(b) Including purchased power agreements with AmerGen.

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

Generation's average revenue per MWh sold for 2002 and 2001 were as follows:

($/MWh)	2002	2001	% Change
Average revenue			
Energy Delivery and Exelon Energy Company	$33.98	$ 33.05	2.8%
Market sales	31.01	37.00	(16.2%)
Total—excluding the trading portfolio	32.78	34.51	(5.0%)

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

Generation's GWh deliveries increased 6% in 2002 primarily due to favorable weather conditions, which increased demand for Energy Delivery and increased market sales attributable to the availability of increased supply from acquired generation and power uprates at existing facilities, slightly offset by a decrease in sales to Exelon Energy Company, 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 hydroelectric net generation due to 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 accounted for an increase of 2,500 GWhs, and strong waterflows which increased the hydroelectric 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 Company, affected by lower actual volumes to those customers, and
- lower market prices.

	2002	2001
Nuclear fleet capacity factor[(a)]	92.7%	94.4%
Nuclear fleet production cost per MWh[(a)]	$13.00	$12.78
Average purchased power cost for wholesale operations per MWh[(b)]	$41.85	$45.94

(a) Including AmerGen and excluding Salem, which is operated by PSE&G.
(b) Including PPAs with AmerGen.

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	2002	2001	Variance	% Change
Operating revenues	$2,033	$2,292	$(259)	(11.3%)
Purchased power and fuel expense	658	854	(196)	(23.0%)
Operating and maintenance expense	1,327	1,436	(109)	(7.6%)
Operating income (loss)	(14)	(77)	63	(81.8%)
Income (loss) before income taxes and cumulative effect of change in accounting principle	134	(128)	262	n.m.
Income (loss) before cumulative effect of change in accounting principles	65	(85)	150	(176.5%)
Net income (loss)	(178)	(85)	(93)	109.4%

n.m. —not meaningful

Net Income (Loss). The increase in Enterprises' income (loss) before cumulative effect of change in accounting principles was primarily due to a pre-tax gain of $198 million recorded in 2002 on the sale of its investment in AT&T Wireless and decreases in purchased power and fuel expense and operating and maintenance expense, partially offset by a decrease in operating revenues. Depreciation and amortization expense decreased $14 million from 2001 to 2002 primarily as a result of the discontinuance of goodwill amortization upon the adoption of SFAS No. 142 on January 1, 2002, partially offset by 2002 accelerated depreciation in the PJM region. In 2002, Enterprises recorded impairment charges of investments of $41 million before income taxes due to other-than-temporary declines in value and a net impairment of other assets of $4 million, as compared to 2001 charges for investment impairments of $13 million and a net impairment of other assets of $2 million before income taxes. In 2002, Enterprises had higher equity in earnings of unconsolidated affiliates of $16 million resulting from the discontinuance of losses on its investment in AT&T Wireless as a result of its sale and $9 million resulting from the recovery of trade receivables previously considered uncollectible from a communications joint venture. The adoption of SFAS No. 142 reduced 2002 net income by $243 million, net of income taxes. See Note 1 of the Notes to Consolidated Financial Statements for further discussion of the adoption of SFAS No. 142.

Operating Revenues. The changes in Enterprises' operating revenues for 2002 compared to 2001 consisted of the following:

Enterprises	Variance
Exelon Energy Company	$ (172)
Exelon Services	(65)
InfraSource	(20)
Other	(2)
Decrease in operating revenues	$(259)

Exelon Energy Company. Operating revenues decreased $168 million at Exelon Energy Company due to the discontinuance of retail sales in the PJM region and lower gas prices of $112 million in 2002. These decreases were partially offset by higher electric sales of $74 million and increased customer growth in the gas market of $33 million.

Exelon Services. Operating revenues decreased primarily as a result of reduced construction projects.

InfraSource. Operating revenues decreased $117 million at InfraSource as a result of the continued decline in the telecommunications industry, partially offset by higher infrastructure and construction services of $97 million from an increase in the electric line of business.

Purchased Power and Fuel Expense. Purchased power and fuel expense at Exelon Energy Company decreased due to reduced costs from the discontinuance of retail sales in the PJM region of $174 million, decreased fuel costs due to lower gas prices of $115 million and $16 million from favorable impacts of mark-to-market accounting relating to Northeast operations. These decreases were partially offset by increased electric costs of $72 million and increased gas costs from customer growth of $32 million.

Operating and Maintenance Expense. The changes in Enterprises' operating and maintenance expense for 2002 compared to 2001 consisted of the following:

Enterprises	Variance
Exelon Services	$ (57)
InfraSource	(43)
Exelon Energy Company	(11)
Other	2
Decrease in operating and maintenance expense	$(109)

Exelon Services. Operating and maintenance expense decreased $51 million at Exelon Services due to lower construction costs and $2 million from general and administrative cost reduction initiatives.

InfraSource. Operating and maintenance expense decreased at InfraSource primarily due to lower construction costs as a result of the decline of the telecommunications industry of $80 million and $16 million from general and administrative cost reduction initiatives, partially offset by higher infrastructure and construction costs of $53 million.

Exelon Energy Company. Operating and maintenance expense decreased at Exelon Energy Company primarily due to lower general and administrative costs from the discontinuance of retail sales in the PJM region.

Effective Income Tax Rate. 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.

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 and Generation's operations. Our working capital deficit is expected to be cured with our anticipated continuance of positive operating cash flows and the eventual elimination of our Boston Generating debt balance upon the transfer of our ownership of Boston Generating. We anticipate that the transfer of Boston Generating will be accomplished on a non-cash basis. 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 $1.5 billion through revolving credit facilities that we currently utilize to support our commercial paper programs. See the Credit Issues section of Liquidity and Capital Resources for further discussion. We primarily use our capital resources to fund capital requirements, including construction, to invest in new and existing ventures, to repay maturing debt, to pay common stock dividends and to fund our pension obligations. Future acquisitions that we may undertake may require external financing, which might include issuing our common stock.

We are in the process of implementing its new business model referred to as The Exelon Way. This business model is focused on improving operating cash flows while meeting service and financial commitments through integration of operations and consolidation of support functions. We have targeted approximately $300 million of annual cash savings beginning in 2004 and increasing the annual cash savings to $600 million in 2006.

As part of the implementation of The Exelon Way, we identified approximately 1,500 positions for elimination by the end of 2004 and recorded a charge for salary continuance severance of $130 million before income taxes during 2003, which we anticipate that the majority will be paid in 2004 and 2005. We are considering whether there are additional positions to be eliminated in 2005 and 2006. We may incur further severance costs associated with The Exelon Way if additional positions are identified to be eliminated. These costs will be recorded in the period in which the costs can be reasonably estimated.

Cash Flows from Operating Activities

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 at fixed prices and are weighted toward the third quarter. Energy Delivery's future cash flows will depend upon the ability to achieve cost savings in operations and the impact of the economy, weather, customer choice and future regulatory proceedings 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 costs.

Cash flows from operations have been and are expected to continue to provide a reliable, steady source of cash flow, sufficient to meet operating and capital expenditures requirements for the foreseeable future. Operating cash flows after 2006 could be negatively affected by changes in the rate regulatory environments of ComEd and PECO, although any effects are not expected to hinder our ability to fund our business requirements. See Business Outlook and the Challenges in Managing our Business for further information regarding the regulatory transition periods.

Cash flows provided by operations in 2003 and 2002 were $3.4 billion and $3.6 billion, respectively. Changes in our cash flows provided by operations are generally consistent with changes in our results of operations, and further adjusted by changes in working capital in the normal course of business.

In addition to the items mentioned in Results of Operations, the following items affected our operating cash flows in 2003 and 2002:

– Purchases of natural gas at higher prices as well as slightly increased volumes during 2003 resulted in an increase in natural gas inventories of $54 million at Generation and PECO and an increase in deferred natural gas costs of $50 million at PECO, resulting in a reduction to operating cash flows of $104 million. During 2002, changes in deferred natural gas costs of $25 million and a decrease in natural gas inventories during the year of $37 million, resulted in a $62 million increase in operating cash flows.
– Discretionary tax-deductible pension plan payments of $367 million in 2003 compared to $202 million in 2002. Additionally, we contributed $134 million and $73 million to the postretirement welfare benefit plans in 2003 and 2002, respectively.

We expect to contribute up to approximately $419 million to our pension plans in 2004. These contributions exclude benefit payments expected to be made directly from corporate assets. Of the $419 million expected to be contributed to the pension plans during 2004, $17 million is estimated to be needed to satisfy IRS minimum funding requirements.

Cash Flows from Investing Activities

Cash flows used in investing activities in 2003 and 2002 were $2.1 billion and $2.6 billion, respectively. Cash used in investing activities decreased from 2002 due to lower capital expenditures of $288 million, net of liquidated damages received during 2003 of $92 million, a reduction in cash used to acquire businesses of $173 million, a net increase over 2002 in amounts contributed into the nuclear decommissioning trust funds of $11 million and a decrease from 2002 in the proceeds from the sale of businesses in the current year of $24 million.

Capital expenditures by business segment for 2003 and projected amounts for 2004 are as follows:

	2003	2004
Energy Delivery	**$ 962**	$ 855
Generation	**953**	972
Enterprises	**14**	1
Corporate and other	**25**	35
Total capital expenditures	**1,954**	1,863
Acquisition of businesses, net of cash acquired	**272**	–
Total capital expenditures and acquisition of businesses	**$2,226**	$1,863

Internally generated cash flow in 2004 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.

Investing activities in 2003 exclude the non-cash issuance of a $238 million note payable for the November 2003 investment in two synthetic fuel-producing facilities. Exelon expects this investment to provide more than $200 million of net cash benefits from 2003 through 2008, with peak net cash of approximately $80 million in 2007. The cash flow impact in 2003 was not material.

Energy Delivery

Energy Delivery's estimated capital expenditures for 2004 reflect the continuation of efforts to improve the reliability of its transmission and distribution systems and capital additions to support new business and customer growth. Approximately 47% of the budgeted 2004 expenditures is for growth and the remainder is for additions to or upgrades of existing facilities. We anticipate that Energy Delivery's capital expenditures will be funded by internally generated funds, borrowings, and the issuance of debt or preferred securities or capital contributions made by us.

Generation

On November 25, 2003, Generation, Reservoir, and Sithe completed a series of transactions resulting in Generation and Reservoir each indirectly owning a 50% interest in Sithe. See Contractual Obligations and Off-Balance Sheet Arrangements—Variable-Interest Entities below for further information regarding this transaction. In December 2003, Generation purchased the 50% interest in AmerGen held by British Energy plc for $240 million, net of cash acquired of $36 million. The acquisition was funded with cash provided by operations.

In April 2002, Generation purchased two natural-gas and oil-fired generating plants from TXU for $443 million. The purchase was funded with commercial paper, which Exelon issued and Generation repaid with cash flows from operations. Investing activities in 2002 also include the November 1, 2002 purchase of Exelon New England, which resulted in a use of cash of $2 million, net of $12 million of cash acquired. The remainder of the purchase was financed with a $534 million note payable to Sithe, which was subsequently increased to $536 million. At December 31, 2003, Generation has repaid $446 million of the note payable to Sithe, leaving a balance of $90 million, which is payable on the earlier of December 1, 2004, certain liquidity needs, or a change of control.

Generation's capital expenditures for 2003 reflected the construction of three Boston Generating facilities with capacity of 2,288 MWs of energy, additions to and upgrades of existing facilities (including nuclear refueling outages), and nuclear fuel. During 2003, Boston Generating received $92 million of liquidated damages from Raytheon Company (Raytheon) as a result of Raytheon not meeting the expected completion date and certain contractual performance criteria in connection with Raytheon's construction of Boston Generating's Mystic 8 and 9 and Fore River generating facilities. We project that Generation's capital expenditures in 2004 will be higher than they were in 2003, 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. Generation is planning on ten nuclear refueling outages in 2004, compared to eight during 2003. However, we project that the total capital expenditures for nuclear refueling outages will decrease in 2004 from 2003 by $18 million. We anticipate that Generation's capital expenditures will be funded by internally generated funds, Generation's borrowings or capital contributions from us.

Enterprises

In September 2003, Enterprises sold the electric construction and services, underground and telecom businesses of InfraSource for cash of $175 million, net of transaction costs and cash transferred to the buyer upon sale. In April 2002, Enterprises sold its 49% interest in AT&T Wireless for $285 million in cash.

Enterprises' capital expenditures were $14 million in 2003. Enterprises' capital expenditures for 2003 were primarily for additions to or upgrades of existing facilities. We project that Enterprises' capital expenditures for 2004 will be approximately $1 million.

Cash Flows from Financing Activities

Cash flows used in financing activities for the years ended December 31, 2003 and 2002 were $1.2 billion and $1.1 billion, respectively. See Note 11—Long-Term Debt of the Notes to Consolidated Financial Statements for further information regarding the 2003 debt issuances and retirements. See Note 24—Subsequent Events of the Notes to Consolidated Financial Statements for further information regarding 2004 redemptions of debt.

The 2003 cash dividend payments on common stock were $620 million as compared to $563 million in 2002. On January 28, 2003, the Exelon Board of Directors increased the quarterly dividend on Exelon's common stock to $0.46 per share. On July 29, 2003, the Exelon Board of Directors increased the quarterly dividend to $0.50 per share. On January 27, 2004, the Exelon Board of Directors approved a 10% increase in the quarterly dividend rate to $0.55 per share and approved a 2-for-1 stock split contingent upon receipt of all required regulatory approvals. Payment of future dividends is subject to approval and declaration by the Board.

Financing activities exclude the non-cash issuance of a $534 million note to Sithe for the November 1, 2002 acquisition of Exelon New England, which was subsequently increased to $536 million.

Credit Issues

Exelon Credit Facility

Exelon meets its short-term liquidity requirements primarily through the issuance of commercial paper by Exelon corporate holding company (Exelon Corporate) and by ComEd, PECO and Generation. In October 2003, Exelon, ComEd, PECO and Generation replaced their $1.5 billion bank unsecured revolving credit facility with a $750 million 364-day unsecured revolving credit agreement and a $750 million three-year unsecured revolving credit agreement with a group of banks. Both revolving credit agreements are used principally to support the commercial paper programs at Exelon, ComEd, PECO and Generation and to issue letters of credit. The 364-day agreement includes a term-out option provision that allows a borrower to extend the maturity of revolving credit borrowings outstanding at the end of the 364-day period for one year.

At December 31, 2003, aggregate sublimits under the credit agreements were $1.0 billion, $100 million, $150 million and $250 million for Exelon Corporate, ComEd, PECO, and Generation, respectively. Sublimits under the credit agreements can change upon written notification to the bank group. Exelon Corporate, ComEd, PECO and Generation had approximately $955 million, $80 million, $148 million and $170 million of unused bank commitments under the credit agreements, respectively, at December 31, 2003. At December 31, 2003, commercial paper outstanding was $280 million and $46 million at Exelon Corporate and PECO, respectively. ComEd and Generation did not have any commercial paper outstanding at December 31, 2003. Interest rates on the advances under the credit facility are based on either the London Interbank Offering Rate (LIBOR) or prime plus an adder based on the credit rating of the borrower as well as the total outstanding amounts under the agreement at the time of borrowing. The maximum adder would be 175 basis points.

The credit agreements require Exelon Corporate, ComEd, PECO and Generation to maintain a minimum cash from operations to interest expense ratio for the twelve-month period ended on the last day of any quarter. The ratios exclude revenues and interest expenses attributable to securitization debt, certain changes in working capital, distributions on preferred securities of subsidiaries and, in the case of Exelon Corporate and Generation, revenues from Exelon New England and interest on the debt of Exelon New England's project subsidiaries. Exelon Corporate is measured at the Exelon consolidated level. At December 31, 2003, Exelon Corporate, ComEd, PECO and Generation were in compliance with the credit agreement thresholds. The following table summarizes the minimum thresholds reflected in the credit agreement for the twelve-month period ended December 31, 2003:

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

At December 31, 2003, our capital structure consisted of 62% of long-term debt, including long-term debt to financing trusts, 35% common equity, 3% notes payable and less than 1% preferred securities of subsidiaries. Total debt included $6.2 billion owed to unconsolidated affiliates of ComEd and PECO that qualify as special purpose entities under FIN No. 46-R. These special purpose entities were created for the sole purpose of issuing debt obligations to securitize intangible transition property and CTCs of Energy Delivery or mandatorily redeemable preferred securities. See Note 1 of the Notes to Consolidated Financial Statements for further information regarding FIN No. 46-R.

Boston Generating Project Debt

Boston Generating has a $1.25 billion credit facility (Boston Generating Facility), which was entered into primarily to finance the development and construction of the Mystic 8 and 9 and Fore River generating facilities. Approximately $1.0 billion of debt was outstanding under the credit facility at December 31, 2003, all of which was reflected in our Consolidated Balance Sheet as a current liability due to certain events of default described below. The Boston Generating Facility is non-recourse to us and an event of default under the Boston Generating Facility does not constitute an event of default under any other of our debt instruments or the debt instruments of our subsidiaries.

The Boston Generating Facility required that all of the projects achieve "Project Completion," as defined in the Boston Generating Facility (Project Completion) by July 12, 2003. Project Completion was not achieved by July 12, 2003, resulting in an event of default under the Boston Generating Facility. Mystic 8 and 9 and Fore River have begun commercial operation, although they have not yet achieved Project Completion.

We have commenced the process of an orderly transition out of the ownership of Boston Generating and the Mystic 8 and 9 and Fore River generating projects. Our decision to transition out of the projects was made as a result of our evaluation of the projects and discussions with the lenders under the Boston Generating Facility. We anticipate that this transition will occur in 2004.

Generation Revolving Credit Facilities

On September 29, 2003, Generation closed on an $850 million revolving credit facility that replaced a $550 million revolving credit facility that had originally closed on June 13, 2003. Generation used the facility to make the first payment to Sithe relating to the $536 million note that was used to purchase Exelon New England. This note was restructured in June 2003 to provide for a payment of $210 million of the principal on June 16, 2003, payment of $236 million of the principal on the earlier of December 1, 2003 or upon a change of control of Generation, and payment of the remaining principal on the earlier of December 1, 2004, upon reaching certain Sithe liquidity requirements, or upon a change of control of Generation. Generation paid $446 million on the note to Sithe in 2003. Generation terminated the $850 million revolving credit facility on December 22, 2003.

Intercompany Money Pool

To provide an additional short-term borrowing option that will generally be more favorable to the borrowing participants than the cost of external financing, we operate an intercompany money pool. Participation in the money pool is subject to authorization by our corporate treasurer. ComEd and its subsidiary, Commonwealth Edison of Indiana, Inc. (ComEd of Indiana), PECO, Generation and BSC may participate in the money pool as lenders and borrowers, and Exelon Corporate may participate as a lender. Funding of, and borrowings from, the money pool are predicated on whether the contributions and borrowings result in economic benefits. Interest on borrowings is based on short-term market rates of interest, or, if from an external source, specific borrowing rates. During 2003, ComEd and PECO had various contributions to the money pool, and Generation and BSC had various loans from the money pool as described in the attached table:

	Maximum Invested	Maximum Borrowed	December 31, 2003 Contributed (Borrowed)
ComEd	$483	$ –	$ 405
PECO	59	–	–
Generation	–	395	(301)
BSC	–	104	(104)

Security Ratings

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. In the fourth quarter of 2003, Standard & Poor's Ratings Services affirmed our corporate credit ratings but revised its outlook to negative from stable. None of our borrowings is 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 two $750 million credit agreements and certain other credit facilities.

The following table shows our securities ratings at December 31, 2003:

	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
	Transition bonds [(a)]	Aaa	AAA	AAA
PECO	Senior secured debt	A2	A	A
	Commercial paper	P1	A2	F1
	Transition bonds [(b)]	Aaa	AAA	AAA
Generation	Senior unsecured debt	Baa1	A-	BBB+
	Commercial paper	P2	A2	F2

(a) Issued by ComEd Transitional Funding Trust, an unconsolidated affiliate of ComEd.
(b) Issued by PECO Energy Transition Trust, an unconsolidated affiliate of PECO.

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

As part of the normal course of business, we routinely enter into physical or financially settled contracts for the purchase and sale of capacity, energy, fuels and emissions allowances. These contracts either contain express provisions or otherwise permit our counterparties and us to demand adequate assurance of future performance when there are reasonable grounds for doing so. In accordance with the contracts and applicable contracts law, if Exelon or Generation is downgraded by a credit rating agency, especially if such downgrade is to a level below investment grade, it is possible that a counterparty would attempt to rely on such a downgrade as a basis for making a demand for adequate assurance of future performance. Depending on our net position with a counterparty, the demand could be for the posting of collateral. In the absence of expressly agreed to provisions that specify the collateral that must be provided, the obligation to supply the collateral requested will be a function of the facts and circumstances of Exelon or Generation's situation at the time of the demand. If we can reasonably claim that we are willing and financially able to perform our obligations, it may be possible to successfully argue that no collateral should be posted or that only an amount equal to two or three months of future payments should be sufficient.

Shelf Registration

On September 25, 2003, we filed a shelf registration statement, to register the sale by Exelon of $2.0 billion of unsecured senior debt securities; common stock; stock purchase contracts; stock purchase units; preferred stock in one or more series; subordinated debt securities to be purchased by Exelon Capital Trust I, Exelon Capital Trust II and/or Exelon Capital Trust III; and guarantees of trust preferred securities sold by Exelon Capital Trust I, Exelon Capital Trust II, and Exelon Capital Trust III. The registration statement became effective on February 11, 2004. As of the date of this filing, no securities have been issued under this registration statement.

PUHCA Restrictions

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 $4.0 billion. On December 22, 2003, we filed an application (Financing Application) requesting financing authority in an aggregate amount not to exceed $8 billion for the new authorization period, April 1, 2004 through April 15, 2007. The Financing Application is still pending. As of December 31, 2003, there was $2.0 billion of financing authority remaining under the SEC order. The current order limits our short-term debt outstanding to $3.0 billion of the $4.0 billion total financing authority. The Financing Application requests that the short-term debt sub-limit restriction be eliminated. The SEC order also authorized us to issue guarantees of up to $4.5 billion outstanding at any one time. In the Financing Application, we requested an additional $1.5 billion of guaranty authority. At December 31, 2003, Exelon had provided $1.9 billion of guarantees under the SEC order. See Contractual Obligations and Off-Balance Sheet Arrangements 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) of not less than 30%. At December 31, 2003, Exelon's common equity ratio was 35%. Exelon expects that it will maintain a common equity ratio of at least 30%.

Under applicable law, Exelon, ComEd, PECO and Generation can pay dividends only from retained, undistributed or current earnings. Under Illinois law, ComEd may not pay any dividend on its stock unless "its earnings and earned surplus are sufficient to declare and pay same after provision is made for reasonable and proper reserves," or unless it has specific authorization from the ICC. Furthermore, a significant loss recorded at ComEd may limit the dividends that ComEd can distribute to Exelon. At December 31, 2003, Exelon had retained earnings of $2.3 billion, including ComEd's retained earnings of $883 million (of which $709 million had been appropriated for future dividend payments), PECO's retained earnings of $546 million and Generation's undistributed earnings of $602 million. We are also limited by order of the SEC under PUHCA to an aggregate investment of $4.0 billion in exempt wholesale generators (EWGs) and foreign utility companies (FUCOs). At December 31, 2003, we had invested $2.5 billion in EWGs, leaving $1.5 billion of investment authority under the order. In the Financing Application, we requested EWG authority in an aggregate amount not to exceed $7 billion.

Contractual Obligations and Off-Balance Sheet Arrangements

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

		Payment due within			
	Total	2004	2005-2006	2007-2008	Due 2009 and beyond
Long-term debt	$ 9,284	$ 1,385	$ 1,159	$1,207	$ 5,533
Long-term debt to financing trusts	6,070	470	1,629	1,950	2,021
Notes payable to Sithe	90	90	–	–	–
Commercial paper	326	326	–	–	–
Operating leases	744	49	97	86	512
Power purchase obligations	10,475	2,635	1,827	1,410	4,603
Fuel purchase agreements	3,034	476	825	582	1,151
Other purchase obligations	145	31	71	38	5
Chicago agreement(a)	54	6	12	12	24
Regulatory commitments	30	10	20	–	–
Spent nuclear fuel obligation	867	–	–	–	867
Obligation to minority shareholders	51	3	6	6	36
Pension IRS minimum funding requirement	17	17	–	–	–
Decommissioning(b)	2,997	–	–	–	2,997
Total contractual obligations	$34,184	$5,498	$5,646	$ 5,291	$17,749

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

(b) Represents the present value of our obligation to decommission nuclear plants.

For additional information about:

– long-term debt, see Note 11 of the Notes to Consolidated Financial Statements
– notes payable, see Note 10 of the Notes to Consolidated Financial Statements
– operating leases, energy commitments, fuel purchase agreements and other purchase obligations, see Note 19 of the Notes to Consolidated Financial Statements
– regulatory commitments, see Note 4 of the Notes to Consolidated Financial Statements
– the spent nuclear fuel obligation, see Note 13 of the Notes to Consolidated Financial Statements
– the obligation to minority shareholders, see Note 19 of the Notes to Consolidated Financial Statements
– the contribution required to our pension plans to satisfy IRS minimum funding requirements, see Note 14 of the Notes to Consolidated Financial Statements

Two affiliates of Exelon New England have long-term supply agreements through December 2022 with Distrigas of Massachusetts, LLC (Distrigas) for gas supply, primarily for the Boston Generating units. Under the agreements, prices are indexed to New England gas markets. Exelon New England has guaranteed these entities' financial obligations to Distrigas under the Distrigas agreements. It is currently anticipated that Exelon New England's guaranty to Distrigas will continue following the eventual transfer of the ownership interests in Boston Generating. This guaranty is non-recourse to Generation. At December 31, 2003, Exelon New England had net assets of approximately $70 million, exclusive of the Boston Generating net assets.

Exelon has committed to pay down approximately $30 million of the Exelon New England note during the first six months of 2004 to fund Sithe's expected acquisition of the 40% of Sithe/Independence Power Partners, L.P. that it does not currently own.

Generation has an obligation to decommission its nuclear power plants. NRC regulations require that licensees of nuclear generating facilities demonstrate reasonable assurance that funds will be available in certain minimum amounts at the end of the life of the facility to decommission the facility. Based on estimates of decommissioning costs for each of the nuclear facilities in which Generation has an ownership interest, the ICC permits ComEd, and the PUC permits PECO, to collect from their customers and deposit in nuclear decommissioning trust funds maintained by Generation amounts which, together with earnings thereon, will be used to decommission such nuclear facilities. Upon adoption of SFAS No. 143, Generation was required to re-measure its decommissioning liabilities at fair value and recorded an asset retirement obligation of $2.4 billion on January 1, 2003. Increases in the asset retirement obligation are recorded as operating and maintenance expense. At December 31, 2003, the asset retirement obligation recorded within Generation's Consolidated Balance Sheet was $3.0 billion. Decommissioning expenditures are expected to occur primarily after the plants are retired and are currently estimated to begin in 2029 for plants currently in operation. To fund future decommissioning costs, Generation held $4.7 billion of investments in trust funds, including net unrealized gains and losses, at December 31, 2003. See Note 13 of the Notes to Consolidated Financial Statements for further discussion of Generation's decommissioning obligation.

See Note 19 of the Notes to Consolidated Financial Statements for discussion of Exelon's commercial commitments as of December 31, 2003.

IRS Refund Claims

ComEd and PECO have entered into several agreements with a tax consultant related to the filing of refund claims with the Internal Revenue Service (IRS) and have made refundable prepayments of $11 million and $5 million, respectively, for potential fees associated with these agreements. The fees for these agreements are contingent upon a successful outcome and are based upon a percentage of the refunds recovered from the IRS, if any. As such, ultimate net cash flows to Exelon related to these agreements will either be positive or neutral depending upon the outcome of the refund claim with the IRS. These potential tax benefits and associated fees could be material to our financial position, results of operations and cash flows. ComEd's tax benefits for periods prior to the Merger would be recorded as a reduction of goodwill pursuant to a reallocation of the Merger purchase price. We cannot predict the timing of the final resolution of these refund claims.

Variable Interest Entities

Sithe. We are a 50% owner of Sithe and account for the investment as an unconsolidated equity investment. Based on our interpretation of FIN No. 46-R, it is reasonably possible that we will consolidate Sithe as of March 31, 2004. At December 31, 2003, Sithe had total assets of $1.5 billion (including the $90 million note from Generation) and total debt of $1.0 billion. The $1.0 billion of debt includes $588 million of subsidiary debt incurred in prior years primarily to finance the construction of six new generating facilities, $419 million of subordinated debt, $43 million of current portion of long-term debt, but excludes $469 million of non-recourse project debt associated with Sithe's equity investments. For the year ended December 31, 2003, Sithe had revenues of $690 million and incurred a net loss of approximately $72 million. As of December 31, 2003, we had a $47 million investment in Sithe. We contractually do not own any interest in Sithe International, a subsidiary of Sithe. As such, a portion of Sithe's net assets and results of operations would be eliminated from our Consolidated Balance Sheets and Consolidated Statements of Income through a minority interest if Sithe is consolidated under FIN No. 46-R as of March 31, 2004.

On November 25, 2003, Generation, Reservoir and Sithe completed a series of transactions resulting in Generation and Reservoir each indirectly owning a 50% interest in Sithe. This series of transactions is described below. Immediately prior to these transactions, Sithe was owned 49.9% by Generation, 35.2% by Apollo Energy, LLC (Apollo), and 14.9% by subsidiaries of Marubeni Corporation (Marubeni).

On November 25, 2003, entities controlled by Reservoir purchased certain Sithe entities holding six U.S. generating facilities, each a qualifying facility under the Public Utility Regulatory Policies Act, in exchange for $37 million ($21 million in cash and a $16 million two-year note); and entities controlled by Marubeni purchased all of Sithe's entities and facilities outside of North America (other than Sithe Energies Australia (SEA) of which it purchased a 49% interest on November 24, 2003 for separate consideration) for $178 million. Marubeni agreed to acquire the remaining 51 % of SEA in 90 days if a buyer is not found, although discussions regarding an extension are ongoing.

Following the sales of the above entities, Generation transferred its wholly owned subsidiary that held the Sithe investment to a newly formed holding company. The subsidiary holding the Sithe investment acquired the remaining Sithe interests from Apollo and Marubeni for $612 million using proceeds from a $580 million bridge financing and available cash. Generation sold a 50% interest in the newly formed holding company for $76 million to an entity controlled by Reservoir on November 25, 2003. On November 26, 2003, Sithe distributed $580 million of available cash to its parent, which then utilized the distributed funds to repay the bridge financing.

In connection with this transaction, Generation recorded obligations related to $39 million of guarantees in accordance with FIN No. 45 "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness to Others". These guarantees were issued to protect Reservoir from credit exposure of certain counterparties through 2015 and other indemnities. In determining the value of the FIN No. 45 guarantees, we utilized a probabilistic model to assess the possibilities of future payments under the guarantees.

Both Generation and Reservoir's 50% interests in Sithe are subject to put and call options that could result in either party owning 100% of Sithe. While our intent is to fully divest Sithe, the timing of the put and call options vary by acquirer and can extend through March 2006. The pricing of the put and call options is dependent on numerous factors, such as the acquirer, date of acquisition and assets owned by Sithe at the time of exercise. Any closing under either the put or call options is conditioned upon obtaining state and Federal regulatory approvals.

Financing Trusts of ComEd and PECO. During June 2003, PECO issued $103 million of subordinated debentures to PECO Energy Capital Trust IV (PECO Trust IV) in connection with the issuance by PECO Trust IV of $100 million of preferred securities (see Note 16 of the Notes to Consolidated Financial Statements). Effective July 1, 2003, PECO Trust IV was deconsolidated from the financial statements of PECO in conjunction with FIN No. 46. The $103 million of subordinated debentures issued by PECO to PECO Trust IV was recorded as long-term debt to financing trusts within the Consolidated Balance Sheets.

Effective December 31, 2003, ComEd Financing II, ComEd Financing III, ComEd Funding, LLC, ComEd Transitional Funding Trust, PECO Trust III and PECO Energy Transition Trust were deconsolidated from the financial statements of Exelon in conjunction with the adoption of FIN No. 46-R. Amounts of $6.1 billion owed by ComEd and PECO to these financing trusts was recorded as debt to financing trusts within the Consolidated Balance Sheets as of December 31, 2003.

Other. Exelon continues to review entities with which Exelon and its subsidiaries have business arrangements to determine if those entities are variable interest entities under FIN No. 46-R and, if so, whether consolidation of these entities will be required as of March 31, 2004.

PECO Accounts Receivable Agreement

PECO is party to an agreement with a financial institution under which it can sell or finance with limited recourse an undivided interest, adjusted daily, in up to $225 million of designated accounts receivable until November 2005. PECO entered into this agreement to diversify its funding sources at favorable floating interest rates. At December 31, 2003, PECO had sold a $225 million interest in accounts receivable, consisting of a $176 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 $49 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, 2003 and 2002, PECO met this requirement and was not required to make any cash deposit.

Nuclear Insurance Coverage

We carry property damage, decontamination and premature decommissioning insurance for each station loss resulting from damage to our 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 POLICIES AND ESTIMATES

The preparation of financial statements in conformity with GAAP requires that management apply accounting policies and make estimates and assumptions that affect results of operations and the amounts of assets and liabilities reported in the financial statements. Management discusses these policies, estimates and assumptions within its Accounting and Disclosure Governance Committee on a regular basis and provides periodic updates on management decisions to the Audit Committee of the Exelon Board of Directors. Management believes that the following areas require significant management judgment regarding the application of an accounting policy or in making estimates and assumptions to describe matters that are inherently uncertain and that may change in subsequent periods: accounting for derivative instruments, regulatory accounting, nuclear decommissioning, depreciable lives of property, plant and equipment, impairment of assets including goodwill, severance accounting, defined benefit pension and other postretirement welfare benefits, taxation, unbilled energy revenues and environmental costs. Further discussion of the application of these accounting policies can be found in the Notes to Consolidated Financial Statements.

Accounting for Derivative Instruments

We generally account for derivative financial instruments on our balance sheet at their fair value unless they qualify for a normal purchases and normal sales exception or unless specific hedge accounting criteria are met. How such instruments are classified affects how they are reported in our financial statements. If the normal purchases and normal sales exception applies, then gains and losses are recognized when the underlying physical transaction affects earnings. If the derivative qualifies as a cash-flow hedge, changes in the fair value of the derivative are recorded in other comprehensive income in shareholders' equity. If neither applies, then changes in the fair value of the derivative are recognized in our earnings.

The availability of the normal purchases and normal sales exception is based upon our assessment of the ability and intent to deliver or take delivery, which 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 these contracts not qualifying for the normal purchases and normal sales exception.

Identification of an energy contract as a qualifying cash-flow hedge requires us to determine that the contract is in accordance with our Risk Management Policy, the forecasted future transaction is probable, and the hedging relationship between the energy contract and the expected future purchase or sale of energy is expected to be highly effective at the initiation of the hedge and throughout the hedging relationship. Internal models that measure the statistical correlation between the derivative and the associated hedged item determine the effectiveness of such an energy contract designated as a hedge. We reassess these cash-flow hedges on a regular basis to determine if they continue to be effective and that the forecasted future transactions are probable. When 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.

As a part of our accounting for derivatives, 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 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 is a widely accepted valuation methodology.

Regulatory Accounting

We account for our regulated electric and gas operations in accordance with SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation" (SFAS No. 71), which requires us to reflect the effects of rate regulation in our financial statements. Use of SFAS No. 71 is applicable to our utility operations that meet the following criteria: (1) third-party regulation of rates; (2) cost-based rates; and (3) a reasonable assumption that all costs will be recoverable from customers through rates. As of December 31, 2003, we have concluded that the operations of ComEd and PECO meet the criteria. If we conclude in a future period that a separable portion of our business no longer meets the criteria, we are required to eliminate the financial statement effects of regulation for that part of our business, which would include the elimination of any regulatory assets and liabilities that had been recorded within our Consolidated Balance Sheets. The impact of not meeting the criteria of SFAS No. 71 could be material to our financial statements as a one time extraordinary item and through impacts on continuing operations. See Note 4 of the Notes to Consolidated Financial Statements for further information regarding regulatory issues.

Regulatory assets represent costs that have been deferred to future periods when it is probable that the regulator will allow for recovery through rates charged to customers. Regulatory liabilities represent revenues received from customers to fund expected costs that have not yet been incurred. As of December 31, 2003, we had recorded $5.3 billion and $1.9 billion of regulatory assets and regulatory liabilities, respectively, within our Consolidated Balance Sheets. See Note 20 of the Notes to Consolidated Financial Statements for further information regarding our significant regulatory assets and liabilities.

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

The electric businesses of both ComEd and PECO are currently subject to rate freezes or rate caps that limit the opportunity to recover increased costs and the costs of new investment in facilities through rates during the rate freeze or rate cap period. Because 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. If future recovery of costs ceases to be probable, the regulatory 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 and state law.

Nuclear Decommissioning

We account for our obligation to decommission our nuclear generating plants under SFAS No. 143, "Asset Retirement Obligations" (SFAS No. 143), which requires that we make significant estimates of decommissioning costs to be incurred in future periods. We adopted SFAS No. 143 on January 1, 2003 and recorded income of $112 million (net of income taxes) as a cumulative effect of a change in accounting principle. For more information regarding the adoption and ongoing application of SFAS No. 143, see Note 1 and Note 13 of the Notes to Consolidated Financial Statements.

Upon the adoption of SFAS No. 143, we were required to estimate the fair value of our obligation for the future decommissioning of our nuclear generating plants. To estimate the fair value of the decommissioning obligation, we used a probability-weighted, discounted cash flow model with multiple scenarios. Key assumptions used in the determination of fair value included the following:

Decommissioning Cost Studies. We used decommissioning cost studies prepared by a third party to provide 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. Annual cost escalation studies were used to determine escalation factors based on inflation indices for labor, equipment and materials, energy, and low-level radioactive waste disposal costs.

Probabilistic Cash Flow Models. Our probabilistic cash flow models included the assignment of probabilities to various cost levels and various timing scenarios. The probability of various timing scenarios incorporated the factors of current license lives and life extensions and the timing of Department of Energy (DOE) acceptance for disposal of spent nuclear fuel.

Discount Rates. The estimated probability-weighted cash flows using these various scenarios were discounted using credit-adjusted, risk-free rates applicable to the various businesses.

Changes in the assumptions underlying the items discussed above could have materially affected the decommissioning obligation recorded upon the adoption of SFAS No. 143 and could affect future costs related to decommissioning recorded in our consolidated financial statements. Under SFAS No. 143, the fair value of the nuclear decommissioning obligation is adjusted on an ongoing basis as the model input factors change.

Depreciable Lives of Property, Plant and Equipment

We have a significant investment in electric generation assets and electric and natural gas transmission and distribution assets. Depreciation of these assets is generally provided over their estimated service lives on a straight-line basis using the composite method. The estimation of service lives requires management judgment regarding the period of time that the assets will be in use. As circumstances warrant, depreciation estimates are reviewed to determine if any changes are needed. Effective July 1, 2002, ComEd decreased its depreciation rates based on a depreciation study, resulting in an annualized reduction in depreciation expense of $96 million. Effective April 1, 2001 and July 1, 2001, Generation extended the estimated service lives of certain non-AmerGen generating stations primarily based on service life extensions applied for with regulatory agencies, resulting in an annualized reduction in depreciation expense of $132 million. We anticipate extending the depreciable lives of the AmerGen stations beginning in January 2004 concurrent with our initial full month of 100% ownership. Additional changes to depreciation estimates in future periods could have a significant impact on the amount of depreciation charged to the financial statements. Depreciation expense for the year ended December 31, 2003 was $667 million.

Asset Impairments

Long-Lived Assets and Investments. We evaluate the carrying value of our long-lived assets, excluding goodwill, when circumstances indicate the carrying value of those assets may not be recoverable. The review of assets for impairment requires significant assumptions about operating strategies and estimates of future cash flows. A variation in an assumption could result in a different conclusion regarding the realizability of the asset. The potential impact of recognizing an impairment of the assets reported within our Consolidated Balance Sheets, as well as on net income, could be and has been material to our consolidated financial statements.

In 2003, we recorded an impairment charge of $945 million (before income taxes) related to the long-lived assets of Boston Generating, an indirect wholly owned subsidiary of Generation, due to our decision to transition out of our ownership of Boston Generating. See Note 2 of the Notes to Consolidated Financial Statements for further information. In determining the amount of the impairment charge, we compared the carrying value of Boston Generating's long-lived assets to their estimated fair value. The fair value was determined using estimated future discounted cash flows from those assets, which incorporated assumptions relative to the period of time that we will continue to own and operate Boston Generating. The time required to fully transition out of ownership of Boston Generating was uncertain and subject to change at the time the impairment charge was recorded. We utilized a discount rate based upon valuations of the business developed at the purchase date. A change in our assumptions, including estimated cash flows and the discount rate, could have had a significant impact on the amount of the impairment charge recorded.

In 2003, we recorded impairment charges totaling $255 million (before income taxes) associated with a decline in the fair value of Generation's investment in Sithe. In reaching that decision, we considered various factors, including negotiations to sell our investment in Sithe, which indicated an other-than-temporary decline in fair value.

In 2003, we recorded impairment charges related to investments held by Enterprises of approximately $54 million (before income taxes). We had determined that an other-than-temporary decline in the fair value of these investments had occurred and considered various factors in our decision to record an impairment of the investments, including recent third-party valuations of the investments. The other-than-temporary determination was significant because any increase in fair value of these investments will not be recoverable until they are sold. Had we determined that the impairment was temporary, no impairment charge would have been recorded. The valuations of these investments, which formed the basis for the impairment charge, required assumptions regarding the future earnings potential of these investments. Actual results from these investments have fluctuated in the past and are expected to continue.

Goodwill. We have approximately $4.7 billion of goodwill recorded at December 31, 2003, which relates entirely to the ComEd goodwill within the Energy Delivery reporting unit. As described below, we recorded charges of $72 million (before income taxes) during 2003 to fully impair the goodwill that had been recorded within the Exelon Services and InfraSource reporting units of our Enterprises segment. We perform an assessment for impairment of our goodwill at least annually, or more frequently, if events or circumstances indicate that goodwill might be impaired. Application of the goodwill impairment test requires judgment, including the identification of reporting units, assigning assets and liabilities to reporting units, assigning goodwill to reporting units, and determining the fair value of each reporting unit.

Energy Delivery. Our annual assessment of goodwill impairment at the Energy Delivery reporting unit was performed as of November 1, 2003 and this assessment determined that goodwill was not impaired. In our assessment, to estimate the fair value of the Energy Delivery reporting unit, we used a probability-weighted, discounted cash flow model with multiple scenarios. The determination of the fair value is dependent on many sensitive, interrelated and uncertain variables including changing interest rates, utility sector market performance, ComEd's capital structure, market power prices, post-2006 rate regulatory structures, operating and capital expenditure requirements and other factors. Changes in these variables or in how they interrelate could result in a future impairment of goodwill at Energy Delivery, which could be material. Based on Energy Delivery's expected cash flows, we do not anticipate a goodwill impairment at Exelon through the end of ComEd's transition period in 2006. However, a hypothetical decrease of approximately 15% in Energy Delivery's expected discounted cash flows could trigger an impairment of goodwill.

Exelon Services and InfraSource. Our annual assessment of goodwill impairment at the Exelon Services reporting unit (within our Enterprises segment) was also performed as of November 1, 2003. As we are actively negotiating to sell entities within the Exelon Services reporting unit, we used these negotiations as the basis for the fair value of the Exelon Services reporting unit used in Step I of the analysis. Our assumptions regarding estimated sales prices are subject to change as we continue to negotiate these transactions.

The first step of the annual impairment analysis, comparing the fair value of a reporting unit to its carrying value, including goodwill, indicated an impairment of the Exelon Services goodwill. The second step of the analysis, which compared the implied fair value of Exelon Services' goodwill to the carrying value, indicated that the total goodwill of $24 million recorded at the Exelon Services reporting unit was impaired.

Due to the sale of certain of our InfraSource businesses, we performed an interim assessment of the goodwill recorded at the InfraSource reporting unit during the second quarter of 2003 and in advance of the annual assessment, which would have been performed as of November 1. Based upon this interim assessment, we recorded an impairment charge of approximately $48 million (before minority interest and income taxes) to fully impair this goodwill. We primarily considered the negotiated sales price of InfraSource in determining the need for an interim assessment and the amount of the goodwill impairment charge.

We recorded our 2003 goodwill impairment charges related to the Exelon Services and InfraSource reporting units as operating and maintenance expense within our Consolidated Statements of Income. As of December 31, 2003, there was no goodwill recorded within our Consolidated Balance Sheets related to the reporting units of the Enterprises segment.

Severance Accounting

As part of the implementation of The Exelon Way, we identified approximately 1,500 positions for elimination by the end of 2004 and we are considering whether there are additional positions for elimination in 2005 and 2006. We provide severance benefits to terminated employees pursuant to pre-existing severance plans primarily based upon each individual employee's years of service with us and compensation level. We recorded charges in 2003 related to severance benefits that were considered probable and could be reasonably estimated in accordance with SFAS No. 112, "Employer's Accounting for Postemployment Benefits, an amendment of FASB Statements No. 5 and 43" (SFAS No. 112). A significant assumption in calculating the severance charge was the determination of the number of positions to be eliminated. We based our estimates on our current plans and our ability to determine the appropriate staffing levels to effectively operate the businesses. We may incur further severance costs associated with The Exelon Way if additional positions are identified for elimination. These costs will be recorded in the period in which the costs can be reasonably estimated.

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. See Note 14 of the Notes to Consolidated Financial Statement for further information regarding the accounting for our defined benefit pension plans and postretirement welfare benefit plans.

The costs of providing benefits under these plans are dependent on historical information such as employee age, length of service and level of compensation, and the actual rate of return on plan assets. Also, 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.

The selection of key actuarial assumptions utilized in the measurement of the plan obligations and costs drives the results of the analysis and the resulting charges. The long-term expected rate of return on plan assets (EROA) assumption used in calculating 2003 pension cost was 9.00% compared to 9.50% for 2002 and 2001. The weighted average EROA assumption used in calculating 2003 other postretirement benefit costs was 8.40% compared to 8.80% for 2002 and 2001. A lower EROA is used in the calculation of other postretirement benefit costs, as the other postretirement benefit trust activity is partially taxable while the pension trust activity is non-taxable. The Moody's Aa Corporate Bond Index was used as the basis in selecting the discount rate for determining the plan obligations, using 6.25% at December 31, 2003 compared to 6.75% at December 31, 2002 and 7.35% at December 31, 2001. The reduction in discount rate is due to the decline in Moody's Aa Corporate Bond Index in 2003 and 2002.

The following tables illustrate the effects of changing the major actuarial assumptions discussed above:

Change in Actuarial Assumption	Impact on Projected Benefit Obligation at December 31, 2003	Impact on Pension Liability at December 31, 2003	Impact on 2004 Pension Cost
Pension benefits			
Decrease discount rate by 0.5%	$548	$481	$ 37
Decrease rate of return on plan assets by 0.5%	–	–	34

Change in Actuarial Assumption	Impact on Other Postretirement Benefit Obligation at December 31, 2003	Impact on Postretirement Benefit Liability at December 31, 2003	Impact on 2004 Postretirement Benefit Cost
Postretirement benefits			
Decrease discount rate by 0.5%	$ 178	$ –	$20
Decrease rate of return on plan assets by 0.5%	–	–	5

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

We incurred approximately $320 million in costs in 2003 associated with our pension and postretirement benefit plans, inclusive of curtailment costs of $80 million associated with The Exelon Way. Although 2004 pension and postretirement benefit costs will depend on market conditions, our estimate is that our pension and postretirement benefit costs will not change significantly in 2004 as compared to 2003.

Taxation

We are required to make judgments regarding the potential tax effects of various financial transactions and our ongoing operations to estimate our obligations to taxing authorities. These tax obligations include income, real estate, use and employment-related taxes and ongoing appeals related to these tax matters. These judgments include reserves for potential adverse outcomes regarding tax positions that we have taken. We must also assess our ability to generate capital gains in future periods to realize tax benefits associated with capital losses expected to be generated in future periods. Capital losses may be deducted only to the extent of capital gains realized during the year of the loss or during the three prior or five succeeding years. As of December 31, 2003, we have not recorded an allowance against our deferred tax assets associated with impairment losses which will become capital losses when realized for income tax purposes. We believe these deferred tax assets will be realized in future periods. While we believe the resulting tax reserve balances as of December 31, 2003 reflect the most likely probable expected outcome of these tax matters in accordance with SFAS No. 5, "Accounting for Contingencies," and SFAS No. 109, "Accounting for Income Taxes," the ultimate outcome of such matters could result in additional adjustments to our consolidated financial statements and such adjustments could be material.

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 Energy Delivery and Exelon Energy Company's energy sales to individual customers, however, is based on systematic readings of customer meters generally on a monthly basis. At the end of each month, amounts of energy delivered to customers 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 or gas throughput volume, estimated customer usage by class, estimated losses of energy during delivery to customers and applicable customer rates. Customer accounts receivable as of December 31, 2003 included an estimate of $452 million for unbilled revenue as a result of unread meters at Energy Delivery and Exelon Energy Company. 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; however, total operating revenues would remain unchanged.

The determination of Generation's energy sales is based on estimated amounts delivered as well as fixed quantity sales. At the end of each month, amounts of energy delivered to customers during the month and corresponding unbilled revenue are recorded. Customer accounts receivable as of December 31, 2003 include unbilled energy revenues of $366 million at Generation. Increases in volumes delivered to the wholesale customers in the period would increase unbilled revenue.

Environmental Costs

As of December 31, 2003, we had accrued liabilities of $129 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 $105 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 $24 million of the accrued liabilities total above. Estimates can be affected by the factors noted above as well as by changes in technology, 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 policy 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, vice president of strategy, vice president of audit services and officers from each of the business units. The RMC reports to the Exelon Board of Directors on the scope of our derivative and risk management 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, 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. Additionally, we have exposure to commodity price in relation to CTC revenues we collect from ComEd customers.

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 three years. We have an estimated 89% hedge ratio in 2004 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. Energy Delivery's retail load assumptions are based on forecasted average demand. The hedge ratio is not fixed and will vary from time to time depending upon market conditions, demand, energy market option volatility and actual loads. During peak periods 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 approximately a $32 million decrease in net income. This sensitivity assumes an 89% 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 but 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 one percent of our owned and contracted supply of electricity. The trading portfolio is subject to a risk management policy that includes stringent risk management limits including volume, stop-loss and value-at-risk limits to manage exposure to market risk. Additionally, the Exelon risk management group and Exelon's RMC monitor the financial risks of the power marketing activities.

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 Policies and 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 tables describe the drivers of our energy trading and marketing business and gross margin included in the income statement for the years ended December 31, 2003 and 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 these tables 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).

For the year ended December 31, 2003	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(b)	207	1	208
Changes in valuation techniques and assumptions	–	–	–
Reclassification to realized at settlement of contracts	(223)	(4)	(227)
Total change in unrealized fair value	(16)	(3)	(19)
Realized net settlement of transactions subject to mark-to-market	223	4	227
Total mark-to-market activities gross margin	$ 207	$ 1	$ 208
Accrual activities:			
Accrual activities revenue	$ 5,187	$ –	$ 5,187
Hedge gains reclassified from OCI	2,358	–	2,358
Total revenue—accrual activities	7,545	–	7,545
Fuel and purchased power	2,107	–	2,107
Hedges of fuel and purchased power reclassified from OCI	2,631	–	2,631
Total fuel and purchased power	4,738	–	4,738
Total accrual activities gross margin	2,807	–	2,807
Total gross margin(c)	$ 3,014	$ 1	$ 3,015

(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) Includes hedge ineffectiveness, recorded in earnings of $1 million.
(c) 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 15 of the Notes to Consolidated Financial Statements for further information.

For the year ended December 31, 2002	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 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(b)	$ 2,634	$(29)	$ 2,605

(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 15 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, 2003. It indicates the drivers behind changes in the balance sheet amounts. This table incorporates the mark-to-market activities that are immediately recorded in earnings, as 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)
Total change in fair value during 2003 of contracts recorded in earnings	206	–	206
Reclassification to realized at settlement of contracts recorded in earnings	(223)	(4)	(227)
Reclassification to realized at settlement from OCI	273	–	273
Effective portion of changes in fair value–recorded in OCI	(305)	–	(305)
Total mark-to-market energy contract net assets (liabilities) at December 31, 2003	$ (217)	$ 1	$ (216)

The following table details the balance sheet classification of the mark-to-market energy contract net assets (liabilities) recorded as of December 31, 2003:

	Normal Operations and Hedging Activities	Proprietary Trading	Total
Current assets	$ 319	$ 3	$ 322
Noncurrent assets	99	1	100
Total mark-to-market energy contract assets	418	4	422
Current liabilities	(502)	(3)	(505)
Noncurrent liabilities	(133)	–	(133)
Total mark-to-market energy contract liabilities	(635)	(3)	(638)
Total mark-to-market energy contract net assets (liabilities)	$ (217)	$ 1	$ (216)

The following table details the balance sheet classification of the mark-to-market energy contract net assets (liabilities) 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, region and product. The remainder of the assets represents contracts for which external valuations are not available, primarily option contracts. These contracts are valued using the Black model, an industry standard option valuation model. The fair values in each category reflect the level of forward prices and volatility factors as of December 31, 2003 and may change as a result of changes in these factors. Management uses its best estimates to determine the fair value of commodity and derivative contracts it holds and sells. These estimates consider various factors including closing exchange and over-the-counter price quotations, time value, volatility factors and credit exposure. It is possible, however, that future market prices could vary from those used in recording assets and liabilities from energy marketing and trading activities and such variations could be material.

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

	Maturities within						
	2004	2005	2006	2007	2008	2009 and Beyond	Total Fair Value
Normal operations, qualifying cash-flow hedge contracts(1):							
Actively quoted prices	$ 32	$ –	$ –	$ –	$–	$–	$ 32
Prices provided by other external sources	(219)	(23)	(8)	–	–	–	(250)
Total	$(187)	$(23)	$(8)	$ –	$–	$–	$(218)
Normal operations, other derivative contracts(2):							
Actively quoted prices	$ 23	$ –	$ –	$ –	$–	$–	$ 23
Prices provided by other external sources	(26)	9	5	–	–	–	(12)
Prices based on model or other valuation methods	7	(5)	(9)	(3)	–	–	(10)
Total	$ 4	$ 4	$(4)	$(3)	$–	$–	$ 1
Proprietary trading, other derivative contracts(3):							
Actively quoted prices	$ 1	$ –	$ –	$ –	$–	$–	$ 1
Prices provided by other external sources	(1)	1	–	–	–	–	–
Prices based on model or other valuation methods	–	–	–	–	–	–	–
Total	$ –	$ 1	$ –	$ –	$–	$–	$ 1
Average tenor of proprietary trading portfolio(4)							1.0 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 our 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, 2003. The data in the table gives an indication of the magnitude of SFAS No. 133 hedges Generation has in place; however, since under SFAS No. 133 not all hedges are recorded in OCI, the table does not provide an all-encompassing picture of Generation's hedges. The table also includes a roll-forward of Accumulated Other Comprehensive Income related to cash-flow hedges for the years ended December 31, 2003 and 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	$ (2)	$ 45
Changes in fair value	(128)	(3)	(131)
Reclassifications from OCI to net income	(33)	–	(33)
Accumulated OCI, December 31, 2002	(114)	(5)	(119)
Changes in fair value	(186)	(8)	(194)
Reclassifications from OCI to net loss	167	–	167
Accumulated OCI derivative loss at December 31, 2003	$(133)	$(13)	$(146)

(1) Includes interest-rate hedges at Generation.

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, 2003.

	Proprietary Trading VaR 2003
95% Confidence level, one-day holding period, one-tailed	
Period end	$ –
Average for the period	(0.1)
High	(0.2)
Low	–
95% Confidence level, ten-day holding period, two-tailed	
Period end	$ (0.1)
Average for the period	(0.5)
High	(0.9)
Low	(0.1)
99% Confidence level, one-day holding period, two-tailed	
Period end	$ –
Average for the period	(0.2)
High	(0.3)
Low	–

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

ComEd's CTC revenues are also collected from customers who elect to purchase energy from an ARES. ComEd's CTC rates are reset once a year in the spring, and customers can elect to lock in their CTC rates for a one-, two- or three-year term. Based on the current customers who have elected the one-year CTC rates, we have performed a sensitivity analysis to determine the net impact of a 10% increase in the average market price of electricity which would result in a $14 million decrease in CTC revenues. A 10% decrease in market prices would result in a $14 million increase in CTC revenues. The result may be significantly affected if additional customers elect to purchase energy from an ARES or if customers elect to purchase their energy from us.

Credit Risk

Credit risk for Energy Delivery is managed by the credit and collection policies of ComEd and PECO, 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, 2003, ComEd's ten largest customers represented approximately 2% of its retail electric revenues and PECO's ten largest customers represented approximately 7% of its retail electric and gas 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 tables provide information on Generation's credit exposure, net of collateral, as of December 31, 2003 and 2002. They further delineate that exposure by the credit rating of the counterparties and provide guidance on the concentration of credit risk to individual counterparties and an indication of the maturity of a company's credit risk by credit rating of the counterparties. The figures in the tables below do not include sales to Generation's affiliates or exposure through ISOs which are discussed below.

Rating as of December 31, 2003	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	$116	$–	$116	1	$20
Non-investment grade	22	7	15	–	–
No external ratings					
Internally rated–investment grade	13	–	13	–	–
Internally rated–non-investment grade	1	–	1	–	–
Total	$152	$7	$145	1	$20

Rating as of December 31, 2002	Total Exposure Before Credit Collateral	Credit Collateral	Net Exposure	Number Of Counterparties Greater th an 10% of Net Exposure	Net Exposure Of Counterparties Greater than 10% of Net Exposure
Investment grade	$ 156	$ –	$156	2	$ 71
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

	Maturity of Credit Risk Exposure			
Rating as of December 31, 2003	Less than 2 Years	2-5 Years	Exposure Greater than 5 Years	Total Exposure Before Credit Collateral
Investment grade	$101	$15	$–	$116
Non-investment grade	22	–	–	22
No external ratings				
Internally rated–investment grade	13	–	–	13
Internally rated–non-investment grade	1	–	–	1
Total	$137	$15	$–	$152

Dynegy. 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. Generation has credit risk associated with Dynegy through Generation's equity investment in Sithe. Sithe is a 60% owner of the Independence generating station, a 1,028-MW gas-fired facility that has an energy-only long-term tolling agreement with Dynegy, with a related financial swap arrangement. Sithe has entered into a contract to purchase the remaining 40% interest of the Independence generating station. As of December 31, 2003, 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 50% owner of Sithe, that the impairment would result in an after-tax reduction of our equity earnings of approximately $5 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, Sithe 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 up to $30 million, net of a FIN No. 45 guarantee recorded in connection with Generation's sale of 50% of Sithe to Reservoir. In the event of a sale of Exelon's investment in Sithe to a third party, proceeds from the sale could be negatively affected by up to $74 million, which would represent an after-tax loss of up to $43 million. Additionally, the future economic value of AmerGen's purchased power arrangement with Illinois Power Company, a subsidiary of Dynegy, could be affected by events related to Dynegy's financial condition. On February 3, 2004, Dynergy announced an agreement to sell its subsidiary Illinois Power Company to a third party, which, upon closing of the transaction, would reduce Generation's credit risk associated with Dynergy.

Midwest Generation. ComEd and Generation are parties to various transactions with Midwest Generation, a subsidiary of Edison Mission Energy (EME) and Edison Mission Midwest Holdings (EMMH). Although earlier public filings in 2003 by EME indicated credit issues, a filing in December 2003 indicated that EMMH has secured financing and re-paid its significant current debts. Thus, Exelon's credit contingency risk associated with Midwest Generation has decreased during the fourth quarter of 2003.

Collateral. As part of the normal course of business, we routinely enter into physical or financially settled contracts for the purchase and sale of capacity, energy, fuels and emissions allowances. These contracts either contain express provisions or otherwise permit our counterparties and us to demand adequate assurance of future performance when there are reasonable grounds for doing so. In accordance with the contracts and applicable law, if we are downgraded by a credit rating agency, especially if such downgrade is to a level below investment grade, it is possible that a counterparty would attempt to rely on such a downgrade as a basis for making a demand for adequate assurance of future performance. Depending on our net position with a counterparty, the demand could be for the posting of collateral. In the absence of expressly agreed to provisions that specify the collateral that must be provided, the obligation to supply the collateral requested will be a function of the facts and circumstances of our situation at the time of the demand. If we can reasonably claim that we are willing and financially able to perform our obligations, it may be possible to successfully argue that no collateral should be posted or that only an amount equal to two or three months of future payments should be sufficient.

ISOs. Generation participates in the following established, real-time energy markets, which are administered by ISOs: PJM, ISO New England, 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.

Direct Financing Leases. Our consolidated balance sheet included a $465 million net investment in direct financing leases as of December 31, 2003. The investment in direct financing leases represents future minimum lease payments due at the end of the thirty-year lives of the leases of $1,492 million, less unearned income of $1,027 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 these direct financing leases.

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, 2003, a hypothetical 10% increase in the interest rates associated with variable-rate debt would result in a $1 million decrease in pre-tax earnings for 2004.

ComEd has entered into fixed-to-floating interest-rate swaps in order to maintain its targeted percentage of variable-rate debt associated with fixed-rate debt issuances in the aggregate amount of $485 million. At December 31, 2003, these interest-rate swaps, designated as fair-value hedges, had an aggregate fair market value of $33 million based on the present value difference between the contract and market rates at December 31, 2003. If these derivative instruments had been terminated at December 31, 2003, this estimated fair value represents the amount that would be paid by the counterparties to ComEd.

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, 2003 is estimated to be $39 million. If the derivative instruments had been terminated at December 31, 2003, 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, 2003 is estimated to be $28 million. If the derivative instruments had been terminated at December 31, 2003, this estimated fair value represents the amount the counterparties would pay us.

In 2003, ComEd entered into forward-starting interest-rate swaps in the aggregate notional amount of $440 million to lock in interest-rate levels in anticipation of future financings. The debt issuances that these swaps were hedging were considered probable; therefore, ComEd accounted for these interest-rate swap transactions as hedges. In connection with the 2003 issuances of First Mortgage Bonds, forward-starting interest-rate swaps with an aggregate notional amount of $1,070 million were settled with net cash proceeds to counterparties of $45 million that has been deferred in regulatory assets and is being amortized over the life of the First Mortgage Bonds as a net increase to interest expense. At December 31, 2003, ComEd has settled all of its interest-rate swaps, designated as cash-flow hedges.

In 2003, PECO entered into forward-starting interest-rate swaps in the aggregate notional amount of $360 million to lock in interest-rate levels in anticipation of future financings, in connection with the issuance of First and Refunding Mortgage Bonds. The debt issuances that these swaps were hedging were considered probable; therefore, PECO accounted for these interest-rate swap transactions as hedges. PECO settled these swaps for net cash proceeds of $1 million, which was recorded in other comprehensive income and is being amortized over the life of the debt issuance.

PETT has 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 $11 million at December 31, 2003. As of December 31, 2003 PETT, a wholly owned subsidiary, was deconsolidated from the financial statements of PECO.

Under the terms of the Boston Generating Facility, Boston Generating is required to effectively fix the interest rate on 50% of borrowings under the facility through its maturity in 2007. As of December 31, 2003, Boston Generating had entered into interest-rate swap agreements that effectively fixed the interest-rate on $861 million of notional principal, or approximately 83% of borrowings outstanding under the Boston Generating Facility at December 31, 2003. The fair market value exposure of these swaps, designated as cash-flow hedges, was $77 million based on the present value differences between the contract and market rates at December 31, 2003.

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, 2003 is estimated to be $89 million. If the derivative instruments had been terminated at December 31, 2003, 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, 2003 is estimated to be $65 million. If the derivative instruments had been terminated at December 31, 2003, this estimated fair value represents the amount we would pay to the counterparties.

In January 2004, the counterparties terminated the interest-rate swaps with Boston Generating. The total net value of these swaps as of the respective termination dates was $82 million, which is a net payable to the counterparties.

In 2003, Generation entered into forward-starting interest-rate swaps in the aggregate notional amount of $500 million to lock in interest-rate levels in anticipation of future financings. The debt issuances that these swaps are hedging were considered probable; therefore, Generation accounted for these interest-rate swap transactions as hedges. In connection with Generation's 2003 issuance of Senior Notes, Generation settled swaps with an aggregate notional amount of $500 million for net cash proceeds of $1 million, which was recorded in other comprehensive income and is being amortized over the life of the debt issuance.

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, 2003, 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 $303 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

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

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.

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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, 2003 and December 31, 2002, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2003 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 1 to the consolidated financial statements, Exelon changed its method of accounting for derivative instruments and hedging activities as of January 1, 2001, its method of accounting for goodwill as of January 1, 2002, its method of accounting for asset retirement obligations as of January 1, 2003 and its method of accounting for variable interest entities in 2003.

PricewaterhouseCoopers LLP

Chicago, Illinois
January 28, 2004

Consolidated Statements of Income

EXELON CORPORATION AND SUBSIDIARY COMPANIES

in millions, except per share data	2003	2002	2001
	For the Years Ended December 31,		
Operating revenues	$15,812	$14,955	$14,918
Operating expenses			
Purchased power	3,459	3,262	3,156
Purchased power from AmerGen Energy Company, LLC	382	273	57
Fuel	2,534	1,727	1,877
Impairment of Boston Generating, LLC long-lived assets	945	–	–
Operating and maintenance	4,587	4,345	4,394
Depreciation and amortization	1,126	1,340	1,449
Taxes other than income	581	709	623
Total operating expenses	13,614	11,656	11,556
Operating income	2,198	3,299	3,362
Other income and deductions			
Interest expense, net of amounts capitalized	(881)	(966)	(1,107)
Distributions on preferred securities of subsidiaries	(39)	(45)	(49)
Equity in earnings of unconsolidated affiliates	33	80	62
Other, net	(187)	300	79
Total other income and deductions	(1,074)	(631)	(1,015)
Income before income taxes and cumulative effect of changes in accounting principles	1,124	2,668	2,347
Income taxes	331	998	931
Income before cumulative effect of changes in accounting principles	793	1,670	1,416
Cumulative effect of changes in accounting principles (net of income taxes of $69, $(90) and $8 in 2003, 2002 and 2001, respectively)	112	(230)	12
Net income	$ 905	$ 1,440	$ 1,428
Average shares of common stock outstanding			
Basic	326	322	320
Diluted	329	325	322
Earnings per average common share—basic:			
Income before cumulative effect of changes in accounting principles	$ 2.44	$ 5.18	$ 4.42
Cumulative effect of changes in accounting principles	0.34	(0.71)	0.04
Net income	$ 2.78	$ 4.47	$ 4.46
Earnings per average common share—diluted:			
Income before cumulative effect of changes in accounting principles	$ 2.41	$ 5.15	$ 4.39
Cumulative effect of changes in accounting principles	0.34	(0.71)	0.04
Net income	$ 2.75	$ 4.44	$ 4.43
Dividends per common share	$ 1.92	$ 1.76	$ 1.82

See Notes to Consolidated Financial Statements

in millions	For the Years Ended December 31, 2003	2002	2001
Cash flows from operating activities			
Net income	**$ 905**	$ 1,440	$ 1,428
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation, amortization and accretion, including nuclear fuel	**1,718**	1,701	1,834
Cumulative effect of changes in accounting principles (net of income taxes)	**(112)**	230	(12)
Impairment of investments	**309**	41	36
Impairment of goodwill and long-lived assets	**990**	–	–
Deferred income taxes and amortization of investment tax credits	**(337)**	278	(68)
Provision for uncollectible accounts	**94**	129	145
Loss (gain) on sale of investments	**25**	(199)	–
Equity in earnings of unconsolidated affiliates	**(33)**	(80)	(62)
Net realized losses on nuclear decommissioning trust funds	**16**	32	127
Other operating activities	**57**	126	143
Changes in assets and liabilities:			
Accounts receivable	**21**	(448)	318
Inventories	**(54)**	(37)	(33)
Other current assets	**(84)**	45	62
Accounts payable, accrued expenses and other current liabilities	**18**	420	(144)
Pension and non-pension postretirement benefits obligations	**(144)**	(165)	(41)
Other noncurrent assets and liabilities	**(5)**	129	(118)
Net cash flows provided by operating activities	**3,384**	3,642	3,615
Cash flows from investing activities			
Capital expenditures	**(1,954)**	(2,150)	(2,088)
Proceeds from liquidated damages	**92**	–	–
Proceeds from nuclear decommissioning trust fund sales	**2,341**	1,612	1,624
Investment in nuclear decommissioning trust funds	**(2,564)**	(1,824)	(1,863)
Note receivable from unconsolidated affiliate	**35**	(35)	–
Proceeds from the sales of investments	**263**	287	–
Acquisitions of businesses, net of cash acquired	**(272)**	(445)	(30)
Change in restricted cash	**(92)**	(24)	(58)
Other investing activities	**42**	17	(35)
Net cash flows used in investing activities	**(2,109)**	(2,562)	(2,450)
Cash flows from financing activities			
Issuance of long-term debt	**3,015**	1,223	2,270
Retirement of long-term debt	**(2,922)**	(2,134)	(1,860)
Change in short-term debt	**(355)**	321	(1,013)
Issuance of long-term debt to financing affiliates	**103**	–	–
Issuance of mandatorily redeemable preferred securities	**200**	–	–
Retirement of mandatorily redeemable preferred securities	**(250)**	(18)	(17)
Payment on acquisition note payable to Sithe Energies, Inc.	**(446)**	–	–
Retirement of preferred stock	**(50)**	–	–
Dividends paid on common stock	**(620)**	(563)	(583)
Proceeds from employee stock plans	**181**	75	39
Contribution from minority interest of consolidated subsidiary	**–**	43	–
Other financing activities	**(96)**	(43)	(42)
Net cash flows used in financing activities	**(1,240)**	(1,096)	(1,206)
Increase (decrease) in cash and cash equivalents	**35**	(16)	(41)
Cash and cash equivalents at beginning of period	**469**	485	526
Cash and cash equivalents, including cash held for sale	**504**	469	485
Cash classified as held for sale on the consolidated balance sheet	**11**	–	–
Cash and cash equivalents at end of period	**$ 493**	$ 469	$ 485

See Notes to Consolidated Financial Statements

Consolidated Balance Sheets

EXELON CORPORATION AND SUBSIDIARY COMPANIES

in millions	December 31, 2003	2002
Assets		
Current assets		
Cash and cash equivalents	**$ 493**	$ 469
Restricted cash	**97**	396
Accounts receivable, net		
Customer	**1,889**	2,076
Other	**343**	323
Inventories, at average cost		
Fossil fuel	**212**	175
Materials and supplies	**310**	306
Notes receivable from affiliate	**92**	–
Deferred income taxes	**474**	6
Assets held for sale	**242**	–
Other	**428**	374
Total current assets	**4,580**	4,125
Property, plant and equipment, net	**20,630**	17,957
Deferred debits and other assets		
Regulatory assets	**5,226**	5,546
Nuclear decommissioning trust funds	**4,721**	3,053
Investments	**837**	1,403
Goodwill	**4,719**	4,992
Notes receivable from financing trusts	**114**	–
Other	**1,114**	793
Total deferred debits and other assets	**16,731**	15,787
Total assets	**$ 41,941**	$37,869

See Notes to Consolidated Financial Statements

in millions	December 31, 2003	2002
Liabilities and shareholders' equity		
Current liabilities		
Commercial paper	**$ 326**	$ 681
Note payable to Sithe Energies, Inc.	**90**	534
Long-term debt due within one year	**1,385**	1,402
Long-term debt to ComEd Transitional Funding Trust and PECO Energy Transitional Trust due within one year	**470**	–
Accounts payable	**1,822**	1,607
Accrued expenses	**1,228**	1,354
Liabilities held for sale	**61**	–
Other	**306**	296
Total current liabilities	**5,688**	5,874
Long-term debt	**7,889**	13,127
Long-term debt due to ComEd Transitional Funding Trust and PECO Energy Transitional Trust	**5,055**	–
Long-term debt to financing trusts	**545**	–
Deferred credits and other liabilities		
Deferred income taxes	**4,357**	3,702
Unamortized investment tax credits	**288**	301
Nuclear decommissioning liability for retired plants	**–**	1,293
Asset retirement obligations	**2,997**	–
Pension obligations	**1,668**	1,959
Non-pension postretirement benefits obligations	**1,053**	877
Spent nuclear fuel obligation	**867**	858
Regulatory liabilities	**1,891**	486
Other	**1,053**	978
Total deferred credits and other liabilities	**14,174**	10,454
Total liabilities	**33,351**	29,455
Commitments and contingencies		
Minority interest of consolidated subsidiaries	**–**	77
Preferred securities of subsidiaries	**87**	595
Shareholders' equity		
Common stock	**7,292**	7,059
Deferred compensation	**–**	(1)
Retained earnings	**2,320**	2,042
Accumulated other comprehensive income (loss)	**(1,109)**	(1,358)
Total shareholders' equity	**8,503**	7,742
Total liabilities and shareholders' equity	**$41,941**	$37,869

See Notes to Consolidated Financial Statements

Consolidated Statements of Changes in Shareholders' Equity

EXELON CORPORATION AND SUBSIDIARY COMPANIES

Dollars in millions, shares in thousands	Shares	Common Stock	Deferred Compensation	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Shareholders' Equity
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
Net income		–	–	905	–	905
Long-term incentive plan activity	4,661	222	–	–	–	222
Employee stock purchase plan issuances	209	11	–	–	–	11
Amortization of deferred compensation		–	1	–	–	1
Common stock dividends declared		–	–	(625)	–	(625)
Redemption premium on PECO preferred stock		–	–	(2)	–	(2)
Other comprehensive income, net of income taxes of $217		–	–	–	249	249
Balance, December 31, 2003	**328,183**	**$ 7,292**	**$ –**	**$2,320**	**$(1,109)**	**$8,503**

Consolidated Statements of Comprehensive Income

EXELON CORPORATION AND SUBSIDIARY COMPANIES

in millions	For the Years Ended December 31, 2003	2002	2001
Net income	**$ 905**	$ 1,440	$1,428
Other comprehensive income (loss)			
Minimum pension liability, net of income taxes of $16 and $(597), respectively	**26**	(1,007)	—
SFAS No. 133 transition adjustment, net of income taxes of $32	**—**	—	44
SFAS No. 143 transition adjustment, net of income taxes of $167	**168**	—	—
Cash-flow hedge fair value adjustment, net of income taxes of $3, $(132) and $17, respectively	**3**	(199)	22
Foreign currency translation adjustment, net of income taxes of $0	**3**	—	(1)
Unrealized gain (loss) on marketable securities, net of income taxes of $6, $(116), and $(40), respectively	**7**	(119)	(41)
Interest in other comprehensive income (loss) of unconsolidated affiliates, net of income taxes of $25, $(5) and $(16), respectively	**42**	(7)	(27)
Total other comprehensive income (loss)	**249**	(1,332)	(3)
Total comprehensive income	**$1,154**	$ 108	$1,425

See Notes to Consolidated Financial Statements

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

NOTE 01 • SIGNIFICANT ACCOUNTING POLICIES

Description of Business

Exelon Corporation (Exelon) is a utility services holding company engaged, through its subsidiaries, in the energy delivery, wholesale generation and other businesses discussed below (see Note 21 – Segment Information). The Energy Delivery segment's businesses include the purchase and sale of electricity and distribution and transmission services by Commonwealth Edison Company (ComEd) in northern Illinois and PECO Energy Company (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 equity interest in Sithe Energies, Inc. (Sithe). Exelon Enterprises Company, LLC (Enterprises) includes energy and infrastructure services, competitive retail energy sales, a communications joint venture and other investments weighted towards the communications, energy services and retail services industries.

Basis of Presentation

The consolidated financial statements include the accounts of its majority-owned subsidiaries, except certain financing trusts of ComEd and PECO for 2003, 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 owned 95% prior to its sale in the third quarter of 2003 and Southeast Chicago Energy Project, LLC (Southeast Chicago) of which Exelon owns 74% 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. In conjunction with the adoption of Statement of Financial Accounting Standards (SFAS) No. 150, "Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity" (SFAS No. 150) on July 1, 2003, Exelon reclassified the minority interest associated with Southeast Chicago to a long-term liability. The total minority interest related to Southeast Chicago was $51 million as of December 31, 2003. In accordance with SFAS No. 150, prior periods were not restated.

Certain trusts and limited partnerships that are financing subsidiaries of ComEd and PECO have issued debt or mandatorily redeemable preferred securities. Due to the adoption of the Financial Accounting Standards Board (FASB) Interpretation No. 46 (revised December 2003), "Consolidation of Variable Interest Entities" (FIN No. 46-R), these trusts and limited partnerships are no longer consolidated within Exelon's financial statements as of December 31, 2003 or, in one case, July 1, 2003. See below – Variable Interest Entities for further discussion of the deconsolidation of these financing entities and the adoption of FIN No. 46-R.

Reclassifications

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

Use of Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States 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 costs and asset retirement obligations, fixed asset depreciation, asset and goodwill impairments, severance, pension and other postretirement benefits, taxes, unbilled energy revenues and environmental costs.

Accounting for the Effects of Regulation

Exelon accounts for all of its regulated electric and gas operations in accordance with accounting policies prescribed by the regulatory authorities having jurisdiction, principally the Illinois Commerce Commission (ICC) and the Pennsylvania Public Utility Commission (PUC) under state public utility laws, the Federal Energy Regulatory Commission (FERC) under various Federal laws, and the Securities and Exchange Commission (SEC) under the Public Utility Holding Company Act of 1935 (PUHCA), and applies SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation," (SFAS No. 71) when appropriate. SFAS No. 71 requires Exelon to record in its financial statements the effects of rate regulation for utility operations that meet the following criteria: (1) third-party regulation of rates; (2) cost-based rates; and (3) a reasonable assumption that all costs will be recoverable from customers through rates. Exelon believes that it is probable that currently recorded regulatory assets will be recovered or settled. If a separable portion of Exelon's business no longer meets the provisions of SFAS No. 71, Exelon would be required to eliminate the financial statement effects of regulation for that portion.

Variable Interest Entities

The FASB issued FASB Interpretation No. 46, "Consolidation of Variable Interest Entities" in January 2003 (FIN No. 46) and subsequently issued its revision in FIN No. 46-R in December 2003 which addressed the requirements for consolidating certain variable interest entities. FIN No. 46 was effective for Exelon's variable interest entities created after January 31, 2003 and FIN No. 46-R was effective December 31, 2003 for Exelon's other variable interest entities that are considered to be special-purpose entities. FIN No. 46-R applies to all other variable interest entities as of March 31, 2004.

PECO Energy Capital Trust IV (PECO Trust IV), a financing subsidiary of PECO created in May 2003, was not consolidated within the financial statements of Exelon pursuant to the provisions of FIN No. 46 as of July 1, 2003. As of December 31, 2003, the remaining financing trusts of ComEd and PECO, including ComEd Financing II, ComEd Financing III, ComEd Funding LLC, ComEd Transitional Funding Trust, PECO Energy Capital Trust III (PECO Trust III) and PECO Energy Transition Trust (PETT), were deconsolidated within the financial statements of Exelon pursuant to the provisions of FIN No. 46-R. Amounts of $6.1 billion owed to these financing trusts were recorded as debt to financing trusts within the Consolidated Balance Sheets at December 31, 2003. This change in presentation had no impact on net income of Exelon. In accordance with FIN No. 46-R, prior periods have not been represented.

Revenues

Operating 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 customers (see Note 5 – Accounts Receivable).

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 term and the recoverability of costs related to change orders. Changes in these estimates could result in variability of earnings. At December 31, 2003 and 2002, current assets included $27 million and $70 million, respectively, of costs and earnings in excess of billings on uncompleted contracts and current liabilities included $21 million and $44 million, respectively, of billings and earnings in excess of costs on uncompleted contracts.

At December 31, 2003 and 2002, accounts receivable included $32 million and $49 million, respectively, of contract retention. These amounts represent revenue recognized on costs incurred that is not 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.

Option Contracts, Swaps, and Commodity Derivatives. Premiums received and paid on option contracts and swap arrangements not considered derivatives 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 operating revenues.

Trading Activities. In the third quarter of 2002, Exelon adopted the provisions of Emerging Issues Task Force (EITF) Issue No. 02-3, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities" (EITF 02-3), which required 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 in Exelon's Consolidated Statements of Income. For comparative purposes, energy costs related to energy trading have been reclassified in prior periods to conform to the net basis of presentation required by EITF 02-3. Exelon commenced trading activities in April 2001. For the year ended December 31, 2001, $207 million of purchased power expense and $15 million of fuel expense were reclassified and reflected as a reduction to revenue.

Stock-Based Compensation

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). Exelon adopted the additional disclosure requirements of SFAS No. 148 in 2002 and continues to account for its stock-compensation plans under the disclosure-only provision of SFAS No. 123, "Accounting for Stock-Based Compensation" (SFAS No. 123). See Note 17—Common Stock for further discussion of Exelon's stock-compensation 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, 2003, 2002 and 2001:

	2003	2002	2001
Net income–as reported	**$ 905**	$1,440	$1,428
Deduct: Total stock-based compensation expense determined under fair-value method for all awards, net of income taxes	**20**	33	26
Pro forma net income	**$ 885**	$1,407	$1,402
Earnings per share:			
Basic–as reported	**$ 2.78**	$ 4.47	$ 4.46
Basic–pro forma	**$ 2.72**	$ 4.36	$ 4.38
Diluted–as reported	**$ 2.75**	$ 4.44	$ 4.43
Diluted–pro forma	**$2.69**	$ 4.33	$ 4.35

Income Taxes

Deferred Federal and state income taxes are provided on all significant temporary differences between the book basis and the tax basis of assets and liabilities and for tax benefits carried forward. Investment tax credits previously utilized for income tax purposes have been deferred on the Consolidated Balance Sheets and are recognized in book income over the life of the related property. Pursuant to the Internal Revenue Code, Exelon files a consolidated Federal income tax return that includes its subsidiaries in which it owns at least 80% of the outstanding stock. Income taxes are allocated to each of Exelon's subsidiaries included in the filing of the consolidated Federal income tax return based on the separate return method and records its income tax valuation allowance by assessing which deferred tax assets are more likely than not to be realized in the future (see Note 12 – 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 life of new debt issued to finance the debt redemption 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 20 – 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

As of December 31, 2003, restricted cash primarily represents liquidated damages receipts at Generation and proceeds from a ComEd pollution control bond offering in December 2003 which were applied to redeem pollution control bonds that matured in January 2004. Prior to the adoption of FIN No. 46-R, the restricted cash of ComEd Transitional Funding Trust and PETT was included in Exelon's Consolidated Balance Sheets. This restricted cash reflected escrowed cash to be applied to the principal and interest payments on the debt issued by the financing trusts.

Allowance for Doubtful Accounts

The allowance for doubtful accounts reflects Exelon's best estimate of probable losses inherent in the accounts receivable balance. The allowance is based on known troubled accounts, historical experience, and other currently available evidence.

Inventories

Fossil Fuel. Fossil fuel inventory includes the weighted average cost of stored natural gas, coal, and oil. Fossil fuel also includes propane at cost. PECO has several long-term storage contracts as well as a liquefied natural gas facility.

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

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

Emission Allowances

Emission allowances are included in inventories and deferred debits and other assets and are carried at the lower of cost or market and charged to fuel expense as they are used in operations. Emission allowances can be used from the years 2004 to 2028. As of December 31, 2003 and 2002, emission allowance balances were $105 million and $107 million, respectively.

Marketable Securities

Marketable securities are classified as available-for-sale securities and are reported at fair value. Unrealized gains and losses, net of tax, on nuclear decommissioning trust funds transferred to Generation from PECO and ComEd are reflected in regulatory assets and liabilities on Exelon's Consolidated Balance Sheets. Unrealized gains and losses on nuclear decommissioning trust funds for units acquired after the Merger are reported in other comprehensive income. Prior to the adoption of SFAS No. 143, "Accounting for Asset Retirement Obligations" (SFAS No. 143) on January 1, 2003, unrealized gains and losses on marketable securities held in the nuclear decommissioning trust funds were reported in accumulated depreciation for operating units transferred to Generation from PECO and as other comprehensive income for operating and retired units transferred to Generation from ComEd. At December 31, 2003 and 2002, Exelon had no held-to-maturity securities.

Purchased Gas Adjustment Clause

PECO's natural gas rates are subject to a fuel adjustment clause designed to recover or refund the difference between the actual cost of purchased gas and the amount included in rates. Differences between the amounts billed to customers and the actual costs recoverable are deferred and recovered or refunded in future periods by means of prospective quarterly adjustments to rates. At December 31, 2003 and 2002, deferred energy costs of $81 million and $31 million, respectively, which are expected to be recovered under the adjustment clause, were recorded in other current assets on Exelon's Consolidated Balance Sheets.

Property, Plant and Equipment

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

Upon retirement, the cost of regulated property, net of salvage, is charged to accumulated depreciation and removal costs reduce the related regulatory liability in accordance with the provisions of SFAS No. 71. See Note 6 – Property, Plant and Equipment and Note 20 – Supplemental Financial Information.

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, exclusive of dry cask storage costs, at operating plants are charged to fuel expense as the related fuel is consumed. Costs associated with nuclear outages are recorded in the period incurred. Dry cask storage costs are expensed as incurred.

Capitalized Software Costs

Costs incurred during the application development stage of software projects that are developed or obtained for internal use are capitalized. At December 31, 2003 and 2002, unamortized capitalized software costs totaled $630 million and $491 million, 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. During 2003, 2002 and 2001, Exelon amortized capitalized software costs of $69 million, $64 million and $39 million, respectively.

Depreciation and Amortization

Depreciation is provided over the estimated service lives of property, plant and equipment on a straight-line basis using the composite method. Annual depreciation provisions for financial reporting purposes, expressed as a percentage of average service life for each asset category, are presented in the table below. See Note 6 – Property, Plant and Equipment for information on service life extensions for certain nuclear generating stations and a change in Energy Delivery's depreciation rates.

Asset Category	**2003**	2002	2001
Electric – transmission and distribution	**2.81%**	3.11%	3.97%
Electric – generation	**2.90%**	3.65%	3.11%
Gas	**2.38%**	2.13%	2.34%
Common – gas and electric	**7.53%**	6.40%	6.26%
Other property and equipment	**8.20%**	7.88%	9.53%

Amortization of regulatory assets is provided over the recovery period specified in the related regulatory agreement.

Nuclear Generating Station Decommissioning

Exelon accounts for the costs of decommissioning its nuclear generating stations in accordance with SFAS No. 143. See Note 13 – Nuclear Decommissioning and Spent Fuel Storage for information regarding the adoption and application of SFAS No. 143 and Cumulative Effect of Changes in Accounting Principle below for pro forma net income and earnings per common share for the years ended December 31, 2002 and 2001, adjusted as if SFAS No. 143 had been applied effective January 1, 2001.

Capitalized Interest and Allowance for Funds Used During Construction

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 $15 million, $20 million and $17 million in 2003, 2002 and 2001, 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 20 – Supplemental Financial Information). Exelon recorded charges to AFUDC of $16 million, $19 million and $19 million in 2003, 2002 and 2001, respectively.

Asset Impairments

Long-Lived Assets. Exelon evaluates the carrying value of long-lived assets to be held and used for impairment whenever indications of impairment exist in accordance with the requirements of SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets" (SFAS No. 144). The carrying value of long-lived assets is considered impaired when the projected undiscounted cash flows are less than the carrying value. In that event, a loss would be recognized based on the amount by which the carrying value exceeds the fair value. Fair value is determined primarily by available market valuations or discounted cash flows. See Note 2 – Acquisitions and Dispositions for a description of the impairment recorded in 2003 related to the long-lived assets of Boston Generating, LLC (Boston Generating), formerly known as Exelon Boston Generating, LLC.

Upon meeting certain criteria defined in SFAS No. 144, the assets and associated liabilities that compose a disposal group are classified as held for sale and the carrying value of these assets is adjusted downward, if necessary, to the estimated sales price, less cost to sell. See Note 2 – Acquisitions and Dispositions for a description of assets and liabilities classified as held for sale as of December 31, 2003 and impairments recorded related to these assets.

Goodwill. Goodwill represents the excess of the purchase price paid over the estimated fair value of the assets acquired and liabilities assumed in the acquisition of a business. As of January 1, 2002, Exelon adopted SFAS No. 142, "Goodwill and Other Intangible Assets" (SFAS No. 142). Pursuant to SFAS No. 142, goodwill is no longer amortized but is tested for impairment at least annually or on an interim basis if an event occurs or circumstances change that would reduce the fair value of a reporting unit below its carrying value. Prior to January 1, 2002, goodwill was amortized using the straight-line method over its estimated period of benefit. Goodwill associated with the merger of Exelon, Unicom Corporation (Unicom), and PECO on October 20, 2000 (Merger) was amortized on a straight-line basis over 40 years in 2001. Goodwill associated with other acquisitions was amortized over periods from 10 to 20 years in 2001. See Note 8 – Goodwill for information regarding the adoption of SFAS No. 142 and Cumulative Effect of Changes in Accounting Principles below for pro forma net income and earnings per common share for the year ended December 31, 2001, adjusted as if SFAS No. 142 had been applied effective January 1, 2001.

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

Derivative Financial Instruments

Exelon adopted SFAS No. 133, "Accounting for Derivatives and Hedging Activities" (SFAS No. 133) on January 1, 2001. As a result, 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.

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. Changes in the derivatives recorded at fair value are recognized in earnings unless specific hedge accounting criteria are met, in which case those changes are recorded in other comprehensive income. Gains and losses on "normal" contracts are recognized when the underlying physical transaction affects earnings. 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 thus not required to be recorded at fair value, but on an accrual basis of accounting.

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, 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. Exelon utilizes derivatives with respect to energy transactions 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 energy-related derivatives for trading purposes. 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. Commitments under these contracts are discussed in Note 19—Commitments and Contingencies.

Exelon enters 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.

Cumulative Effect of Changes in Accounting Principles

The following tables set forth Exelon's net income and earnings per common share for the years ended December 31, 2003, 2002 and 2001, adjusted as if SFAS No. 142 and SFAS No. 143 had been applied effective January 1, 2001. SFAS No. 142 and SFAS No. 143 were adopted as of January 1, 2002 and January 1, 2003, respectively.

	2003	2002	2001
Reported net income	**$905**	$1,440	$1,428
Earnings effect of adopting SFAS No. 143	**–**	27	104
Exclusion of goodwill amortization–SFAS No. 142	**–**	–	155
Adjusted net income	**$905**	$1,467	$1,687

	2003	2002	2001
Basis earnings per common share:			
Reported net income	**$2.78**	$ 4.47	$ 4.46
Earnings effect of adopting SFAS No. 143	**–**	0.08	0.32
Exclusion of goodwill amortization–SFAS No. 142	**–**	–	0.48
Adjusted net income	**$2.78**	$ 4.55	$ 5.26

	2003	2002	2001
Diluted earnings per common share:			
Reported net income	**$2.75**	$ 4.44	$ 4.43
Earnings effect of adopting SFAS No. 143	**–**	0.08	0.32
Exclusion of goodwill amortization–SFAS No. 142	**–**	–	0.48
Adjusted net income	**$2.75**	$ 4.52	$ 5.23

See Note 8—Goodwill and Note 13—Nuclear Decommissioning and Spent Fuel Storage for further information regarding the adoptions of SFAS No. 142 and SFAS No. 143, respectively.

New Accounting Pronouncements

Through its postretirement benefit plans, Exelon provides retirees with prescription drug coverage. On December 8, 2003, the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the Prescription Drug Act) was enacted. The Prescription Drug Act introduced a prescription drug benefit under Medicare as well as a Federal subsidy to sponsors of retiree health care benefit plans that provide a benefit that is at least actuarially equivalent to the Medicare prescription drug benefit. In response to the enactment of the Prescription Drug Act, the FASB issued FASB Staff Position (FSP) FAS 106-1 (FSP FAS 106-1) in January 2004, which permits a plan sponsor of a postretirement health care plan that provides a prescription drug benefit to make a one-time election to defer the accounting for the effects of the Prescription Drug Act. Exelon has made the one-time election allowed by FSP FAS 106-1. Thus, any measures of the accumulated projected benefit obligation (APBO) or net periodic postretirement benefit costs in Exelon's financial statements and included in Note 14—Retirement Benefits do not reflect the effects of the Prescription Drug Act on Exelon's postretirement plans. Exelon is evaluating what impact the Prescription Drug Act will have on its postretirement benefit plans and whether it will be eligible for a Federal subsidy beginning in 2006. Specific authoritative guidance on the accounting for the Federal subsidy is pending, and that guidance, when issued, could require Exelon to change previously reported information.

In July 2003, the EITF reached a consensus on EITF Issue No. 03-11, "Reporting Realized Gains and Losses on Derivative Instruments That Are Subject to FASB Statement No. 133, 'Accounting for Derivative Instruments and Hedging Activities,' and Not 'Held for Trading Purposes' as Defined in EITF Issue No. 02-3, 'Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities," (EITF 03-11), which was ratified by the FASB in August 2003. The EITF concluded that determining whether realized gains and losses on physically settled derivative contracts not "held for trading purposes" should be reported in the income statement on a gross or net basis is a matter of judgment that depends on the relevant facts and circumstances. The impact, if any, of adopting EITF 03-11 on Exelon's operating revenues and operating expenses has not been determined but could be material. The adoption of EITF 03-11 will have no impact on net income.

As discussed above, FIN No. 46 was effective for Exelon's variable interest entities created after January 31, 2003 and FIN No. 46-R was effective December 31, 2003 for Exelon's other variable interest entities that are considered to be special-purpose entities. FIN No. 46-R applies to all other variable interest entities as of March 31, 2004. Exelon believes that it is reasonably possible that it will consolidate Sithe as of March 31, 2004. Generation is a 50% owner of Sithe and accounts for this entity as an unconsolidated equity investment. Sithe owns and operates power generating facilities. Generation contractually does not own any interest in Sithe International, a subsidiary of Sithe. As such, a portion of Sithe's net assets and results of operations would be eliminated from Generation's Consolidated Balance Sheets and Consolidated Statements of Income through a minority interest if Sithe is consolidated under FIN No. 46-R as of March 31, 2004. See Note 3—Sithe for a further discussion of Generation's investment in Sithe. Exelon continues to review other entities with which Exelon and its subsidiaries have business arrangements to determine if those entities are variable interest entities under FIN No. 46-R and, if so, whether consolidation of these entities will be required as of March 31, 2004.

NOTE 02 • ACQUISITIONS AND DISPOSITIONS

AmerGen Energy Company, LLC

On December 22, 2003, Generation purchased British Energy plc's (British Energy) 50% interest in AmerGen for $276.5 million.

Prior to the purchase, Generation was a 50% owner of AmerGen and had accounted for the investment as an unconsolidated equity investment. From January 1, 2003 through the date of closing, Generation recorded $47 million of equity in earnings of unconsolidated affiliates related to its investment in AmerGen and had significant purchased power agreements (PPAs) with AmerGen. The book value of Generation's investment in AmerGen prior to the purchase was $311 million.

The transaction was accounted for as a step acquisition. As such, upon consolidation, Generation was required to allocate its $311 million book value as discussed above to 50% of AmerGen's equity balance. The difference between Generation's investment in AmerGen and 50% of AmerGen's equity book value of approximately $227 million was primarily due to Generation not recognizing a significant portion of the cumulative effect of the change in accounting principle at AmerGen related to the adoption of SFAS No. 143. Generation reduced AmerGen's equity value through the reduction of the book value of AmerGen's long-lived assets.

Exelon recorded the acquired assets and liabilities of AmerGen (remaining 50%) to fair value as of the date of purchase. The following assets and liabilities, reflecting the equity basis and fair value adjustments discussed above, of AmerGen were recorded within Exelon's Consolidated Balance Sheets as of the date of purchase:

Current assets (including $36 million of cash acquired)	$ 128
Property, plant and equipment, including nuclear fuel	129
Nuclear decommissioning trust funds	1,108
Deferred debits and other assets	31
Current liabilities	(174)
Asset retirement obligation	(487)
Deferred credits and other liabilities	(106)
Long-term debt	(41)
Total equity	$ 588

As of December 31, 2003, the assets and liabilities of AmerGen were fully consolidated into Exelon's financial statements. The above allocation of purchase price is preliminary related to the valuation of long-lived assets, which will be finalized in early 2004.

Exelon New England Holdings Asset Acquisition

On November 1, 2002, Generation purchased the assets of Sithe New England Holdings, LLC (now known as Exelon New England), a subsidiary of Sithe, and related power marketing operations with a total of 4,066 megawatts of capacity. Exelon New England's primary assets were gas-fired generating facilities under construction. The purchase price for the Exelon New England assets consisted of a $536 million note to Sithe, $14 million of direct acquisition costs and a $208 million adjustment to Generation's previously existing investment in Sithe related to Exelon New England.

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

Current assets (including $12 million of cash acquired)	$ 85
Property, plant and equipment	1,949
Deferred debits and other assets	63
Current liabilities	(154)
Deferred credits and other liabilities	(149)
Long-term debt	(1,036)
Total purchase price	$ 758

In connection with the acquisition, Generation assumed certain Sithe guarantees, including a guarantee of a contingent equity contribution to be made to Sithe Boston Generating, LLC (currently known as Boston Generating), a project subsidiary of Exelon New England. Exelon New England made a contribution of $38 million to Boston Generating in full satisfaction of that contingent equity contribution guarantee in December 2003.

Boston Generating has a $1.25 billion credit facility (Boston Generating Facility), which was entered into primarily to finance the development and construction of generating projects known as Mystic 8 and 9 and Fore River. Approximately $1.0 billion of debt was outstanding under the Boston Generating Facility at December 31, 2003, all of which is reflected in Exelon's Consolidated Balance Sheets as a current liability due to certain events of default described below. The Boston Generating Facility is non-recourse to Exelon and an event of default under the Boston Generating Facility does not constitute an event of default under any other debt instruments of Exelon or its subsidiaries.

The Boston Generating Facility required that all of the projects achieve "Project Completion," as defined in the Boston Generating Facility (Project Completion), by July 12, 2003. Project Completion was not achieved by July 12, 2003, resulting in an event of default under the Boston Generating Facility. Mystic 8 and 9 and Fore River have all begun commercial operation, although they have not yet achieved Project Completion.

As a result of Generation's continuing evaluation of the projects and discussions with the lenders, in July 2003, Generation commenced the process of an orderly transition out of the ownership of Boston Generating and the projects. The transition out of Generation's ownership of Boston Generating will take place in a manner that complies with applicable regulatory requirements. For a period of time, Generation expects to continue to provide administrative and operational services to Boston Generating in its operation of the projects. Generation informed the lenders of its decision to exit and that it will not provide additional funding beyond its existing contractual obligations. Generation anticipates that this transition will occur in 2004.

As a result of the decision to transition out of the ownership of Boston Generating and the projects in the third quarter of 2003, Generation recorded an impairment charge related to Boston Generating's long-lived assets pursuant to SFAS No. 144 of $945 million ($573 million net of income taxes). In determining the amount of the impairment charge, management compared the carrying value of Boston Generating's long-lived assets to the fair value of those assets. Because comparable asset sale data was not available, the fair value of Boston Generating's long-lived assets was determined using the estimated future discounted cash flows from those assets. Forecasted cash flows incorporated assumptions relative to the period of time that Generation will continue to own and operate Boston Generating.

Acquisition of Generating Plants from TXU

On April 25, 2002, Generation acquired two natural-gas generation plants with a total of 2,334 megawatts of capacity from TXU Corp. (TXU) for an aggregate purchase price of $443 million. 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 makes fixed capacity payments, variable expense payments, and provides fuel to Exelon in return for exclusive rights to the energy and capacity of the generation plants. Substantially the entire purchase price was allocated to property, plant and equipment.

InfraSource

On September 24, 2003, Enterprises sold the electric construction and services, underground and telecom businesses of InfraSource. Cash proceeds to Enterprises from the sale were approximately $175 million, net of transaction costs and cash transferred to the buyer upon sale, plus a $30 million subordinated note receivable maturing in 2011. At the time of closing, the present value of the note receivable was approximately $12 million. In connection with the transaction, Enterprises entered into an agreement that may result in certain payments to InfraSource if the amount of services Exelon purchases from InfraSource during the period from closing through 2006 is below specified thresholds. Pursuant to the sales agreement, certain working capital adjustments to the purchase price will be made in 2004.

In connection with the above agreement, Enterprises recorded an impairment charge during the second quarter of 2003 of approximately $48 million (before income taxes and minority interest) pursuant to SFAS No. 142 related to the goodwill recorded within the InfraSource reporting unit. Management of Enterprises primarily considered the negotiated sales price and the estimated book value of InfraSource at the time of the closing of the sale in determining the amount of the goodwill impairment charge. In connection with the closing of the sale in the third quarter of 2003, Enterprises recorded a gain of $44 million (before income taxes), primarily due to the book value of InfraSource at the date of closing being lower than estimated in the second quarter of 2003. The net impact of the goodwill impairment in the second quarter and the gain recorded in the third quarter was a loss before income taxes and minority interest of $4 million for the year ended December 31, 2003. The net impact was recorded as an operating and maintenance expense within the Consolidated Statements of Income.

Exelon Thermal Holdings, Inc.

In December 2003, Exelon signed an agreement to sell its Chicago thermal business of Exelon Thermal Holdings, Inc. (Thermal) for approximately $135 million, subject to working capital adjustments. The agreement to sell the Chicago thermal operations is subject to customary closing conditions and approval from the City of Chicago (Chicago) and is expected to close during the first half of 2004. The debt of the Chicago thermal operations is required to be repaid by Enterprises prior to closing. The total debt outstanding of the Chicago thermal operations as of December 31, 2003 was $38 million, which may result in prepayment penalties. Exelon also reached agreement to sell Exelon's 75% share in the Aladdin thermal facility (located in Las Vegas, Nevada) for $24 million, which is contingent upon the exit of the Aladdin Hotel, the primary customer, from bankruptcy. The sale is expected to close during the second half of 2004. In 2003, Enterprises recorded an impairment charge of $8 million (before income taxes) related to its investment in the Aladdin thermal facility based on the terms of the sales agreement. See Assets and Liabilities Held for Sale below for discussion of the classification of the Thermal assets and liabilities as of December 31, 2003.

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. Exelon recorded a gain of $116 million (net of income taxes) on the $84 million investment in other income and deductions on its Consolidated Statements of Income.

Assets and Liabilities Held for Sale

As of December 31, 2003, the assets and liabilities of certain entities of Thermal and Exelon Services, Inc. (Exelon Services) were classified as held for sale within the Consolidated Balance Sheet pursuant to SFAS No. 144. Enterprises recognized impairment charges totaling $14 million (before income taxes) under SFAS No. 144 related to the assets of Exelon Services that were classified as held for sale as of December 31, 2003. These assets and liabilities are reported under the Enterprises segment in Note 21—Segment Information and are expected to be sold in 2004. See Note 8—Goodwill for information regarding the goodwill impairment charge recorded in 2003 related to Exelon Services.

Generation classified three gas turbines with a book value of $36 million as held for sale as of December 31, 2003 in anticipation of their sale in 2004. These turbines had been classified as other long-term assets as they were not placed into service. The major classes of assets and liabilities classified as held for sale as of December 31, 2003 consist of the following (in millions):

	Generation	Thermal	Exelon Services	Total
Cash	$ –	$ 9	$ 2	$ 11
Accounts receivable, net	–	13	46	59
Other current assets	–	1	23	24
Property, plant and equipment, net	–	85	1	86
Other long-term assets	36	12	14	62
Total assets classified as held for sale	$36	$120	$86	$242

	Thermal	Exelon Services	Total
Accounts payable, accrued expenses and other current liabilities	$ 4	$40	$44
Debt	1	–	1
Asset retirement obligation	3	–	3
Other long-term liabilities	10	3	13
Total liabilities classified as held for sale	$18	$ 43	$ 61

Synthetic Fuel-Producing Facilities

In November 2003, Exelon purchased interests in two synthetic fuel-producing facilities. Exelon's purchase price for these facilities included a combination of cash, notes payable and contingent consideration dependent upon the production level of the facilities. These facilities are not consolidated within Exelon's financial statements as Exelon does not have the ability to exert a significant influence on these facilities. The notes payable recorded for the purchase of the facilities was $238 million. Exelon's right to acquire its share of tax credits generated by the facilities was recorded as an intangible asset and will be amortized as the tax credits are earned. Synthetic fuel facilities chemically change coal, including waste and marginal coal, into a fuel used at power plants. Requests for two private letter rulings have been filed with the Internal Revenue Service (IRS) to affirm that the fuel production from these facilities qualifies for tax credits under Section 29 of the Internal Revenue Code. Exelon has retained a termination right that may be exercised in the event that the letter rulings are not received within one year.

NOTE 03 • SITHE

Generation is a 50% owner of Sithe and accounts for the investment as an unconsolidated equity investment. In 2003, Generation recorded impairment charges of $255 million (before income taxes) in other income and deductions within the Consolidated Statements of Income associated with a decline in the fair value of the Sithe investment, which was considered to be other-than-temporary. Generation's management considered various factors in the decision to impair this investment, including management's negotiations to sell its interest in Sithe. The discussions surrounding the sale indicated that the fair value of the Sithe investment was below its book value and, as such, impairment charges were required.

On November 25, 2003, Generation, Reservoir Capital Group (Reservoir) and Sithe completed a series of transactions resulting in Generation and Reservoir each indirectly owning a 50% interest in Sithe. This series of transactions is described below. Immediately prior to these transactions, Sithe was owned 49.9% by Generation, 35.2% by Apollo Energy, LLC (Apollo), and 14.9% by subsidiaries of Marubeni Corporation (Marubeni).

On November 25, 2003, entities controlled by Reservoir purchased certain Sithe entities holding six U.S. generating facilities, each a qualifying facility under the Public Utility Regulatory Policies Act, in exchange for $37 million ($21 million in cash and a $16 million two-year note); and entities controlled by Marubeni purchased all of Sithe's entities and facilities outside of North America (other than Sithe Energies Australia (SEA) of which it purchased a 49% interest on November 24, 2003 for separate consideration) for $178 million. Marubeni agreed to acquire the remaining 51% of SEA in 90 days if a buyer is not found, although discussions regarding an extension are ongoing.

Following the sales of the above entities, Generation transferred its wholly owned subsidiary that held the Sithe investment to a newly formed holding company. The subsidiary holding the Sithe investment acquired the remaining Sithe interests from Apollo and Marubeni for $612 million using proceeds from a $580 million bridge financing and available cash. Generation sold a 50% interest in the newly formed holding company for $76 million to an entity controlled by Reservoir on November 25, 2003. On November 26, 2003, Sithe distributed $580 million of available cash to its parent, which then utilized the distributed funds to repay the bridge financing.

In connection with this transaction, Generation recorded obligations related to $39 million of guarantees in accordance with FASB Interpretation (FIN) No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness to Others" (FIN No. 45). These guarantees were issued to protect Reservoir from credit exposure of certain counterparties through 2015 and other indemnities. In determining the value of the FIN No. 45 guarantees, Exelon utilized probabilistic models to assess the possibilities of future payments under the guarantees.

Both Generation and Reservoir's 50% interests in Sithe are subject to put and call options that could result in either party owning 100% of Sithe. While Generation's intent is to fully divest Sithe, the timing of the put and call options vary by acquirer and can extend through March 2006. The pricing of the put and call options is dependent on numerous factors, such as the acquirer, date of acquisition and assets owned by Sithe at the time of exercise. Any closing under either the put or call options is conditioned upon obtaining state and Federal regulatory approvals.

At December 31, 2003, Sithe had total assets of $1.5 billion (including the $90 million note from Generation) and total liabilities of $1.6 billion. Of the total liabilities, Sithe had $1.0 billion of debt which included $588 million of subsidiary debt incurred in prior years, primarily to finance the construction of six generating facilities, $419 million of subordinated debt, $43 million of current portion of long-term debt, but excludes $469 million of non-recourse debt associated with Sithe's equity investments. For the year ended December 31, 2003, Sithe had revenues of $690 million and incurred a net loss of approximately $72 million. Exelon contractually does not own any interest in Sithe International, a subsidiary of Sithe.

The book value of Generation's investment in Sithe was $47 million at December 31, 2003. Generation recorded $2 million of equity method income for its investment in Sithe during the twelve months ended December 31, 2003. See Note 1—Significant Accounting Policies for a discussion of Sithe in relation to FIN No. 46-R.

NOTE 04 • REGULATORY ISSUES

ComEd

Delivery Service Rates. On March 3, 2003, ComEd entered into and the ICC subsequently entered orders to implement, an agreement (Agreement) with various Illinois retail market participants and other interested parties that settled, among other things, delivery service rates and the market value index proceeding and facilitates competitive service declarations for large-load customers and an extension of the PPA with Generation. The effect of the Agreement is lower competitive transition charge (CTC) collections that ComEd charges customers who take electricity from an alternative retail electric supplier (ARES) or under the purchase power option (PPO) through 2006. The Agreement also allows customers to lock in current CTC charges for multiple years. A non-party to the Agreement has appealed one of the ICC's orders which, if ultimately successful, may impact the Agreement on a going-forward basis.

The annual market price adjustments to the CTC effective in June 2002 and the impacts of the Agreement in June 2003 had the effect of significantly increasing the CTC charge in June 2002, and subsequently significantly reducing the CTC charge in June 2003. In 2003 and 2002, ComEd collected $304 million and $306 million in CTC revenues, respectively. Based on the changes in the CTC as part of the Agreement and on current assumptions about the competitive price of delivered energy and customers' choice of electric supplier, ComEd estimates that CTC revenue will be approximately $180 million to $200 million in each of the years 2004 through 2006.

In 2003, ComEd recorded a charge to earnings associated with the required funding of specified programs and initiatives associated with the Agreement of $51 million (before income taxes) on a present value basis. This amount was partially offset by the reversal of a $12 million (before income taxes) reserve established in the third quarter of 2002 for a potential capital disallowance in ComEd's delivery services rate proceeding and a credit of $10 million (before income taxes) related to the capitalization of employee incentive payments provided for in the delivery services order. The charge of $51 million and the credit of $10 million were recorded in operating and maintenance expense and the reversal of the $12 million reserve was recorded in other, net within Exelon's Consolidated Statements of Income. The net charge for these items was $29 million (before income taxes). In accordance with the Agreement, ComEd made payments of $23 million during 2003.

Customer Choice. All of ComEd's retail customers are eligible to choose an ARES and non-residential customers may also buy electricity from ComEd at market-based prices under the PPO. No alternative provider has chosen to serve ComEd's residential customers. As of December 31, 2003, about 20,300 non-residential customers, or 31% of ComEd's annual retail kilowatthour sales, had elected either the PPO or an ARES. Customers who receive energy from an alternative supplier continue to pay a delivery charge.

Customer Service Declarations. On November 14, 2002, the ICC allowed ComEd, by operation of law, to revise its provider of last resort obligation to be the back-up energy supplier at market-based rates for customers with energy demands of at least three megawatts. About 370 of ComEd's largest energy customers are affected, representing an aggregate supply obligation or load of approximately 2,500 megawatts. These customers accounted for 10% of ComEd's 2003 MWh deliveries. These customers will not have a right to take bundled service after June 2006 or to come back to bundled rates if they choose an alternative supplier. The parties to the Agreement have committed, if specified market conditions exist, not to oppose a process to be initiated in June 2004 or thereafter for achieving a similar competitive declaration for customers having energy demands of one to three megawatts.

On March 28, 2003, the ICC approved changes to ComEd's real-time pricing tariff, which would be made available to customers who choose not to go to the competitive market to procure their electric power and energy. An appeal to each of the ICC's orders is pending and ComEd cannot predict the outcome of those appeals.

Exelon cannot predict the long-term impact of customer choice on results of operations.

Rate Reductions and Return on Common Equity Threshold. The Illinois restructuring legislation as amended required a 15% residential base rate reduction effective August 1, 1998 and an additional 5% residential base rate reduction effective October 1, 2001. In addition, a base rate freeze, reflecting the residential base rate reduction, is in effect through January 1, 2007. A utility may request a rate increase during the rate freeze period only when necessary to ensure the utility's financial viability. Under the Illinois legislation, if the two-year average of the earned return on common equity of a utility through December 31, 2006 exceeds an established threshold, one-half of the excess earnings must be refunded to customers. The threshold rate of return on common equity is based on a two-year average of the Monthly Treasury Bond Long-Term Average Rates (25 years and above) plus 8.5% in the years 2000 through 2006. Earnings for purposes of ComEd's threshold include ComEd's net income calculated in accordance with GAAP and reflect the amortization of regulatory assets. As a result of the Illinois legislation, at December 31, 2003, ComEd had a regulatory asset with an unamortized balance of $131 million that it expects to fully recover and amortize by the end of 2006. ComEd did not trigger the earnings sharing provision in 2001, 2002 or 2003 and does not currently expect to trigger the earnings sharing provisions in the years 2004 through 2006.

Nuclear Decommissioning Costs. In connection with the transfer of ComEd's nuclear generating stations to Generation, the ICC permitted ComEd to recover $73 million per year from retail customers for decommissioning for the years 2001 through 2004 and, depending upon the portion of the output from those stations taken by ComEd, up to $73 million annually in 2005 and 2006. These amounts are remitted to Generation. Subsequent to 2006, there will be no further recoveries of decommissioning costs from customers. Any surplus funds after a nuclear station is decommissioned must be refunded to ComEd's customers. See Note 13—Nuclear Decommissioning and Spent Fuel Storage.

Open Access Transmission Tariff. On November 10, 2003, the FERC issued an order allowing ComEd to put into effect beginning April 12, 2004, subject to refund and rehearing, new transmission rates designed to reflect nearly $500 million of infrastructure investments made since 1998. However, because of the Illinois retail rate freeze and the method for calculating CTCs, the increase is not expected to significantly increase operating revenues. Exelon is unable to predict the ultimate outcome of the associated rehearing or settlement negotiations.

PECO

In 2003, the phased process to implement competition in the electric industry continued as mandated by the requirements of the PUC's Final Restructuring Order as further discussed below.

Rate limitations. PECO is subject to agreed-upon rate reductions of $80 million, in aggregate, for the years 2004 and 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, and on its energy rates through December 31, 2010, as a result of settlements previously reached with the PUC.

Nuclear Decommissioning Cost Adjustment Clause. On July 25, 2003, the PUC approved an adjustment to PECO's nuclear decommissioning cost adjustment clause. Effective January 1, 2004, PECO will be permitted to recover an additional $3.6 million annually, or $33 million compared to $29 million previously. These amounts are remitted by PECO to Generation upon collection.

Customer Choice. The 1998 Electric Restructuring Settlement approved by the PUC established market share thresholds (MST) to promote competition. The MST requirements provided that if, as of January 1, 2003, less than 50% of residential and commercial customers have chosen an alternative electric generation supplier, the number of customers sufficient to meet the MST shall be randomly selected and assigned to an alternative electric generation supplier through a PUC-determined process. On January 1, 2003, the number of customers choosing an alternative electric generation supplier did not meet the MST. As a result of a PUC-approved auction process, approximately 64,000 small commercial and industrial customers and 267,000 residential customers were selected to participate in the MST program of which approximately 50,000 and 194,000 customers enrolled with alternative electric generation suppliers in May 2003 and December 2003, respectively. Any customer transferred has the right to return to PECO at any time. Exelon does not expect the transfer of PECO customers pursuant to the MST plan to have a material impact on its results of operations, financial position or cash flows.

See Note 20—Supplemental Financial Information for further discussion of the regulatory assets and liabilities of ComEd and PECO.

NOTE 05 • ACCOUNTS RECEIVABLE

Customer accounts receivable at December 31, 2003 and 2002 included unbilled operating revenues related to unread meters at Energy Delivery and Exelon Energy Company, the competitive retail energy sales business of Enterprises, of $452 million and $442 million, respectively. Also included in customer accounts receivable was $366 million and $394 million at December 31, 2003 and 2002, respectively, related to Generation's unbilled revenues for amounts of energy delivered to customers in the month of December. The allowance for uncollectible accounts at December 31, 2003 and 2002 was $110 million and $132 million, respectively.

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. PECO performed a similar evaluation which resulted in changes to its accounting estimate processes related to the allowance for uncollectible accounts. As a result, the allowance for uncollectible accounts reserve was reduced by $17 million in the fourth quarter of 2002.

In December 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.

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, 2003, PECO had sold a $225 million interest in accounts receivable, consisting of a $176 million interest in accounts receivable which PECO accounted for as a sale under SFAS No. 140, "Accounting for Transfers and Servicing of Financial Assets and Extinguishment of Liabilities—a Replacement of FASB Statement No. 125," (SFAS No. 140) and a $49 million interest in special-agreement accounts receivable which was accounted for as a long-term note payable. 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 and a $61 million interest in special-agreement accounts receivable which was accounted for as a long-term note payable (see Note 11—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, 2003 and 2002, PECO met this requirement and was not required to make any cash deposits.

NOTE 06 • PROPERTY, PLANT, AND EQUIPMENT

A summary of property, plant and equipment by asset category as of December 31, 2003 and 2002 is as follows:

Asset Category	2003	2002
Electric–transmission and distribution	**$ 12,755**	$ 11,940
Electric–generation	**7,976**	5,678
Gas–transmission and distribution	**1,387**	1,319
Common	**376**	370
Nuclear fuel	**2,568**	3,114
Construction work in progress	**795**	2,772
Asset retirement cost	**173**	–
Other property, plant and equipment	**1,548**	1,644
Total property, plant and equipment	**27,578**	26,837
Less accumulated depreciation (including accumulated amortization of nuclear fuel of $1,596 and $2,212 as of December 31, 2003 and 2002, respectively)	**6,948**	8,880
Property, plant and equipment, net	**$20,630**	$ 17,957

Energy Delivery's depreciation expense, which is included in cost of service for rate purposes, includes an estimated cost of dismantling and removing plant from service upon retirement. Beginning in 2003, in accordance with regulatory accounting practice, collections for future removal costs are recorded as a regulatory liability. Prior periods have been reclassified for comparative purposes. For more information, see Note 20–Supplemental Financial Information.

In July 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 was $96 million.

In April 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. In July 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 the plants. The service life extensions are subject to Nuclear Regulatory Commission (NRC) approval of NRC operating licenses, which are generally 40 years. The annualized reduction in depreciation expense from the change is $132 million.

NOTE 07 • JOINTLY OWNED ELECTRIC UTILITY PLANT

Exelon's undivided ownership interests in jointly owned electric plant at December 31, 2003 and 2002 were as follows:

	Production Plant					
December 31, 2003	Peach Bottom	Salem	Keystone	Conemaugh	Quad Cities	Transmission
Operator	Generation	PSE&G	Reliant	Reliant	Generation	LDVT[(a)]
Ownership interest	50%	42.59%	20.99%	20.72%	75%	21%
Exelon's share:						
Plant	$ 449	$ 106	$ 167	$ 210	$ 193	$ 56
Accumulated depreciation	239	24	106	138	18	23
Construction work in progress	1	48	2	1	24	—

(a) Lower Delaware Valley Transmission System (LDVT).

	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.
Ownership interest	50%	42.59%	20.99%	20.72%	75%	21 to 44%
Exelon's share:						
Plant	$ 417	$ 44	$ 131	$ 214	$ 171	$ 58
Accumulated depreciation	229	12	98	127	4	22
Construction work in progress	52	36	28	1	35	–

Exelon's undivided ownership interests are financed with Exelon funds and 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 Statements of Income.

NOTE 08 • GOODWILL

Adoption of SFAS No. 142

Effective January 1, 2002, Exelon adopted SFAS No. 142. Pursuant to SFAS No. 142, goodwill is no longer amortized; however, in addition to an initial assessment, goodwill is subject to an assessment for impairment at least annually, or more frequently, if events or circumstances indicate that goodwill might be impaired. The impairment assessment is performed using a two-step, fair-value based test. The first step compares the fair value of the reporting unit to its carrying amount, including goodwill. If the carrying amount of the reporting unit exceeds its fair value, the second step is performed. The second step compares the carrying amount of the goodwill to the estimated fair value of the goodwill. If the fair value of goodwill is less than the carrying amount, an impairment loss is reported as a reduction to goodwill and a charge to operating expense.

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 goodwill, net of accumulated amortization, 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 Energy Delivery's goodwill was not impaired but that an impairment did exist with respect to goodwill recorded in Enterprises' reporting units. InfraSource, Exelon Services and Exelon Energy Company 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 components of the net transitional impairment loss recognized in the first quarter of 2002 as a cumulative effect of a change in accounting principle were 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)

Accounting Methodology Under SFAS No. 142

The changes in the carrying amount of goodwill by reportable segment (see Note 21—Segment Information) for the years ended December 31, 2002 and 2003 were as follows:

	Energy Delivery	Enterprises	Total
Balances 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)
Balances as of January 1, 2003	4,916	76	4,992
Impairment losses	–	(72)	(72)
Adoption of SFAS No. 143:[a]			
Reduction of asset retirement obligation	(210)	–	(210)
Cumulative effect of change in accounting principle	5	–	5
Resolution of certain tax matters	8	–	8
Other	–	(4)	(4)
Balances as of December 31, 2003	$ 4,719	$ –	$ 4,719

(a) See Note 13–Nuclear Decommissioning and Spent Fuel Storage.

As described below, Exelon recorded charges of $72 million (before income taxes) during 2003 to fully impair the goodwill that had been recorded within the Exelon Services and InfraSource reporting units of the Enterprises segment.

In connection with the sale of InfraSource in 2003, Exelon recorded a goodwill impairment charge of approximately $48 million related to the goodwill recorded by the InfraSource. Management of Exelon primarily considered the negotiated sales price of InfraSource in determining the amount of the goodwill impairment charge.

The annual goodwill impairment assessment was performed as of November 1, 2003 and Exelon determined that goodwill was not impaired at Energy Delivery, but that the remaining goodwill at Exelon Services was fully impaired. In its assessments to estimate the fair value of the Energy Delivery reporting unit, Exelon used a probability-weighted, discounted cash flow model with multiple scenarios. The determination of the fair value is dependent on many sensitive, interrelated and uncertain variables including changing interest rates, utility sector market performance, ComEd's capital structure, market power prices, post-2006 rate regulatory structures, operating and capital expenditure requirements and other factors. Current negotiations regarding the sale of Exelon Services served as the basis for the fair value of the Exelon Services reporting unit used in the first step of the analysis.

The first step of the annual impairment analysis, comparing the fair value of a reporting unit to its carrying value, including goodwill, indicated no impairment of Energy Delivery's goodwill but showed an impairment of the goodwill within the Exelon Services reporting unit. The second step of the analysis, which compared the fair value of the Exelon Services reporting unit's goodwill to the carrying value, indicated that the total goodwill recorded at the Exelon Services reporting unit of $24 million was impaired.

Exelon recorded the 2003 goodwill impairment charges related to the InfraSource and Exelon Services reporting units as operating and maintenance expenses within the Consolidated Statements of Income.

Changes from the assumptions used in the impairment review could possibly result in a future impairment loss of Energy Delivery's goodwill. Illinois legislation provides that reductions to ComEd's common equity resulting from goodwill impairments will have no impact on the determination of the rate cap on ComEd's allowed equity return during the electricity industry restructuring transition period through 2006. See Note 4—Regulatory Issues for further discussion of ComEd's earnings provisions.

NOTE 09 • SEVERANCE ACCOUNTING

Exelon provides severance and health and welfare benefits to terminated employees pursuant to pre-existing severance plans primarily based upon each individual employee's years of service with Exelon and compensation level. Exelon accounts for its ongoing severance plans in accordance with SFAS No. 112, "Employer's Accounting for Postemployment Benefits, an amendment of FASB Statements No. 5 and 43" (SFAS No. 112) and SFAS No. 88, "Employers' Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits" and accrues amounts associated with severance benefits that are considered probable and that can be reasonably estimated.

As part of the implementation of Exelon's new business model referred to as The Exelon Way during 2003, Exelon identified approximately 1,500 positions for elimination by the end of 2004. The majority of the headcount reductions are professional and managerial employees. Exelon recorded a charge for salary continuance severance of $130 million (before income taxes) associated with The Exelon Way during 2003, which represented salary continuance costs that were probable and could be reasonably estimated as of December 31, 2003. During 2003, Exelon recorded a charge of $48 million (before income taxes) associated with special health and welfare severance benefits offered through The Exelon Way. In addition to salary continuance and health and welfare severance benefits, Exelon incurred curtailment costs associated with its pension and postretirement benefit plans of $80 million as a result of personnel reductions due to The Exelon Way. In total, Exelon recorded charges of $258 million (before income taxes) in 2003 associated with The Exelon Way. See Note 14 – Retirement Benefits for a description of the curtailment charges related to the pension and postretirement benefit plans.

Exelon based its estimate of the number of positions to be eliminated on management's current plans and its ability to determine the appropriate staffing levels to effectively operate the businesses. Exelon may incur further severance costs associated with The Exelon Way if additional positions are identified for elimination. These costs will be recorded in the period in which the costs can be first reasonably estimated.

The following table details, by segment, Exelon's total salary continuance severance costs for the years ended December 31, 2003, 2002 and 2001:

Salary continuance severance charges	Energy Delivery	Generation	Enterprises	Corporate and Intersegment Eliminations	Consolidated
Costs recorded–2003[(a)]	**$77**	**$38**	**$9**	**$ 11**	**$135**
Costs recorded–2002[(b)]	–	2	(1)	7	8
Costs recorded–2001[(b)]	–	4	9	(6)	7

(a) Severance expense in 2003 reflects severance costs associated with The Exelon Way and other severance costs incurred in the normal course of business.
(b) Severance expense in 2002 and 2001 generally represents severance activity associated with the Merger and in the normal course of business.

The following table provides a roll forward of Exelon's salary continuance severance obligation from January 1, 2002 through December 31, 2003. The salary continuance severance obligation as of January 1, 2002 and amounts paid in 2002 relate to severance associated with the Merger.

Salary continuance severance obligation	
Balance as of January 1, 2002	$124
Severance charges recorded	8
Cash payments	(78)
Other adjustments	(15)
Balance as of January 1, 2003	39
Severance charges recorded	135
Cash payments	(39)
Other adjustments	4
Balance as of December 31, 2003	$139

NOTE 10 • NOTES PAYABLE AND SHORT-TERM DEBT

Commercial Paper and Credit Facility

	2003	2002	2001
Average borrowings	**$144**	$337	$193
Maximum borrowings outstanding	**1,288**	783	599
Average interest rates, computed on daily basis	**1.25%**	1.94%	4.01%
Average interest rates, at December 31	**1.08%**	1.88%	2.63%

In October 2003, Exelon, ComEd, PECO and Generation replaced their $1.5 billion bank unsecured revolving credit facility with a $750 million 364-day unsecured revolving credit agreement and a $750 million three-year unsecured revolving credit agreement with a group of banks. Both revolving credit agreements are used principally to support the commercial paper programs at Exelon, ComEd, PECO and Generation and to issue letters of credit. The 364-day agreement also includes a term-out option provision that allows a borrower to extend the maturity of revolving credit borrowings outstanding at the end of the 364-day period for one year.

At December 31, 2003, aggregate sublimits under the credit agreements were $1.0 billion, $100 million, $150 million and $250 million for Exelon Corporate, ComEd, PECO, and Generation, respectively. Sublimits under the credit agreements can change upon written notification to the bank group. Exelon Corporate, ComEd, PECO and Generation had approximately $955 million, $80 million, $148 million and $170 million of unused bank commitments under the credit agreements, respectively, at December 31, 2003. At December 31, 2003, commercial paper outstanding was $280 million and $46 million at Exelon Corporate and PECO, respectively. ComEd and Generation did not have any commercial paper outstanding at December 31, 2003. Interest rates on the advances under the credit facility are based on either the London Interbank Offering Rate (LIBOR) or prime plus an adder based on the credit rating of the borrower as well as the total outstanding amounts under the agreement at the time of borrowing. The maximum adder would be 175 basis points.

Boston Generating Facility

Approximately $1.0 billion of debt was outstanding under the Boston Generating Facility at December 31, 2003, all of which was reflected in Exelon's Consolidated Balance Sheets as a current liability due to certain events of default described in Note 2—Acquisitions and Dispositions. The Boston Generating Facility is non-recourse to Exelon and an event of default under the Boston Generating Facility does not constitute an event of default under any other debt instruments of Exelon or its subsidiaries.

Generation Revolving Credit Facility

On September 29, 2003, Generation closed on an $850 million revolving credit facility that replaced a $550 million revolving credit facility that had originally closed on June 13, 2003. Generation used the facility to make the first payment to Sithe relating to the $536 million note that was used to purchase Exelon New England. This note was restructured in June 2003 to provide for a payment of $210 million of the principal on June 16, 2003, payment of $236 million of the principal on the earlier of December 1, 2003 or a change of control of Generation, and payment of the remaining principal on the earlier of December 1, 2004 or a change of control of Generation. Generation terminated the $850 million revolving credit facility on December 22, 2003.

NOTE 11 • LONG-TERM DEBT

	Rates	Maturity Date	December 31, 2003	2002
Securitized long-term debt[a]				
ComEd Transitional Trust Notes Series 1998-A:			$ –	$ 2,040
PETT Bonds Series 1999-A:				
Fixed rates			–	2,426
Floating rates			–	274
PETT Bonds Series 2000-A:			–	750
PETT Bonds Series 2001:			–	805
Other long-term debt				
First and Refunding Mortgage Bonds[b][c]:				
Fixed rates	3.50%-9.875%	2004-2033	4,312	3,614
Floating rates	1.07%-1.30%	2012-2020	406	254
Notes payable and other	5.35%-9.20%	2004-2020	2,944	2,393
Boston Generating Facility	6.60%[d]	2007	1,037	1,036
Pollution control notes:				
Fixed rates	5.20%-5.30%	2021-2034	156	199
Floating rates	0.95%-1.15%	2016-2034	363	456
Notes payable–accounts receivable agreement	1.40%	2005	49	61
Sinking fund debentures	3.125%-4.75%	2004-2011	17	20
Commercial paper[e]			–	267
Total long-term debt[f]			9,284	14,595
Unamortized debt discount and premium, net			(43)	(107)
Fair-value hedge carrying value adjustment, net			33	41
Long-term debt due within one year			(1,385)	(1,402)
Long-term debt			$ 7,889	$ 13,127
Long-term debt to financing trusts[a]				
Subordinated debentures to ComEd Financing II	8.50%	2027	$ 155	$ –
Subordinated debentures to ComEd Financing III	6.35%	2033	206	–
Subordinated debentures to PECO Trust III	7.38%	2028	81	–
Subordinated debentures to PECO Trust IV	5.75%	2033	103	–
Payable to ComEd Transitional Funding Trust	5.44%-5.74%	2004-2008	1,676	–
Payable to PETT	5.63%-7.65%	2004-2010	3,849	–
Long-term debt to financing trusts[g]			6,070	–
Long-term debt to financing trusts due within one year			(470)	–
Total long-term debt to financing trusts			$ 5,600	$ –

(a) Effective July 1, 2003, PECO Energy Capital Trust IV (PECO Trust IV), a financing subsidiary created in May 2003, was deconsolidated from the financial statements in conjunction with the adoption of FIN No. 46. Effective December 31, 2003, ComEd Financing II, ComEd Financing III, ComEd Transitional Funding Trust, PECO Trust III, and PETT were deconsolidated from the financial statements in conjunction with the adoption of FIN No. 46-R. Amounts owed to these financing trusts are recorded as debt to financing trusts within the Consolidated Balance Sheets. See Note 16—Preferred Securities for additional information regarding ComEd Financing II, ComEd Financing III, ComEd Funding LLC, PECO Trust III and PECO Trust IV.
(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 Boston Generating Facility is stated as an average rate. Under the terms of the Boston Generating Facility, Boston Generating is required to effectively fix the interest rate on 50% of the borrowings under the facility through its maturity in 2007. The Boston Generating Facility is subject to a variable rate based on the LIBOR rate plus a margin of 1.65% as of February 2003; however, through the required interest-rate swaps, Boston Generating had effectively fixed the LIBOR component of the interest rate at 5.73% on 83% of the debt balance as of December 31, 2003.
(e) Classified as long-term at December 31, 2002 since it was refinanced with long-term debt in January 2003.
(f) Long-term debt maturities in the period 2004 through 2008 and thereafter are as follows:

2004	$ 1,385
2005	657
2006	501
2007	232
2008	975
Thereafter	5,534
Total	$9,284

(g) Long-term debt to financing trusts maturities in the period 2004 through 2008 and thereafter are as follows:

2004	$ 470
2005	774
2006	855
2007	985
2008	965
Thereafter	2,021
Total	$6,070

During 2003, the following long-term debt was issued:

Company	Type	Rate	Maturity	Amount
ComEd	First Mortgage Bonds	4.70%	April 15, 2015	$ 395
ComEd	First Mortgage Bonds	3.70%	February 1, 2008	350
ComEd	First Mortgage Bonds	5.875%	February 1, 2033	350
ComEd	First Mortgage Bonds	4.74%	August 15, 2010	250
ComEd	Pollution Control Revenue Bonds[a]	Variable	November 1, 2019	42
ComEd	Pollution Control Revenue Bonds[a]	Variable	May 15, 2017	40
ComEd	Pollution Control Revenue Bonds[a]	Variable	March 1, 2020	50
ComEd	Pollution Control Revenue Bonds[a][b]	Variable	January 15, 2014	20
PECO	First Mortgage Bonds	3.50%	May 1, 2008	450
PECO	Long-term debt to financing trust–PECO Energy Capital Trust IV	5.75%	June 15, 2033	103
Generation	Pollution Control Revenue Bonds	Variable	June 1, 2027	17
Generation	Senior Notes	5.35%	January 15, 2014	500
Total issuances				$2,567

(a) These pollution control bonds are collateralized by first mortgage bonds issued under ComEd's mortgage indenture.
(b) As of December 31, 2003, the proceeds from the issuance of these pollution control revenue bonds were held in escrow for the redemption of pollution control revenue bonds in January 2004. The proceeds are included in restricted cash in Exelon's Consolidated Balance Sheets.

During 2003, the following long-term debt was retired or redeemed:

Company	Type	Rate	Maturity	Amount
ComEd	First Mortgage Bonds	8.375%	February 15, 2023	$ 236
ComEd	First Mortgage Bonds	8.00%	April 15, 2023	160
ComEd	First Mortgage Bonds	7.75%	July 15, 2023	150
ComEd	First Mortgage Bonds	6.625%	July 15, 2003	100
ComEd	Pollution Control Revenue Bonds	5.875%	May 15, 2007	42
ComEd	Pollution Control Revenue Bonds	Variable	October 15, 2014	42
ComEd	Pollution Control Revenue Bonds	Variable	March 1, 2009	50
ComEd	Medium Term Notes	Variable	September 30, 2003	250
PECO	First Mortgage Bonds	6.625%	March 1, 2003	250
PECO	First Mortgage Bonds	6.50%	May 1, 2003	200
PECO	Pollution Control Revenue Bonds	Variable	June 1, 2027	17
Total retirements and redemptions				$1,497

During 2003, Exelon retired $267 million of commercial paper classified as long-term debt.

During 2003, ComEd made payments of $340 million on the ComEd Transitional Funding Trust Notes, and PECO made payments of $239 million related to its obligation to the PETT. ComEd prepayment premiums of $21 million and $24 million and net unamortized premiums, discounts and debt issuance expenses of $38 million and $3 million associated with the early retirement of debt in 2003 and 2002, 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.

See Note 15—Fair Value of Financial Assets and Liabilities for additional information regarding interest-rate swaps of ComEd, PECO and Generation.

See Note 16—Preferred Securities for additional information regarding mandatorily redeemable preferred securities and preferred stock.

NOTE 12 • INCOME TAXES

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

	For the Years Ended December 31, 2003	2002	2001
Included in operations:			
Federal			
Current	**$ 576**	$624	$880
Deferred	**(238)**	250	(61)
Investment tax credit amortization	**(13)**	(15)	(14)
State			
Current	**92**	96	119
Deferred	**(86)**	43	7
	$ 331	$998	$ 931
Included in cumulative effect of changes in accounting principles:			
Deferred			
Federal	**$ 58**	$ (87)	$ 6
State	**11**	(3)	2
	$ 69	$ (90)	$ 8

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

	For the Years Ended December 31, 2003	2002	2001
U.S. Federal statutory rate	**35.0%**	35.0%	35.0%
Increase (decrease) due to:			
Synthetic fuel producing facilities credit	**(2.0)**	–	–
Low income housing credit	**(1.2)**	(0.5)	(0.5)
Plant basis differences	**(0.9)**	(0.4)	(0.2)
Amortization of investment tax credit	**(0.9)**	(0.4)	(0.5)
Tax exempt income	**(0.7)**	(0.2)	–
State income taxes, net of Federal income tax benefit	**0.4**	3.2	3.4
Amortization of goodwill	**–**	–	1.9
Other, net	**(0.3)**	0.7	0.6
Effective income tax rate	**29.4%**	37.4%	39.7%

The tax effects of temporary differences giving rise to significant portions of Exelon's deferred tax assets and liabilities as of December 31, 2003 and 2002 are presented below:

	2003	2002
Deferred tax liabilities:		
Plant basis difference	**$ 3,932**	$ 3,647
Stranded cost recovery	**1,784**	1,923
Deferred investment tax credits	**288**	301
Deferred debt refinancing costs	**69**	96
Total deferred tax liabilities	**6,073**	5,967
Deferred tax assets:		
Deferred pension and postretirement obligations	**(901)**	(911)
Excess of tax value over book value of impaired assets[a]	**(501)**	–
Decommissioning and decontamination obligations	**(97)**	(607)
Unrealized loss on derivative financial instruments	**(70)**	(60)
Goodwill	**(29)**	(95)
Other, net	**(304)**	(297)
Total deferred tax assets	**(1,902)**	(1,970)
Deferred income tax liabilities (net) on the Consolidated Balance Sheets	**$ 4,171**	$ 3,997

(a) Includes impairments related to Exelon's investments in Sithe and Boston Generating and write-downs of certain Enterprises investments.

In accordance with regulatory treatment of certain temporary differences, Exelon has recorded a net regulatory asset associated with deferred income taxes, pursuant to SFAS No. 71 and SFAS No. 109, "Accounting for Income Taxes," (SFAS No. 109) of $701 million and $661 million at December 31, 2003 and 2002, respectively. See Note 20 - Supplemental Financial Information for further discussion of Exelon's regulatory asset associated with deferred income taxes.

ComEd and PECO have certain tax returns that are under review at the audit or appeals level of the IRS and certain state authorities. These reviews by the governmental taxing authorities are not expected to have an adverse impact on the financial condition or result of operations of 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, 2003 and 2002, a deferred tax liability of approximately $848 million and $860 million, respectively, 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 expected to be under IRS audit beginning in 2004. Final resolution of this matter is not anticipated for several years.

As of December 31, 2003 and 2002, Exelon had recorded valuation allowances of $22 million and $13 million, respectively, with respect to deferred taxes associated with separate company state taxes.

NOTE 13 • NUCLEAR DECOMMISSIONING AND SPENT FUEL STORAGE

Nuclear Decommissioning

Exelon has an obligation to decommission its nuclear power plants. Based on the extended license lives of the nuclear plants, expenditures are expected to occur primarily during the period 2029 through 2056. Exelon currently recovers costs for decommissioning its nuclear generating stations, excluding the AmerGen stations, through regulated rates. See further discussion of AmerGen below. The amounts recovered from customers are deposited in trust accounts and invested for funding of future decommissioning costs of nuclear generating stations.

Exelon had decommissioning assets in trust accounts of $4,721 million and $3,053 million as of December 31, 2003 and 2002, respectively, which are included as nuclear decommissioning trust funds on Exelon's Consolidated Balance Sheets. Exelon anticipates that all trust fund assets will ultimately be used to decommission Exelon's nuclear plants.

SFAS No. 143 provides accounting requirements for retirement obligations (whether statutory, contractual or as a result of principles of promissory estoppel) associated with tangible long-lived assets. Exelon adopted SFAS No. 143 as of January 1, 2003. After considering interpretations of the transitional guidance included in SFAS No. 143, Exelon recorded income of $112 million (net of income taxes) as a cumulative effect of a change in accounting principle in connection with its adoption of this standard in the first quarter of 2003. The components of the cumulative effect of a change in accounting principle, net of income taxes, were as follows:

Generation (net of income taxes of $52)	$80
Generation's investments in AmerGen and Sithe (net of income taxes of $18)	28
ComEd (net of income taxes of $0)	5
Enterprises (net of income taxes of $(1))	(1)
Total	$112

See Note 1—Significant Accounting Policies for net income and earnings per common share for 2002 and 2001, adjusted as if SFAS No. 143 had been applied effective January 1, 2001. The cumulative effect of the change in accounting principle in adopting SFAS No. 143 had no impact on PECO's Consolidated Statements of Income.

The asset retirement obligation (ARO) as of January 1, 2003 was determined under SFAS No. 143 to be $2,366 million. The following table provides a reconciliation of the previously recorded liabilities for nuclear decommissioning to the ARO reflected on the Consolidated Balance Sheets at December 31, 2003 and 2002:

Accumulated depreciation	$2,845
Nuclear decommissioning liability for retired units	1,293
Decommissioning obligation at December 31, 2002	4,138
Net reduction due to adoption of SFAS No. 143	1,772
Asset retirement obligation at January 1, 2003	2,366
Consolidation of AmerGen	487
Accretion expense	161
Expenditures to decommission retired plants	(14)
Classification of Thermal ARO as held for sale	(3)
Asset retirement obligation at December 31, 2003	$2,997

Determination of Asset Retirement Obligation

In accordance with SFAS No. 143, a probability-weighted, discounted cash flow model with multiple scenarios was used to determine the "fair value" of the decommissioning obligation. SFAS No. 143 also stipulates that fair value represents the amount a third party would receive for assuming an entity's entire obligation.

The present value of future estimated cash flows was calculated using credit-adjusted, risk-free rates applicable to the various businesses in order to determine the fair value of the decommissioning obligation at the time of adoption of SFAS No. 143.

Significant changes in the assumptions underlying the items discussed above could materially affect the balance sheet amounts and future costs related to decommissioning recorded in the consolidated financial statements.

Effect of Adopting SFAS No. 143

Exelon was required to re-measure the decommissioning liabilities at fair value using the methodology prescribed by SFAS No. 143. The transition provisions of SFAS No. 143 required Exelon to apply this re-measurement back to the historical periods in which AROs were incurred, resulting in a re-measurement of these obligations at the date the related assets were acquired. Since the nuclear plants previously owned by ComEd were acquired by Exelon on October 20, 2000 as a result of the Merger, Exelon's historical accounting for its ARO associated with those plants has been revised as if SFAS No. 143 had been in effect at the Merger date.

In the case of the former ComEd plants, the calculation of the SFAS No. 143 ARO yielded decommissioning obligations lower than the value of the corresponding trust assets at January 1, 2003. ComEd has previously collected amounts from customers (which were subsequently transferred to Generation) in advance of Generation's recognition of decommissioning expense under SFAS No. 143. While it is expected that the trust assets will ultimately be used entirely for the decommissioning of the plants, the current measurement required by SFAS No. 143 results in an excess of assets over related ARO liabilities. As such, in accordance with regulatory accounting practices and a December 2000 ICC Order, a regulatory liability of $948 million and a corresponding receivable from Generation were recorded at ComEd upon the adoption of SFAS No. 143. At December 31, 2003, the regulatory liability and corresponding receivable from Generation was $1,183 million. Exelon believes that all of the decommissioning assets, prospective earnings thereon and up to $73 million of annual collections from ComEd ratepayers through 2006 will be required to decommission the former ComEd plants. Subsequent to 2006, there will be no further recoveries of decommissioning costs from customers of ComEd. Additionally, any surplus funds after the nuclear stations are decommissioned must be refunded to customers. Exelon expects the regulatory liability and ComEd's corresponding receivable from Generation will be reduced to zero at or before the conclusion of the decommissioning of the former ComEd plants.

In the case of the former PECO plants, the SFAS No. 143 ARO calculation yielded decommissioning obligations greater than the corresponding trust assets at January 1, 2003. As such, a regulatory asset of $20 million and a corresponding payable to Generation were recorded upon adoption of SFAS No. 143 at PECO. As a result of increases in the trust funds due to market conditions and contributions collected from PECO customers, at December 31, 2003, the trust funds exceeded the ARO for the former PECO plants and thus a regulatory liability of $12 million was recorded. Exelon believes that all of the decommissioning assets, prospective earnings thereon, and $29 million of annual collections from PECO ratepayers, which will increase to approximately $33 million beginning in 2004, will be used to decommission the former PECO plants. Exelon also expects the regulatory liability will be reduced to zero at the conclusion of the decommissioning of the former PECO plants. See Note 4 – Regulatory Issues for more information regarding the annual collections from PECO.

At December 31, 2002, prior to the adoption of SFAS No. 143, Exelon's accumulated depreciation included $2,845 million for decommissioning liabilities related to active nuclear plants. This amount was reclassified to an ARO upon the adoption of SFAS No. 143. Exelon also recorded an asset retirement cost (ARC) of $172 million related to the establishment of the ARO related to former PECO plants in accordance with SFAS No. 143. The ARC is being amortized over the remaining lives of the plants.

As discussed above, Exelon re-measured its 2001 decommissioning-related balances associated with the Merger purchase price allocation at ComEd and the January 2001 corporate restructuring as if SFAS No. 143 had been in effect at the Merger date. Exelon concluded that had SFAS No. 143 been in effect, ComEd would not have recorded an impairment of a previously established regulatory asset for decommissioning of its retired nuclear plants as a purchase price allocation adjustment in 2001 as a result of the December 2000 ICC order. As a result, increased net assets would have been transferred to Generation by ComEd in the corporate restructuring. Accordingly, Exelon recorded a reduction of goodwill of approximately $210 million, with a corresponding reduction in its overall decommissioning obligation in connection with the implementation of SFAS No. 143 on January 1, 2003. In addition, Exelon and ComEd recorded a cumulative effect of a change in accounting principle of $5 million to reverse goodwill amortization that had been recorded in 2001. Exelon and ComEd also reclassified a regulatory asset related to nuclear decommissioning costs for retired units of $248 million to regulatory liabilities.

In accordance with the provisions of SFAS No. 143 and regulatory accounting guidance, Exelon recorded a SFAS No. 143 transition adjustment to accumulated other comprehensive income to reclassify $168 million, net of tax, of accumulated net unrealized losses on the nuclear decommissioning trust funds to regulatory assets and liabilities.

Accounting Methodology Under SFAS No. 143

Realized gains and losses on decommissioning trust funds for nuclear generating stations transferred to Generation from ComEd are reflected in other income and deductions in Exelon's Consolidated Statements of Income, while the unrealized gains and losses on marketable securities held in the trust funds adjust the regulatory liability on Exelon's Consolidated Balance Sheets. The increases in the ARO are recorded in operating and maintenance expense as accretion expense. If the trust assets plus future collections permitted by the ICC order are exceeded by the ARO, Exelon is responsible for any shortfall in funding and at that point unrealized gains and losses will be recorded as other comprehensive income. The result of the above accounting is that no net earnings are recorded for investment gains and losses for as long as the trust assets exceed the ARO for the former ComEd plants.

The above accounting practices are also applicable for nuclear generating stations that were transferred to Generation from PECO as a result of the Exelon corporate restructuring on January 1, 2001. Additionally, depreciation expense is recognized on the ARC established upon the adoption of SFAS No. 143. However, as Exelon has the expectation of full recovery from ratepayers of decommissioning costs of PECO's former nuclear generating stations, the result of the above accounting has no earnings impact to Exelon. Therefore, to the extent that the net of decommissioning revenues collected and realized investment income differs from the accretion expense to the ARO and the related depreciation of the ARC, an adjustment to net the amounts to zero is recorded by Exelon for that period with the offset to Exelon's regulatory liability balance.

Prior to Exelon's acquisition of British Energy's 50% interest in AmerGen in December 2003, Exelon accounted for the costs of decommissioning the AmerGen plants through its equity in earnings of AmerGen. In addition, Exelon's proportionate share of other gains and losses on AmerGen's decommissioning trust funds were reflected in Generation's other comprehensive income. Beginning January 2004, realized gains and losses on decommissioning trust funds for AmerGen plants will be reflected in other income and deductions in Exelon's Consolidated Statements of Income, while unrealized gains and losses on marketable securities held in the trust funds will be recorded to accumulated other comprehensive income. The increases in the ARO will be recorded in operating and maintenance expense as accretion expense. At December 31, 2003, trust fund assets available to decommission AmerGen plants totaled $1.1 billion while the ARO totaled $487 million.

Accounting Prior to the Adoption of SFAS No. 143

Prior to January 1, 2003, Exelon accounted 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 recognizing decommissioning collections. Financial activity of the decommissioning trust (e.g., investment income and realized and unrealized gains and losses on trust investments) was 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 would have, over time, established a corresponding liability in accumulated depreciation reflecting the cost to decommission the nuclear generating stations previously owned by PECO.

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. The difference between the decommissioning cost estimate and the decommissioning liability recorded in accumulated depreciation for the former ComEd operating stations was being amortized to depreciation expense on a straight-line basis over the remaining lives of the stations. The decommissioning cost estimate (adjusted annually to reflect inflation) for the former ComEd retired units recorded in deferred credits and other liabilities was 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) was reflected in nuclear decommissioning trust funds in Exelon's Consolidated Balance Sheets with a corresponding gain or expense recorded in Exelon's Consolidated Statements of Income or in other comprehensive income. The offset to the financial activity in the decommissioning trust funds is summarized as follows:

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

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 (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 June 10, 2003, the Court denied the Government's summary judgment motions and set the case for trial on damages for November 2004. Also on June 10, 2003, the Court granted the Government's motion to dismiss claims other than the breach of contract claims. Generation assumed the Standard Contract, as amended, in the 2001 corporate restructuring. Generation is now engaged in pre-trial document and deposition discovery on the damages claims.

In July 2000, PECO entered into an agreement (Amendment) with the DOE relating to PECO's Peach Bottom nuclear generating unit to address the DOE's failure to begin removal of SNF in January 1998 as required by the Standard Contract (Amendment). Under the Amendment, 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 Amendment also provided that, upon PECO's request, the DOE will take title to the SNF and the interim storage facility at Peach Bottom provided certain conditions are met. Generation assumed this contract in the 2001 corporate restructuring.

In November 2000, eight utilities with nuclear power plants filed a Joint Petition for Review against the DOE with the United States Court of Appeals for the Eleventh Circuit seeking to invalidate that portion of the Amendment providing for credits to PECO against nuclear waste fund payments on the 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 Amendment as a whole is invalid. Article XVI(I) of the Amendment provides that if any portion of the Amendment is found to be void, the DOE and Generation agree to negotiate in good faith and attempt to reach an enforceable agreement consistent with the spirit and purpose of the Amendment. That provision further 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 XVI(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.

On August 14, 2003, Generation received a letter from the DOE demanding repayment of $40 million of previously received credits from the Nuclear Waste Fund. The letter also demanded $1.5 million of interest that was accrued as of that date, and Exelon has continued to accrue interest expense each subsequent month. Although a new settlement would offset Generation's payments, Generation nonetheless has reserved its 50% ownership share of these amounts. Because Generation expenses the dry storage casks and capitalizes the permanent components of its spent fuel storage facilities, these reserves increased Generation's operating and maintenance expense approximately $11 million and its capital base approximately $9 million during 2003. The remainder of the recorded obligation to the DOE will be recovered from the co-owner of the facility.

The Standard Contract with the DOE also required 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, 2003, the unfunded liability for the one-time fee with interest was $867 million. The liabilities for spent nuclear fuel disposal costs, including the one-time fee, were transferred to Generation as part of the corporate restructuring.

NOTE 14 • RETIREMENT BENEFITS

Exelon sponsors defined benefit pension plans and postretirement welfare benefit plans applicable to essentially all ComEd, PECO, Generation and Exelon Business Services Company (BSC) employees and certain employees of Enterprises. Essentially all management employees, and electing union employees, hired on or after January 1, 2001 participate in Exelon sponsored cash balance pension plans.

The defined benefit pension plans and postretirement welfare benefit plans are accounted for in accordance with SFAS No. 87, "Employer's Accounting for Pensions" (SFAS No. 87) and SFAS No. 106, "Employers' Accounting for Postretirement Benefits Other than Pensions" (SFAS No. 106). 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, in addition to 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. 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. Exelon uses a December 31 measurement date for the majority of its plans.

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.

During 2003, Exelon announced an amendment related to the benefit provisions of its postretirement welfare benefit plans. The amendment was effective August 1, 2003 and reduced the benefits attributable to prior service through increased retiree cost-sharing for medical coverage. The changes in the postretirement welfare plan design due to the amendment were incorporated into the August 1, 2003 remeasurement of the plan obligation discussed below.

Due to The Exelon Way and an overall reduction in active employees during 2003, certain defined benefit pension plans and postretirement welfare benefit plans were subject to curtailment accounting that resulted in a remeasurement of the plan obligations as of August 1, 2003. The threshold basis for curtailment remeasurement was a reduction in future service greater than 5%. The net benefit obligations of the pension plans and the postretirement welfare benefit plans increased by $48 million and $27 million, respectively, due to the curtailment.

The remeasurements of the plan obligations resulted in accelerated recognition of a portion of the prior service cost generated by the pension and postretirement benefit plans, resulting in the recognition of curtailment charges in operating and maintenance expense related to the pension plans and other postretirement plans during 2003 of $59 million and $21 million, respectively.

On December 22, 2003, Generation purchased British Energy's 50% interest in AmerGen, and as a result, the obligations associated with AmerGen's pension and postretirement welfare plans are reflected in the disclosures below as an acquisition. The net benefit obligations related to AmerGen's pension plans and postretirement benefit plans were $67 million and $80 million, respectively, as of December 31, 2003.

The following tables provide a roll forward of the changes in the benefit obligations and plan assets for the most recent two years:

	Pension Benefits		Other Postretirement Benefits	
	2003	2002	**2003**	2002
Change in benefit obligation:				
Net benefit obligation at beginning of year	**$ 7,854**	$ 7,101	**$ 2,555**	$ 2,331
Service cost	**109**	95	**68**	57
Interest cost	**519**	525	**167**	160
Plan participants' contributions	**–**	–	**15**	8
Plan amendments	**–**	120	**(337)**	–
Actuarial loss	**711**	514	**559**	155
AmerGen acquisition	**67**	–	**80**	–
Curtailments/settlements	**48**	–	**27**	–
Special accounting costs	**–**	4	**48**	–
Gross benefits paid	**(550)**	(505)	**(163)**	(156)
Net benefit obligation at end of year	**$ 8,758**	$ 7,854	**$ 3,019**	$ 2,555
Change in plan assets:				
Fair value of plan assets at beginning of year	**$ 5,395**	$ 6,279	**$ 958**	$ 1,132
Actual return on plan assets	**1,189**	(581)	**227**	(99)
Employer contributions	**367**	202	**134**	73
Plan participants' contributions	**–**	–	**15**	8
AmerGen acquisition	**41**	–	**–**	–
Gross benefits paid	**(550)**	(505)	**(163)**	(156)
Fair value of plan assets at end of year	**$ 6,442**	$ 5,395	**$ 1,171**	$ 958

The following table provides a reconciliation of benefit obligations, plan assets and funded status of the plans:

	Pension Benefits		Other Postretirement Benefits	
	2003	2002	**2003**	2002
Fair value of plan assets at end of year	**$ 6,442**	$ 5,395	**$ 1,171**	$ 958
Benefit obligations at end of year	**8,758**	7,854	**3,019**	2,555
Funding status (plan assets less than plan obligations)	**(2,316)**	(2,459)	**(1,848)**	(1,597)
Amounts not recognized:				
Miscellaneous adjustment	**14**	(3)	**–**	–
Unrecognized net actuarial loss	**2,203**	2,118	**1,129**	767
Unrecognized prior service cost (benefit)	**185**	211	**(420)**	(149)
Unrecognized net transition obligation (asset)	**(8)**	(11)	**86**	102
Net amount recognized	**$ 78**	$ (144)	**$ (1,053)**	$ (877)

The following table provides a reconciliation of the amounts recognized in the Consolidated Balance Sheets as of December 31:

	Pension Benefits		Other Postretirement Benefits	
	2003	2002	**2003**	2002
Prepaid benefit cost	**$ 175**	$ 145	**$ –**	$ –
Accrued benefit cost	**(97)**	(289)	**(1,053)**	(877)
Additional minimum liability	**(1,746)**	(1,815)	**–**	–
Intangible asset	**186**	211	**–**	–
Accumulated other comprehensive income	**1,560**	1,604	**–**	–
Net amount recognized	**$ 78**	$ (144)	**$ (1,053)**	$ (877)

The accumulated benefit obligation (ABO) for all defined benefit pension plans was $8,104 million and $7,355 million at December 31, 2003 and 2002, respectively. The acquisition of AmerGen and assumption of its pension liabilities in December 2003 resulted in a $55 million increase in Exelon's ABO. The following table provides the projected benefit obligation, accumulated benefit obligation, and fair value of plan assets for pension plans with an ABO in excess of plan assets. The table below is also representative of all pension plans with a projected benefit obligation in excess of plan assets.

	December 31, 2003	2002
Projected benefit obligation	**$8,758**	$7,854
Accumulated benefit obligation	**8,104**	7,355
Fair value of plan assets	**6,442**	5,395

The following table provides the components of the net periodic benefit costs (benefits) recognized for the years ended December 31. A portion of the net periodic benefit cost (benefit) is capitalized within the Consolidated Balance Sheets.

	Pension Benefits			Other Postretirement Benefits		
	2003	2002	2001	**2003**	2002	2001
Service cost	**$ 109**	$ 95	$ 94	**$ 68**	$ 57	$ 42
Interest cost	**519**	525	498	**167**	160	161
Expected return on assets	**(584)**	(628)	(625)	**(75)**	(93)	(99)
Amortization of:						
Transition obligation (asset)	**(4)**	(4)	(4)	**10**	10	10
Prior service cost	**16**	16	9	**(54)**	(37)	(9)
Actuarial (gain) loss	**23**	–	(25)	**47**	6	1
Curtailment charge (credit)	**59**	–	(12)	**21**	–	9
Settlement charge (credit)	**–**	–	(9)	**–**	–	–
Net periodic benefit cost (benefit)	**$ 138**	$ 4	$ (74)	**$184**	$103	$ 115
Special accounting costs	**$ –**	$ 4	$ 48	**$ 48**	$ –	$ 3
Other additional information:						
Increase (decrease) in other comprehensive income (net of tax)	**$ 26**	$(1,007)	$ –	**$ –**	$ –	$ –

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 was affected by sharp declines in the equity market from 2000 through 2002. 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. 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 ABO. 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 flows in 2002 or compliance with debt covenants. In 2003, the additional minimum liability was reduced by $69 million. In 2003, shareholders' equity increased by $26 million (net of income taxes) as a result of accounting associated with Exelon's pension plans.

Special accounting costs of $48 million in 2003 represent special health and welfare severance benefits offered through The Exelon Way. These costs were recorded pursuant to SFAS No. 112. See Note 9—Severance Accounting for additional information. Special accounting costs of $4 million in 2002 and $48 million in 2001 represented accelerated separation and enhancement benefits provided to PECO employees expected to be terminated as a result of the Merger.

Prior service cost is amortized on a straight-line basis over the average remaining service period of employees expected to receive benefits under the plans.

The following weighted average assumptions were used to determine the benefit obligations at December 31:

	Pension Benefits			Other Postretirement Benefits		
	2003	2002	2001	**2003**	2002	2001
Discount rate	**6.25%**	6.75%	7.35%	**6.25%**	6.75%	7.35%
Rate of compensation increase	**4.00%**	4.00%	4.00%	**4.00%**	4.00%	4.00%
Health care cost trend on covered charges	**N/A**	N/A	N/A	**10.00% decreasing to ultimate trend of 4.5% in 2011**	8.50% decreasing to ultimate trend of 4.5% in 2008	10.00% decreasing to ultimate trend of 4.5% in 2008

The following weighted average assumptions were used to determine the net periodic benefit costs (benefits) for years ended December 31:

	Pension Benefits			Other Postretirement Benefits		
	2003	2002	2001	**2003**	2002	2001
Discount rate	**6.60-6.75%**	7.35%	7.60%	**6.60-6.75%**	7.35%	7.60%
Expected return on plan assets	**9.00%**	9.50%	9.50%	**8.40%**	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	**8.50% 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

In managing its pension and postretirement plan assets, Exelon utilizes a diversified, strategic asset allocation to efficiently and prudently generate investment returns that will meet the objectives of the investment trusts that hold the plan assets. Asset / liability studies that incorporate specific plan objectives as well as assumptions regarding long-term capital market returns and volatilities generate the specific asset allocations for the trusts. In general, Exelon's investment strategy reflects the belief that over the long term, equities are expected to outperform fixed-income investments. The long-term nature of the trusts make them well suited to bear the risk of added volatility associated with equity securities, and, accordingly, the asset allocations of the trusts usually reflect a higher allocation to equities as compared to fixed-income securities. Non-U.S. equity securities are used to diversify some of the volatility of the U.S. equity market while providing comparable long-term returns. Alternative asset classes, such as private equity and real estate, may be utilized for additional diversification and return potential when appropriate. Exelon's investment guidelines do limit exposure to investments in more volatile sectors.

Exelon generally maintains 60% of its plan assets in equity securities and 40% of its plan assets in fixed-income securities. On a quarterly basis, Exelon reviews the actual asset allocations and follows a rebalancing procedure in order to remain within an allowable range of these targeted percentages.

In selecting the expected rate of return on plan assets, Exelon considers historical returns for the types of investments that its plans hold. Historical returns and volatilities are modeled to determine asset allocations that best meet the objectives of the asset / liability studies. These asset allocations, when viewed over a long-term historical view of the capital markets, yield an expected return on assets in excess of 9%.

Exelon's pension plan weighted average asset allocations at December 31, 2003 and 2002 and target allocation for 2003 were as follows:

		Percentage of Plan Assets at December 31,	
Asset Category	Target Allocation at December 31, 2003	**2003**	2002
Equity securities	60%	**64%**	58%
Debt securities	35-40	**32**	38
Real estate	0-5	**4**	4
Total		**100%**	100%

Exelon's other postretirement benefit plan weighted average asset allocations at December 31, 2003 and 2002 and target allocation for 2003 were as follows:

		Percentage of Plan Assets at December 31,	
Asset Category	Target Allocation at December 31, 2003	**2003**	2002
Equity securities	60-65%	**67%**	61%
Debt securities	35-40	**33**	39
Total		**100%**	100%

Exelon's pension plans and postretirement welfare benefit plans do not directly hold shares of Exelon common stock.

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. A one percentage point change in assumed health care cost trend rates would have the following effects:

Effect of a one percentage point increase in assumed health care cost trend	
on total service and interest cost components	$ 37
on postretirement benefit obligation	$ 372
Effect of a one percentage point decrease in assumed health care cost trend	
on total service and interest cost components	$ (30)
on postretirement benefit obligation	$(312)

Exelon expects to contribute up to approximately $419 million to its pension plans in 2004. These contributions exclude benefit payments expected to be made directly from corporate assets. Of the $419 million expected to be contributed to the pension plans during 2004, $17 million is estimated to be needed to satisfy IRS minimum funding requirements.

Exelon sponsors savings plans for the majority of its employees. The plans allow employees to contribute a portion of their pre-tax income in accordance with specified guidelines. Exelon matches a percentage of the employee contribution up to certain limits. The cost of Exelon's matching contribution to the savings plans totaled $55 million, $63 million and $57 million in 2003, 2002 and 2001, respectively.

NOTE 15 • FAIR VALUE OF FINANCIAL ASSETS AND LIABILITIES

Non-Derivative Financial Assets and Liabilities

As of December 31, 2003 and 2002, Exelon's carrying amounts of cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities are representative of fair value because of the short-term nature of these instruments. Fair values 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 securities held in trust funds and for the same or similar issues for long-term debt and preferred securities.

The carrying amounts and fair values of Exelon's financial liabilities as of December 31, 2003 and 2002 were as follows:

	2003		2002	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Liabilities				
Long-term debt (including amounts due within one year)	**$9,274**	**$9,889**	$14,529	$15,950
Long-term debt to ComEd Transitional Funding Trust and PECO Energy Transition Trust [(a)]	**5,525**	**6,006**	–	–
Long-term debt to financing trusts (including amounts due within one year)	**545**	**567**	–	–
Preferred securities of subsidiaries	**87**	**71**	595	739

(a) Effective July 1, 2003, PECO Trust IV, a financing subsidiary created in May 2003, was deconsolidated from the financial statements in conjunction with the adoption of FIN No. 46. Effective December 31, 2003, ComEd Financing II, ComEd Financing III, ComEd Transitional Funding Trust, PECO Trust III, and PETT were deconsolidated from the financial statements in conjunction with the adoption of FIN No. 46-R. Amounts owed to these financing trusts are recorded as debt to financing trusts within the Consolidated Balance Sheets. See Note 16—Preferred Securities for additional information regarding ComEd Financing II, ComEd Financing III, ComEd Funding LLC, PECO Trust III and PECO Trust IV.

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.

Derivative Instruments

The fair values of Exelon's interest-rate swaps and power purchase and sale contracts are determined using quoted exchange prices, external dealer prices or internal valuation models which utilize assumptions of future energy prices and available market pricing curves.

At December 31, 2003 and 2002, Exelon had $1.3 billion and $2.3 billion, respectively, of notional amounts of interest-rate swaps outstanding with net deferred losses of $44 million and $125 million, respectively, as follows:

	Notional Amount	Exelon Pays	Counterparty Pays	Fair Value **2003**	Fair Value 2002
Fair-Value Hedges					
ComEd	$485	3 Month Libor plus 1.68%–2.50%	6.40%–8.25%	**$ 33**	$ 41
Cash-Flow Hedges					
ComEd	$630[(a)]	4.32% – 5.60%	3 Month Libor	**–**	(52)
Generation	861	5.71% – 5.74%	3 Month Libor	**(77)**	(92)
PETT	274[(b)]	6.58% – 6.94%	6 Month Libor plus 0.02%–0.13%	**–**	(22)
			Net deferred losses	**$(44)**	$(125)

(a) ComEd settled all of its cash flow swaps during 2003.
(b) PECO deconsolidated its financing trusts at December 31, 2003 in conjunction with the adoption of FIN No. 46-R. See Note 1—Accounting Policies and Note 11—Long-Term Debt for further discussion of the adoption of FIN No. 46-R.

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.

During 2003 and 2002, Exelon settled interest-rate swaps in an aggregate notional amounts of $860 million and $200 million, respectively, and recorded pre-tax gains of $1 million and pre-tax losses of $5 million, respectively, which were recorded in other comprehensive income. Additionally, during 2003 and 2002, Exelon settled interest-rate swaps in aggregate notional amounts of $1,070 million and $450 million, respectively, and recorded net pre-tax losses of $45 million and $10 million, respectively, which were recorded as regulatory assets. The pre-tax losses on settlements of interest-rate swaps are being amortized over the life of the related debt to interest expense.

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 purposes. At December 31, 2003 and 2002, Exelon had $213 million and $143 million, respectively, of energy derivatives recorded as net liabilities at fair value on the Consolidated Balance Sheets, which includes the energy derivatives at Generation and Enterprises discussed below.

For the years ended December 31, 2003, 2002, and 2001 Generation recognized net unrealized losses of $16 million, net unrealized gains of $6 million, and net unrealized gains of $16 million, respectively, relating to mark-to-market activity of certain non-trading power purchase and sale contracts pursuant to SFAS No. 133. Mark-to-market activity on non-trading power purchase and sale contracts are reported in fuel and purchased power. For the years ended December 31, 2003, 2002 and 2001, Generation recognized net unrealized losses of $3 million, net unrealized losses of $9 million and net unrealized gains of $14 million, respectively, relating to mark-to-market activity on derivative instruments entered into for trading purposes. Gains and losses associated with financial trading are reported as revenue in the Consolidated Statements of Income. During 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, $15 million was recorded as an increase to fuel expense in 2003 and $16 million was recorded as a reduction to fuel expense in 2002 as a result of contracts being marked to market. The $15 million increase in 2003 was primarily related to the reversal of the 2002 mark-to-market adjustments. It is expected that the remaining $1 million will reverse as fuel expense in 2004. At December 31, 2003 and 2002, Exelon had net assets of $3 million and $20 million, respectively, on the Consolidated Balance Sheets related to Enterprises' mark-to-market contracts. Enterprises' counterparties in these contracts are all investment grade.

As of December 31, 2003, $176 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 changes in interest-rate cash-flow hedges are reclassified into earnings when the forecasted interest payment occurs. Amounts in accumulated other comprehensive income related to changes in energy commodity cash-flow hedges are reclassified into earnings when the forecasted purchase or sale of the energy commodity occurs. The majority of 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.

Available-for-Sale Securities

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 cost bases for the securities held in these trust accounts as of December 31, 2003 and 2002.

	December 31, 2003			
	Amortized Cost	Gross Unrealized Gains	Gross Unrealized Losses	Estimated Fair Value
Cash and cash equivalents(1)	$ 72	$ –	$ –	$ 72
Equity securities	2,402	300	(294)	2,408
Debt securities				
Government obligations	1,574	65	(4)	1,635
Other debt securities	579	29	(2)	606
Total debt securities	2,153	94	(6)	2,241
Total available-for-sale securities	$4,627	$394	$(300)	$ 4,721

(1) Cash and cash equivalents does not include $12 million related to AmerGen nuclear decommissioning trust. AmerGen's nuclear decommissioning trust cash and cash equivalents are classified elsewhere in the table.

	December 31, 2002			
	Amortized Cost	Gross Unrealized Gains	Gross Unrealized Losses	Estimated Fair Value
Cash and cash equivalents	$ 184	$ –	$ –	$ 184
Equity securities	1,763	72	(482)	1,353
Debt securities				
Government obligations	938	62	–	1,000
Other debt securities	514	32	(30)	516
Total debt securities	1,452	94	(30)	1,516
Total available-for-sale securities	$3,399	$166	$ (512)	$ 3,053

Net unrealized gains of $94 million were recognized in regulatory assets, regulatory liabilities or accumulated other comprehensive income in Exelon's Consolidated Balance Sheet at December 31, 2003. Net unrealized losses of $346 million were recognized in accumulated depreciation, regulatory assets and accumulated other comprehensive income in Exelon's Consolidated Balance Sheet at December 31, 2002.

Proceeds from the sale of decommissioning trust investments and gross realized gains and losses on those sales were as follows:

	For the Years Ended December 31,		
	2003	2002	2001
Proceeds from sales	**$2,341**	$1,612	$1,624
Gross realized gains	**219**	56	76
Gross realized losses	**(235)**	(86)	(189)

Net realized losses of $16 million, $32 million and $127 million were recognized in other income and deductions in Exelon's Consolidated Statements of Income for the years ended December 31, 2003, 2002 and 2001, respectively. Additionally, 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. The fixed-income available-for-sale securities held at December 31, 2003 have an average maturity range of seven to nine years. The cost of these securities was determined on the basis of specific identification. See Note 13—Nuclear Decommissioning and Spent Fuel Storage for further information regarding the nuclear decommissioning trusts.

The following table provides information regarding Exelon's available-for-sale securities in an unrealized loss position that are not other-than-temporarily impaired. The table shows the investments' gross unrealized losses and fair value, aggregated by investment category and length of time that individual securities have been in a continuous unrealized loss position, at December 31, 2003.

	Less than 12 months		12 months or more		Total	
	Unrealized losses	Fair value	Unrealized losses	Fair value	Unrealized losses	Fair value
Equity securities	$33	$ 231	$261	$ 775	$294	$1,006
Debt securities						
Government obligations	4	232	—	11	4	243
Other debt securities	2	117	—	2	2	119
Total debt securities	6	349	—	13	6	362
Total temporarily impaired securities	$39	$580	$261	$788	$300	$ 1,368

As of December 31, 2003, Exelon's available-for-sale investments in unrealized loss positions that were not other-than-temporarily impaired were securities held in its nuclear decommissioning trust funds. These investments are held to fund Exelon's decommissioning obligation for its nuclear plants. Nuclear decommissioning activity occurs primarily after a plant is retired, and Generation estimates that decommissioning expenditures funded by the trust assets will begin in 2029.

Exelon evaluates the historical performance, cost basis, and market value of its securities in unrealized loss positions in comparison to related market indices to assess whether or not the securities are permanently impaired. Exelon concluded that the trending of the related market indices and historical performance of these securities over a long-term time horizon indicates that the securities are not other-than-temporarily impaired.

NOTE 16 • PREFERRED SECURITIES

At December 31, 2003 and 2002, Exelon was authorized to issue up to 100,000,000 shares of preferred stock, none of which was outstanding.

Preferred and Preference Stock of Subsidiaries

At December 31, 2003 and 2002, 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)]	**2003**	2002	**2003**	2002
		Shares Outstanding		Dollar Amount	
Series (without mandatory redemption)					
$4.68 (Series D)	$104.00	**150,000**	150,000	**$ 15**	$ 15
$4.40 (Series C)	112.50	**274,720**	274,720	**27**	27
$4.30 (Series B)	102.00	**150,000**	150,000	**15**	15
$3.80 (Series A)	106.00	**300,000**	300,000	**30**	30
$7.48	(b)	**–**	500,000	**–**	50
Total preferred stock		**874,720**	1,374,720	**$87**	$137

(a) Redeemable, at the option of PECO, at the indicated dollar amounts per share, plus accrued dividends.
(b) Redeemed during 2003.

On June 11, 2003, PECO redeemed $50 million of its $7.48 preferred stock at a redemption price of $103.74 per share, plus accrued and unpaid dividends.

At December 31, 2003 and 2002, ComEd preferred stock and ComEd preference stock consisted of 850,000 and 6,810,451 shares authorized, respectively, none of which was outstanding.

Mandatorily Redeemable Preferred Securities

See Note 1—Significant Accounting Policies for a discussion of the adoptions of FIN No. 46 and FIN No. 46-R and the resulting deconsolidation of ComEd Financing II, ComEd Financing III, PECO Trust III and PECO Trust IV from Exelon's consolidated financial statements.

At December 31, 2002, the preferred securities of the financing trusts of ComEd and PECO were recorded in the consolidated financial statements of Exelon as follows:

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

During 2003, the following mandatorily redeemable preferred securities were issued:

Company	Type	Amount	Rate	Maturity
ComEd	Mandatorily Redeemable Preferred Securities–ComEd Financing III	$200	6.35%	March 15, 2033

During 2003, the following mandatorily redeemable preferred securities were retired or redeemed:

Company	Type	Amount	Rate	Maturity
ComEd	Mandatorily Redeemable Preferred Securities–ComEd Financing I	$200	8.48%	September 30, 2035
PECO	Mandatorily Redeemable Preferred Securities–PECO Energy Capital Trust II	$ 50	8.00%	June 6, 2037

The securities issued by the PECO trusts represent Company—Obligated Mandatorily Redeemable Preferred Securities of a Partnership (COMPrS) having a distribution rate and liquidation value equivalent to the trust securities. The COMPrS 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 COMPrS from the trust in exchange for the trust securities so held. Each series of COMPrS 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 COMPrS.

On March 20, 2003, ComEd Financing I, a financing subsidiary of ComEd, redeemed $200 million of 8.48% trust preferred securities at a redemption price of 100% of the principal amount, plus accrued distributions. ComEd redeemed $206 million of 8.48% subordinated debentures issued to ComEd Financing I. The preferred securities were refinanced with the proceeds from a March 17, 2003 issue of $200 million of 6.35% trust preferred securities by ComEd Financing III, a financing subsidiary of ComEd, which are mandatorily redeemable in 2033. The 8.48% subordinated debentures were refinanced with the proceeds from a March 17, 2003 issue of $206 million of 6.35% subordinated debentures due 2033 from ComEd to ComEd Financing III.

During June 2003, PECO issued $103 million of 5.75% subordinated debentures due 2033 to PECO Trust IV in connection with the issuance by PECO Trust IV of $100 million of 5.75% preferred securities that are mandatorily redeemable in 2033. The proceeds of the issue were used to redeem the trust preferred securities discussed below and preferred stock as disclosed below.

Also on June 24, 2003, PECO Energy Capital Trust II, a financing subsidiary of PECO, redeemed $50 million of its 8.00% trust preferred securities at a redemption price of $25 per trust receipt, plus accrued and unpaid distributions. PECO redeemed $52 million of 8.00% subordinated debentures to PECO Energy Capital Trust II.

ComEd Financing II and ComEd Financing III are 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 interest expense on the debentures and deferrable interest securities was included in distributions on preferred securities of subsidiaries in the Consolidated Statements of Income and is deductible for income tax purposes.

The preferred securities issued by each of ComEd Financing II and ComEd Financing III 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 preferred securities issued by PECO Trust III 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 a change in terms of the preferred securities, listing status on a national securities exchange, ratings by nationally recognized rating agencies, or rights of holders of the preferred securities, or that would result in certain Federal income tax consequences; (ii) with respect to certain amendments to the applicable trust agreement or (iii) for certain voting privileges that arise upon an event of default under the applicable trust agreement. The preferred securities issued by PECO Trust IV 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 PECO guarantee agreement.

NOTE 17 • COMMON STOCK

At December 31, 2003 and 2002, common stock without par value consisted of 600,000,000 and 600,000,000 shares authorized and 328,182,522 and 323,312,586 shares outstanding, respectively. See Note 24 – Subsequent Events for information regarding a quarterly dividend declared on January 27, 2004 and a proposed stock split.

Stock-Based Compensation Plans

Exelon maintains Long-Term Incentive Plans (LTIPs) for certain full-time salaried employees. The types of long-term incentive awards that have been granted under the LTIPs are non-qualified options to purchase shares of Exelon's common stock and common stock awards. At December 31, 2003, there were options for approximately 10,600,000 shares remaining for issuance under the LTIPs.

The exercise price of the stock options is equal to the fair market value of the underlying stock on the date of option grant. Options granted under the LTIPs become exercisable upon attainment of a target share value and/or date. All options expire 10 years from the date of grant. Information with respect to the LTIPs at December 31, 2003 and changes for the three years then ended, is as follows:

	Shares **2003**	Weighted Average Exercise Price (per share) **2003**	Shares 2002	Weighted Average Exercise Price (per share) 2002	Shares 2001	Weighted Average Exercise Price (per share) 2001
Balance at January 1	**15,886,990**	**$ 45.80**	14,039,996	$43.96	15,287,859	$ 42.13
Options granted/assumed	**3,173,200**	**49.69**	3,938,632	47.12	629,200	66.42
Options exercised	**(4,508,695)**	**38.05**	(1,821,339)	33.37	(1,695,474)	34.84
Options canceled	**(397,802)**	**50.18**	(270,299)	53.62	(181,589)	52.64
Balance at December 31	**14,153,693**	**$ 49.01**	15,886,990	$45.80	14,039,996	$43.96
Exercisable at December 31	**9,016,348**	**$48.66**	10,491,184	$43.96	8,006,193	$ 38.75
Weighted average fair value of options granted during year		**$ 11.03**		$ 13.62		$ 19.59

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 2003, 2002 and 2001, respectively:

	2003	2002	2001
Dividend yield	**3.3%**	3.3%	3.2%
Expected volatility	**30.5%**	36.8%	36.8%
Risk-free interest rate	**3.0%**	4.6%	4.9%
Expected life (years)	**5.0**	5.0	5.0

At December 31, 2003, 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	38,300	4.15	$19.69	38,300	$ 19.69
$20.01-$30.00	449,917	2.73	25.29	449,917	25.29
$30.01-$40.00	2,706,761	5.48	37.84	2,706,761	37.84
$40.01-$50.00	6,512,786	8.28	47.67	1,736,699	45.27
$50.01-$60.00	3,820,336	6.87	59.31	3,725,473	59.45
$60.01-$70.00	625,593	7.07	67.29	359,198	67.06
Total	14,153,693			9,016,348	

Exelon common share awards of 450,979, 590,074, and 426,794 shares were granted under Exelon's LTIPs and board compensation plans during 2003, 2002 and 2001, respectively. Total accumulated compensation cost of $88 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 $68 million includes amortization expense of $31 million, $20 million and $11 million during 2003, 2002 and 2001, 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 209,326, 257,455 and 137,648 shares of Exelon common stock under the ESPP in 2003, 2002 and 2001, respectively.

Fund Transfer Restrictions

Under applicable law, 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 applicable Federal law, Exelon, ComEd, PECO and Generation can pay dividends only from retained, undistributed or current earnings. Under Illinois law, ComEd may not pay any dividend on its stock unless "its earnings and earned surplus are sufficient to declare and pay same after provision is made for reasonable and proper reserves," or unless it has specific authorization from the ICC. At December 31, 2003 and 2002, Exelon had retained earnings of $2.3 billion and $2.0 billion, respectively, which included ComEd retained earnings of $883 million and $577 million (of which $709 million has been appropriated for future dividends at December 31, 2003), PECO retained earnings of $546 million and $401 million, and Generation undistributed earnings of $602 million and $924 million, respectively. At December 31, 2003 and 2002, Exelon's common equity to total capitalization ratio was 35% and 32%, respectively.

Undistributed Earnings of Equity Method Investments

Exelon had consolidated undistributed earnings (losses) of equity method investments of $(55) million and $145 million at December 31, 2003 and 2002, respectively.

NOTE 18 • 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):

	2003	2002	2001
Average common shares outstanding	**326**	322	320
Assumed exercise of stock options	**3**	3	2
Average dilutive common shares outstanding	**329**	325	322

The number of stock options not included in the calculation of diluted common shares outstanding due to their anti-dilutive effect was approximately four million, five million, and five million for 2003, 2002, and 2001, respectively.

NOTE 19 • COMMITMENTS AND CONTINGENCIES

Nuclear Insurance

The Price-Anderson Act limits the liability of nuclear reactor owners for claims that could arise from a single incident. As of January 1, 2004, the limit is $10.9 billion and is subject to change to account for the effects of inflation and changes in the number of licensed reactors. Through its subsidiaries, Exelon carries the maximum available commercial insurance of $300 million for each operating site and the remaining $10.6 billion is provided through mandatory participation in a financial protection pool. Under the Price-Anderson Act, all nuclear reactor licensees can be assessed a maximum charge per reactor per incident. Effective August 20, 2003, the maximum assessment for all nuclear operators per reactor per incident (including a 5% surcharge) increased from $89 million to $101 million, 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 and was subsequently extended to the end of 2003 by the U.S. Congress. Only facilities applying for NRC licenses subsequent to the expiration of the Price-Anderson Act are affected. Existing commercial generating facilities, such as those owned and operated by Generation, remain subject to the provisions of the Price-Anderson Act and are unaffected by its expiration.

Exelon is a member of an industry mutual insurance company, Nuclear Electric Insurance Limited (NEIL), which provides property damage, decontamination and premature decommissioning insurance for each station for losses resulting from damage to its nuclear plants. In the event of an accident, insurance proceeds must first be used for reactor stabilization and site decontamination. If the decision is made to decommission the facility, a portion of the insurance proceeds will be allocated to a fund, which 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 $170 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, NEIL provides replacement power cost insurance in the event of a major accidental outage at a nuclear station. The premium for this coverage is subject to assessment for adverse loss experience. Including the AmerGen sites, Exelon's maximum share of any assessment is $61 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, results of operations and liquidity.

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.

At December 31, 2003, 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 contract, as expressed in the following tables:

	Net Capacity Purchases(1)	Power Only Sales	Power Only Purchases	Transmission Rights Purchases(2)
2004	$ 716	$3,393	$ 1,661	$ 113
2005	414	1,088	429	86
2006	410	290	276	3
2007	492	80	253	–
2008	434	–	226	–
Thereafter	3,880	–	723	–
Total	$6,346	$ 4,851	$3,568	$202

(1) Generation will take 1,696 MWs of non-option coal capacity, 687 MWs of option coal capacity, 1,084 MWs of Collins Station capacity and 391 MWs of peaking capacity from Midwest Generation in 2004, the fifth and final year of the contract. In total, Generation has retained 3,858 MWs of capacity under the terms of the three existing PPAs with 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 Generation 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. Net capacity purchases also include tolling agreements that are accounted for as operating leases.

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

In connection with the 2001 corporate restructuring, Generation entered into a PPA with ComEd under which Generation has agreed to supply all of ComEd's load requirements through 2004. Prices for this energy vary depending upon the time of day and month of delivery. An extension of this contract for 2005 and 2006 has been agreed to by ComEd and Generation with substantially the same terms as the PPA currently in effect, except for the prices of energy which were reset to reflect the current rates at the time the extension was agreed to. This extension must still be filed with the ICC. Subsequent to 2006, ComEd will obtain all of its supply from market sources, which could include Generation. Additionally, Generation entered into a PPA with PECO under which PECO obtains substantially all of its electric supply from Generation through 2010. Also, under the restructuring, PECO assigned its rights and obligations under various PPAs and fuel supply agreements to Generation. Generation supplies power to PECO from the transferred generation assets, assigned PPAs and other market sources.

Other Purchase Obligations

In addition to Exelon's energy commitments as described above, Exelon has commitments to purchase fuel supplies for nuclear generation and various other purchase commitments related to the normal day-to-day operations of Exelon's business. As of December 31, 2003, these commitments were as follows:

		Expiration within			
	Total	2004	2005-2006	2007-2008	2009 and beyond
Fuel purchase agreements [(a)]	$3,034	$476	$825	$582	$1,151
Other purchase commitments [(b)]	145	31	71	38	5

(a) Fuel purchase agreements—Commitments to purchase fuel supplies for nuclear and fossil generation.
(b) Other purchase commitments—Commitments for spent fuel storage casks and other disposal services at nuclear generating facilities, minimum spend requirements related to the sale of InfraSource (see Note 2—Acquisitions and Dispositions) and amounts committed for information technology services.

Two affiliates of Exelon New England have long-term supply agreements through December 2022 with Distrigas of Massachusetts, LLC (Distrigas) for gas supply, primarily for the Boston Generating units. Under the agreements, prices are indexed to New England gas markets. Exelon New England has guaranteed these entities' financial obligations to Distrigas under the Distrigas agreements. It is currently anticipated that Exelon New England's guaranty to Distrigas will continue following the eventual transfer of the ownership interests in Boston Generating. This guaranty is non-recourse to Generation. At December 31, 2003, Exelon New England had net assets of approximately $70 million, exclusive of the Boston Generating net assets.

Commercial Commitments

Exelon's commercial commitments as of December 31, 2003, 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 obligations, were as follows:

		Expiration within			
	Total	2004	2005-2006	2007-2008	2009 and beyond
Letters of credit (non-debt) [(a)]	$ 185	$ 185	$ –	$ –	$ –
Letters of credit (long-term debt) – interest coverage [(b)]	13	13	–	–	–
Surety bonds [(c)]	555	330	92	4	129
Performance guarantees [(d)]	201	–	–	–	201
Energy marketing contract guarantees [(e)]	216	205	11	–	–
Nuclear insurance guarantees [(f)]	1,710	–	–	–	1,710
Lease guarantees [(g)]	22	–	2	–	20
Midwest Generation Capacity Reservation Agreement guarantee [(h)]	32	3	7	8	14
Total commercial commitments	$2,934	$736	$112	$12	$2,074

(a) Letters of credit (non-debt)—Exelon and certain of its subsidiaries maintain non-debt letters of credit to provide credit support for certain transactions as requested by third parties. As of December 31, 2003, Exelon had $146 million of outstanding letters of credit (non-debt) issued under its $1.5 billion credit agreements. Guarantees of $102 million have been issued to provide support for certain letters of credit as required by third parties.
(b) Letters of credit (long-term debt) interest coverage—Reflects the interest coverage portion of letters of credit supporting floating-rate pollution control bonds. The principal amount of the floating-rate pollution control bonds of $363 million is reflected in long-term debt in Exelon's Consolidated Balance Sheet.
(c) Surety bonds—Guarantees issued related to contract and commercial surety bonds, excluding bid bonds.
(d) Performance guarantees—Guarantees issued to ensure execution under specific contracts.
(e) Energy marketing contract guarantees—Guarantees issued to ensure performance under energy commodity contracts.
(f) Nuclear insurance guarantees—Guarantees of nuclear insurance required under the Price-Anderson Act. $1.0 billion of this total exposure is exempt from the $4.5 billion PUHCA guarantee limit by SEC rule.
(g) Lease guarantees—Guarantees issued to ensure payments on building leases.
(h) Midwest Generation Capacity Reservation Agreement guarantee—In connection with ComEd's agreement with the City of Chicago entered into on February 20, 2003, Midwest Generation assumed from Chicago a Capacity Reservation Agreement that Chicago had entered into with Calumet Energy Team, LLC. ComEd will reimburse Chicago for any nonperformance by Midwest Generation under the Capacity Reservation Agreement. Under FIN No. 45, $3 million is included as a liability on Exelon's Consolidated Balance Sheets at December 31, 2003.

Additionally, Exelon could be required to guarantee up to an additional $42 million related to various construction and tax obligations associated with the Boston Generating facilities.

Environmental Issues

Exelon's operations have in the past and may in the future require substantial expenditures in order to comply with environmental laws. Additionally, under Federal and state environmental laws, Exelon, through its subsidiaries, is generally liable for the costs of remediating environmental contamination of property now or formerly owned by Exelon and of property contaminated by hazardous substances generated by Exelon. Exelon 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 66 sites where former manufactured gas plant (MGP) activities have or may have resulted in actual site contamination. Of these 66 sites, the Illinois Environmental Protection Agency and the Pennsylvania Department of Environmental Protection have approved the cleanup of 9 sites, and of the remaining sites, 57 are currently under some degree of active study and/or remediation. 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, 2003 and 2002, Exelon had accrued $129 million and $156 million, respectively, for environmental investigation and remediation costs, including $105 million and $125 million, respectively, for MGP investigation and remediation that currently can be reasonably estimated. Included in the environmental investigation and remediation cost obligations as of December 31, 2003 and 2002 are $105 million and $97 million, respectively, that have been recorded on a discounted basis (reflecting discount rates of 5.0% in 2003 and from 5.0% to 4.6% in 2002). Such estimates before the effects of discounting were $138 million and $138 million at December 31, 2003 and 2002, respectively (reflecting inflation rates of 2.5% in 2003 and from 1.6% to 2.5% in 2002). Exelon cannot reasonably estimate whether it will incur other significant liabilities for additional investigation and remediation costs at these or additional sites identified by Exelon, environmental agencies or others, or whether such costs will be recoverable from third parties including ratepayers.

As of December 31, 2003, Exelon anticipates that payments related to the discounted environmental investigation and remediation costs, recorded on an undiscounted basis were:

2004	$ 19
2005	23
2006	20
2007	9
2008	6
Remaining years	61
Total payments	$138

In December 2003, PECO updated its accounting estimate related to the reserve for environmental remediation. Based on an update of an independently prepared environmental remediation study on 27 MGP sites, PECO increased the environmental reserve by $18 million, with an offsetting increase to the MGP regulatory asset. See Note 20—Supplemental Financial Information for further discussion of the MGP regulatory asset.

Leases

Minimum future operating lease payments, including lease payments for vehicles, real estate, computers, rail cars and office equipment, as of December 31, 2003 were:

2004	$ 49
2005	49
2006	47
2007	43
2008	43
Remaining years	512
Total minimum future lease payments[a]	$743

(a) Generation's tolling agreements are accounted for as operating leases and are reflected as net capacity purchases in the energy commitments table above.

Rental expense under operating leases totaled $57 million, $85 million, and $75 million in 2003, 2002, and 2001, respectively.

Litigation

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 and for breach of contract. On November 25, 2002, the court granted the 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. While ComEd cannot currently predict the outcome of this action, Exelon does not believe that it will have a material adverse impact on its results of operations.

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. Several of these actions resulted in nominal jury verdicts or were settled or dismissed. One action resulted in an award for the plaintiffs for a more substantial amount, but was reversed on April 22, 2003 by the Tenth Circuit Court of Appeals and remanded for retrial. An appeal by the plaintiffs to the United States Supreme Court was denied on November 10, 2003. No date has been set for a new trial.

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. Generation cannot predict the ultimate outcome of the cases.

The U.S. 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 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 and Mitsubishi Litigation. In May 2002, Raytheon Corporation (Raytheon) filed an arbitration against Sithe Fore River Development, LLC (now Fore River Development, LLC) in the International Chamber of Commerce Court of Arbitration (Arbitration Court). Raytheon is seeking equitable relief and damages totaling over $45 million for alleged owner-caused performance delays and force majuere events 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. Hearings by the Arbitration Court with respect to liability were held in January and February 2003. On May 12, 2003, the Arbitration Court issued an interim order finding in favor of Raytheon on liability, but limited the grounds upon which Raytheon could claim schedule and cost relief. The Arbitration Court ordered the parties to proceed to a damages phase to determine what, if any, damages Raytheon may recover. Hearings by the Arbitration Court with respect to damages were conducted in June and July 2003 and a final decision is expected in the first quarter of 2004.

In a related proceeding, on October 2, 2003, Mitsubishi Heavy Industries, LTD (MHI) and Mitsubishi Heavy Industries of America (MHIA) filed an action in the New York Supreme Court against Fore River Development, LLC and Mystic Development, LLC (collectively, the Project Companies) seeking to enjoin these indirect subsidiaries of Generation from drawing upon letters of credit posted to guarantee MHI's performance under certain gas turbine contracts. MHI and MHIA also is seeking $34 million from these entities in connection with work performed on these contracts. The Project Companies filed a third-party complaint against Raytheon, claiming that Raytheon was responsible for the MHI and MHIA contracts.

On August 29, 2003, Raytheon filed an action against the Project Companies and BNP Paribas in the Massachusetts Superior Court (Superior Court) alleging that the Project Companies and BNP Paribas had failed to provide adequate assurance that Raytheon would be paid the remaining amounts due under the Fore River and Mystic EPC contracts. Raytheon is seeking: (1) an injunction preventing the Project Companies and BNP Paribas from drawing upon certain letters of credit guaranteeing Raytheon's performance; (2) the right to terminate the construction contracts; and (3) an order allowing Raytheon to seize project funds totaling approximately $40 million. Raytheon subsequently dismissed BNP Paribas from the litigation. On November 25, 2003, the Massachusetts Superior Court dismissed Raytheon's claims in Massachusetts holding that Raytheon's claims should have been brought in the New York Supreme Court proceeding. As a result of this decision, all of the litigation was transferred and consolidated into the New York Supreme Court action and all parties have moved for summary judgment. The court has not yet issued any decision.

Clean Air Act. On June 1, 2001, the EPA issued to a subsidiary of the Company a Notice of Violation (NOV) and Reporting Requirement pursuant to Sections 113 and 114 of the Clean Air Act. The NOV alleges numerous exceedances of opacity limits and violations of opacity-related monitoring, recording and reporting requirements at Mystic Station in Everett, Massachusetts. On January 8, 2002, the EPA indicated that it had decided to resolve the NOV through an administrative compliance order and a judicial civil penalty action. In March 2002, the EPA issued and Mystic I, LLC, doing business as Mystic Generating (formerly known as Exelon Mystic Generating, LLC) (Mystic), a wholly owned subsidiary of the Company, voluntarily entered a Compliance Order and Reporting Requirement (Order) regarding Mystic Station. Under the Order, Mystic Station installed new ignition equipment on three of the four units at the plant. Mystic Station also undertook an extensive opacity monitoring and testing program for all four units at the plant to help determine if additional compliance measures are needed. Pursuant to the requirements of the Order, the subsidiary switched three of the four units to a lower sulfur fuel oil by September 1, 2002. The Order did not address civil penalties. By letter dated April 21, 2003, the United States Department of Justice notified the subsidiary that, at the request of the EPA, it intended to bring a civil penalty action, but also offered the opportunity to resolve the matter through settlement discussions. Mystic has entered into a consent decree with the EPA and the Department of Justice, the net discounted cost of which is approximately $4 million. The consent decree is subject to the approval of the United States District Court of the District of Massachusetts.

Real Estate Tax Appeals. PECO and Generation are each challenging real estate taxes assessed on nuclear plants since 1997. PECO is involved in litigation in which it is contesting taxes assessed in 1997 under the Pennsylvania Public Utility Realty Tax Act of March 4, 1971, as amended (PURTA) and has appealed local real estate assessments for 1998 and 1999 on the Limerick Generating Station (Montgomery County, PA) (Limerick) and Peach Bottom Atomic Power Station (York County, PA) (Peach Bottom) plants. Generation is involved in real estate tax appeals for 2000 through 2003, also regarding the valuation of its Limerick and Peach Bottom plants, its Quad Cities Station (Rock Island County, IL) and, through its wholly owned subsidiary AmerGen, Three Mile Island Nuclear Station (Dauphin County, PA).

During 2003, upon completion of updated nuclear plant appraisal studies, Exelon recorded reductions of $74 million to reserves recorded for exposures associated with the real estate taxes. While Exelon believes the resulting reserve balances as of December 31, 2003 reflect the most likely probable expected outcome of the litigation and appeals proceedings in accordance with SFAS No. 5, "Accounting for Contingencies," the ultimate outcome of such matters could result in additional unfavorable or favorable adjustments to the consolidated financial statements of Exelon, and such adjustments could be material.

General. Exelon is involved in various other litigation matters that are being defended and handled in the ordinary course of business, and Exelon maintains accruals for such costs that are probable of being incurred and subject to reasonable estimation. The ultimate outcome of such matters, as well as the matters discussed above, while uncertain, is not expected to have a material adverse effect on Exelon's financial condition or results of operations.

Capital Commitments

Exelon has a 74% interest in Southeast Chicago, which owns a peaking facility in Chicago. Southeast Chicago is obligated to make equity distributions of $51 million over the next 20 years to the party, which is not affiliated with Exelon, which owns the remaining 26% interest. This amount reflects a return of that party's investment in Southeast Chicago. Exelon has the right to purchase, generally at a premium, and the other party has the right to require Exelon to purchase, generally at a discount, the 26% interest in Southeast Chicago. Additionally, Exelon may be required to purchase the remaining 26% interest upon the occurrence of certain events, including Exelon's failure to maintain an investment grade rating. In conjunction with the adoption of SFAS No. 150 on July 1, 2003, Exelon reclassified the minority interest associated with Southeast Chicago to a long-term liability. The total minority interest related to Southeast Chicago was $51 million as of December 31, 2003. Prior periods were not restated.

Exelon has committed to making an additional investment in the Aladdin thermal facility in 2004 of approximately $19 million for the repayment of debt, which may result in prepayment penalties and the need for additional investment. See Note 2 – Acquisitions and Dispositions for further information regarding agreement to sell the Aladdin thermal facility.

Credit Contingencies

Dynegy. 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, 2003, Exelon has credit risk associated with Dynegy through Generation's investment in Sithe. Sithe is a 60% owner of the Independence generating station, a 1,028-MW gas-fired facility that has an energy-only long-term tolling agreement with Dynegy, with a related financial swap arrangement. Sithe has entered into a contract to purchase the remaining 40% interest of the Independence generating station. As of December 31, 2003, 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 were unable to fulfill the terms of this agreement, Sithe would be required to impair this financial swap asset. Exelon estimates, as a 50% owner of Sithe, that the impairment would result in an after-tax reduction of its net income of approximately $5 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, Exelon 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 up to $30 million, net of a FIN No. 45 guarantee recorded in connection with Generation's sale of 50% of Sithe to Reservoir. In the event of a sale of Exelon's investment in Sithe to a third party, proceeds from the sale could be negatively affected by up to $74 million, which would represent an after-tax loss of up to $43 million. Additionally, the future economic value of AmerGen's purchased power arrangement with Illinois Power, a subsidiary of Dynegy, could be affected by events related to Dynegy's financial condition. On February 3, 2004, Dynegy announced an agreement to sell its subsidiary Illinois Power Company to a third party, which, upon closing of the transaction, would reduce Generation's credit risk associated with Dynegy.

Midwest Generation. On February 20, 2003, ComEd entered into separate agreements with Chicago and with Midwest Generation (Midwest Agreement). Under the terms of the agreement with Chicago, ComEd will pay Chicago $60 million over ten years ($6 million was paid during 2003) 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 Midwest Agreement, ComEd received $32 million from Midwest Generation during 2003 to relieve Midwest Generation's obligation under the fossil sale agreement. Midwest Generation also assumed from Chicago a Capacity Reservation Agreement that Chicago had entered into with Calumet Energy Team, LLC (CET), which is effective through June 2012. ComEd is obligated to reimburse Chicago for any nonperformance by Midwest Generation under the Capacity Reservation Agreement and paid approximately $2 million for amounts owed to CET by Chicago at the time the agreement was executed. In 2003, ComEd recorded a guarantee liability of $4 million under the provisions of FIN No. 45 related to its obligation to reimburse Chicago for any nonperformance by Midwest Generation. The value of this guarantee liability was $3 million as of December 31, 2003. The net effect of the settlement to ComEd will be amortized on a straight-line basis over the remaining life of the franchise agreement with Chicago.

Income Tax Refund Claims

ComEd and PECO have entered into several agreements with a tax consultant related to the filing of refund claims with the IRS and have made refundable prepayments of $11 million and $1 million, respectively, during 2003 for potential fees associated with these agreements. PECO made $4 million in refundable prepayments associated with these agreements prior to 2003. The fees for these agreements are contingent upon a successful outcome and are based upon a percentage of the refunds recovered from the IRS, if any. As such, ultimate net cash outflows to Exelon related to these agreements will either be positive or neutral depending upon the outcome of the refund claim with the IRS. These potential tax benefits and associated fees could be material to the financial position, results of operations and cash flows of Exelon. ComEd's tax benefits for periods prior to the Merger would be recorded as a reduction of goodwill pursuant to a reallocation of the Merger purchase price. Exelon cannot predict the timing of the final resolution of these refund claims.

Derivatives

PETT has 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 $11 million at December 31, 2003. As of December 31, 2003, PETT, a wholly owned subsidiary, was deconsolidated from the financial statements of PECO.

NOTE 20 • SUPPLEMENTAL FINANCIAL INFORMATION

Supplemental Income Statement Information

	For the Years Ended December 31,		
	2003	2002	2001
Depreciation, amortization and accretion			
Property, plant and equipment (a)	**$ 736**	$ 729	$ 697
Regulatory assets	**380**	472	445
Nuclear fuel (b)	**396**	374	393
Decommissioning (c)	**196**	126	144
Goodwill	**–**	–	155
Other	**10**	–	–
Total depreciation, amortization and accretion	**$1,718**	$1,701	$1,834

(a) Includes amortization of capitalized software costs.
(b) Included in operating and maintenance expense in the Consolidated Statements of Income.
(c) Prior to the adoption of SFAS No. 143 on January 1, 2003 these amounts were recorded in depreciation expense. Upon adoption of SFAS No. 143, these amounts were recorded in operating and maintenance expense in Exelon's Consolidated Statements of Income. See Note 13 – Nuclear Decommissioning and Spent Fuel Storage for further discussion of the adoption of SFAS No. 143.

	For the Years Ended December 31,		
	2003	2002	2001
Taxes other than income			
Utility (a)	**$440**	$439	$377
Real estate	**65**	149	140
Payroll	**92**	98	88
Other (b)	**(16)**	23	18
Total	**$ 581**	$709	$623

(a) Municipal and state utility taxes are also recorded in revenues on Exelon's Consolidated Statements of Income.
(b) Includes a credit of $25 million in 2003 due to a favorable settlement of coal use tax issues at ComEd related to periods prior to the Merger.

	For the Years Ended December 31,		
	2003	2002	2001
Other, net			
Investment income	**$ 117**	$ 118	$ 47
Gain (loss) on disposition of assets, net	**(25)**	201	4
Write-down of impaired investments	**(309)**	(47)	(36)
AFUDC, equity and borrowed	**10** (a)	19	18
Reserve for potential plant disallowance	**12**	(12)	–
Other	**8**	21	46
Total	**$ (187)**	$300	$ 79

(a) In 2003, the debt portion of AFUDC of $6 million was recorded as a non-cash credit to interest expense.

Supplemental Cash Flow Information

	For the Years Ended December 31,		
	2003	2002	2001
Cash paid during the year:			
Interest (net of amount capitalized)	**$801**	$905	$963
Income taxes (net of refunds)	**$728**	$ 614	$749
Non-cash investing and financing activities:			
Regulatory asset fair value adjustment	**$ –**	$ –	$ 347
Resolution of certain tax matters and Merger severance adjustment	**–**	14	–
Purchase accounting estimate adjustments	**59**	–	(85)
Capital lease obligations	**–**	52	–
Issuance of InfraSource stock	**–**	–	35
Contribution of land from minority interest of consolidated subsidiary	**–**	12	–
Note received in connection with the sale of Sithe to Reservoir	**92**	–	–
Note issued to Sithe in the Exelon New England acquisition	**2**	534	–
Issuance of note payable to acquire synthetic fuel interests	**238**	–	–

Supplemental Balance Sheet Information

	December 31, 2003	2002
Investments		
Direct financing leases	**$465**	$ 445
Energy services and other ventures	**170**	177
Affordable housing projects	**77**	88
Investment in subsidiaries and joint ventures [(a)]	**73**	16
Investment in EXRES SHC, Inc. [(b)]	**47**	–
Investment in Sithe [(b)]	**–**	478
Investment in AmerGen [(c)]	**–**	160
Communication ventures	**5**	39
Total	**$ 837**	$1,403

(a) Includes investments in financing trusts which were not consolidated within the financial statements of Exelon at December 31, 2003 pursuant to the provisions of FIN No. 46-R. See Note 1—Significant Accounting Policies for further discussion of the effects of FIN No. 46-R.
(b) On November 25, 2003, Generation, Reservoir and Sithe completed a series of transactions that restructured the ownership of Sithe, with Generation continuing to own a 50% interest in Sithe through EXRES SHC, Inc. See Note 3—Sithe for further information on these transactions.
(c) On December 22, 2003, Generation purchased British Energy's 50% interest in AmerGen. See Note 2—Acquisitions and Dispositions for further information.

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 were as follows:

	December 31, 2003	2002
Total minimum lease payments	**$1,492**	$1,492
Less: unearned income	**1,027**	1,047
Net investment in direct financing leases	**$ 465**	$ 445

The following tables provide information about the regulatory assets and liabilities of ComEd and PECO as of December 31, 2003 and 2002.

ComEd	December 31, 2003	2002
Regulatory assets (liabilities)		
Nuclear decommissioning	**$ (1,183)**	$ –
Removal costs	**(973)**	(933)
Reacquired debt costs and interest-rate swap settlements	**172**	84
Recoverable transition costs	**131**	175
Deferred income taxes	**(61)**	(68)
Nuclear decommissioning costs for retired plants	**–**	248
Other	**23**	8
Total	**$(1,891)**	$(486)

PECO	December 31, 2003	2002
Regulatory assets		
Competitive transition charges	**$4,303**	$4,639
Deferred income taxes	**762**	729
Non-pension postretirement benefits	**58**	64
Reacquired debt costs	**49**	53
MGP regulatory asset	**34**	20
DOE facility decommissioning	**26**	32
Nuclear decommissioning	**(12)**	–
Other	**6**	9
Long-term regulatory assets	**5,226**	5,546
Deferred energy costs (current asset)	**81**	31
Total	**$5,307**	$ 5,577

Nuclear Decommissioning Costs. These costs represent the amount of future nuclear decommissioning costs that exceed (regulatory asset) or are less than (regulatory liability) the associated decommissioning trust fund assets. ComEd and PECO believe the trust fund assets including any future collections from ratepayers will equal the associated future decommissioning costs. See Note 13—Nuclear Decommissioning and Spent Fuel Storage.

Removal Costs. These amounts represent funds received from ratepayers to cover the future removal of property, plant and equipment. See Note 6—Property, Plant and Equipment for further information.

Reacquired Debt Costs and Interest-Rate Swaps. The reacquired debt costs represent premiums paid for the early extinguishment and refinancing of long-term debt, which is amortized over the life of the new debt issued to finance the debt redemption. Interest-rate swap settlements are deferred and amortized over the period that the related debt is outstanding.

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. 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 4—Regulatory Issues for discussion of recoverable transition cost amortization.

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 regulatory assets and liabilities associated with deferred income taxes, recorded in compliance with SFAS No. 71 and SFAS No. 109, include the deferred tax effects associated principally with liberalized depreciation accounted for in accordance with the ratemaking policies of the ICC and PUC, as well as the revenue impacts thereon, and assume continued recovery of these costs in future rates.

Competitive Transition Charges. These charges represent PECO's stranded costs that the PUC determined would be recoverable through regulated rates. These costs are related to the deregulation of the generation portion of the electric utility business in Pennsylvania. The CTC includes intangible transition property sold to the PETT, a subsidiary of PECO, in connection with the securitization of PECO's stranded cost recovery. These charges are being amortized through December 31, 2010 with a return on the unamortized balance of 10.75%.

Non-Pension Postretirement Benefits. These costs are the result of transitioning to SFAS No. 106 in 1993, which are recoverable in rates.

MGP Regulatory Asset. These costs represent estimated environmental remediation costs which are recoverable through regulated rates. PECO has identified 27 sites where former MGP activities have or may have resulted in site contamination.

DOE Facility Decommissioning. These costs represent PECO's share of recoverable decommissioning and decontamination costs of the DOE nuclear fuel enrichment facilities established by the National Energy Policy Act of 1992.

Recovery/Settlement of Regulatory Assets and Liabilities. 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. Therefore, they are earning a rate of return.

Deferred Energy Costs (Current Asset). These costs represent fuel costs recoverable under the purchase gas adjustment clause.

	December 31,	
	2003	2002
Accrued expenses		
Taxes accrued	**$ 304**	$ 420
Interest accrued	**247**	307
Other accrued expenses	**677**	627
Total	**$1,228**	$1,354

NOTE 21 • SEGMENT INFORMATION

Exelon operates in three business segments: Energy Delivery (ComEd and PECO), Generation and Enterprises. 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 interest in Sithe. Enterprises consists of competitive retail energy sales, energy and infrastructure services, a communications joint venture and other investments weighted towards the communications, energy services and retail services industries. In September 2003, Enterprises sold the electric construction and services, underground and telecom businesses of InfraSource, Inc. In December 2003, Enterprises signed agreements to sell the Chicago operations and the Aladdin thermal facility of Thermal and certain direct investments held by Enterprises. In 2004, Exelon Energy Company will become part of Generation, and Enterprises will continue to pursue opportunities to sell other Enterprises businesses.

An analysis and reconciliation of Exelon's business segment information to the respective information in the consolidated financial statements were as follows:

	Energy Delivery	Generation	Enterprises	Corporate	Intersegment Eliminations	Consolidated
Total revenues[(1)]:						
2003	$ 10,202	$ 8,135	$ 1,757	$ 402	$(4,684)	$ 15,812
2002	10,457	6,858	2,033	346	(4,739)	14,955
2001	10,171	6,826	2,292	341	(4,712)	14,918
Intersegment revenues:						
2003	$ 76	$ 4,125	$ 85	$ 398	$(4,684)	$ –
2002	76	4,227	97	341	(4,741)	–
2001	94	4,103	179	337	(4,713)	–
Depreciation and amortization:						
2003	$ 873	$ 199	$ 26	$ 28	$ –	$ 1,126
2002	978	276	55	31	–	1,340
2001	1,081	282	69	17	–	1,449
Operating expenses:						
2003	$ 7,579	$ 8,329	$ 1,919	$ 472	$(4,685)	$ 13,614
2002	7,597	6,349	2,047	402	(4,739)	11,656
2001	7,578	5,954	2,369	371	(4,716)	11,556
Interest expense:						
2003	$ 747	$ 88	$ 10	$ 45	$ (9)	$ 881
2002	854	75	14	74	(51)	966
2001	973	115	37	133	(151)	1,107
Income taxes:						
2003	$ 718	$ (179)	$ (81)	$ (127)	$ –	$ 331
2002	765	217	69	(53)	–	998
2001	703	327	(43)	(56)	–	931
Cumulative effect of changes in accounting principles:						
2003	$ 5	$ 108	$ (1)	$ –	$ –	$ 112
2002	–	13	(243)	–	–	(230)
2001	–	12	–	–	–	12
Net income/(loss):						
2003	$ 1,175	$ (133)	$ (136)	$ (1)	$ –	$ 905
2002	1,268	400	(178)	(50)	–	1,440
2001	1,022	524	(85)	(33)	–	1,428
Capital expenditures:						
2003	$ 962	$ 953	$ 14	$ 25	$ –	$ 1,954
2002	1,041	990	44	75	–	2,150
2001	1,105	858	61	64	–	2,088
Total assets:						
2003	$ 28,297	$ 14,764	$ 831	$ (1,951)	$ –	$ 41,941
2002	27,036	10,905	1,297	(1,369)	–	37,869
2001	26,590	8,145	1,743	(1,509)	–	34,969

(1) $439 million, $439 million and $373 million in utility taxes were included in Energy Delivery's revenues and expenses for 2003, 2002 and 2001, respectively.

Equity in earnings of AmerGen, prior to the acquisition of British Energy's 50% interest in December 2003, and Sithe of $49 million, $87 million, and $90 million for 2003, 2002, and 2001, respectively, are included in Generation's net income (loss). Equity in earnings (losses) of communications joint ventures and other investments of $(5) million, $3 million, and $(19) million for 2003, 2002, and 2001, respectively, are included in Enterprises' net loss. Equity in earnings (losses) of affordable housing investments of $(10) million, $(11) million and $(9) million for 2003, 2002 and 2001, respectively, are included in Corporate's net loss.

NOTE 22 • RELATED PARTY TRANSACTIONS

Exelon's financial statements reflect related-party transactions with unconsolidated affiliates as reflected in the tables below. Exelon accounted for its investment in AmerGen as an equity investment prior to the acquisition of British Energy's 50% interest in December 2003.

	For the Years Ended December 31,		
	2003	2002	2001
Purchased power from AmerGen(1)	**$382**	$273	$ 57
Interest income from AmerGen(2)	**1**	2	–
Interest income from Sithe(3)	**–**	–	2
Interest expense to Sithe(4)	**9**	2	–
Interest expense to PECO Energy Capital Trust IV(5)	**3**	–	–
Services provided to AmerGen(6)	**111**	70	80
Services provided to Sithe(7)	**–**	1	–
Services provided by Sithe(8)	**–**	13	–

Effective July 1, 2003, PECO Trust IV, a financing subsidiary created in May 2003, was deconsolidated from the financial statements in conjunction with the adoption of FIN No. 46. Additionally, effective December 31, 2003, ComEd Financing II, ComEd Financing III, ComEd Funding, LLC, ComEd Transitional Funding Trust, PECO Trust III and the PETT were deconsolidated from the financial statements of Exelon in conjunction with the adoption of FIN No. 46-R. As a result, over $6 billion of debt was recorded as debt to financing trusts within the Consolidated Balance Sheets as of December 31, 2003. Prior periods were not restated.

	December 31,	
	2003	2002
Receivables from affiliates (current)		
ComEd Transitional Funding Trust	**$ 9**	$ –
Investment in subsidiaries		
ComEd Funding LLC	**45**	–
ComEd Financing II	**8**	–
ComEd Financing III	**6**	–
PECO Energy Capital Corp	**16**	–
PECO Energy Capital Trust IV	**3**	–
Receivable from affiliates (noncurrent)		
ComEd Transitional Funding Trust	**9**	–
PECO Energy Transition Trust	**105**	–
Payables to affiliates (current)		
ComEd Financing II	**6**	–
ComEd Financing III	**4**	–
PECO Energy Capital Corp	**1**	–
PECO Energy Capital Trust III	**10**	–
Long-term debt to financing trusts (including due within one year)		
ComEd Transitional Funding Trust	**1,676**	–
ComEd Financing II	**155**	–
ComEd Financing III	**206**	–
PECO Energy Transition Trust	**3,849**	–
PECO Energy Capital Trust IV	**103**	–
PECO Energy Capital Trust III	**81**	–

	December 31, 2003	December 31, 2002
Net receivable from AmerGen[1,2,6]	**$ –**	$ 39
Net payable to Sithe[4,7,8]	**–**	7
Note receivable from Sithe[9]	**3**	–
Note payable to Sithe[4]	**90**	534
Note receivable from EXRES SHC, Inc.[10]	**92**	–

(1) Generation entered into PPAs dated June 26, 2003, December 18, 2001 and November 22, 1999 with AmerGen. Generation agreed to purchase 100% of the energy generated by Oyster Creek through April 9, 2009. Generation 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. Generation agreed to purchase all of the residual energy from Clinton not sold to Illinois Power through December 31, 2004. Currently, the residual output is approximately 31% of the total output of Clinton. See Note 2—Acquisitions and Dispositions for a description of Generation's purchase of British Energy's interest in AmerGen in December 2003.

(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. The principal balance of the loan was repaid in full in 2003.

(3) In August 2001, Exelon loaned Sithe $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 Exelon New England dated November 1, 2002, Generation issued a $534 million note to be paid in full on June 18, 2003 to Sithe. In June 2003, the principal of the note was increased $2 million, and the payment terms of the note were changed. Generation paid $446 million of principal in 2003 with the balance of the note to be paid by December 1, 2004, certain liquidity requirements or upon a change of control of Generation. Exelon has committed to pay down approximately $30 million of the note during the first six months of 2004 to fund Sithe's expected acquisition of the 40% of Sithe/Independence Power Partners, L.P. that it does not currently own. The note bears interest at the rate equal to LIBOR plus 0.875%.

(5) Effective July 1, 2003, PECO Energy Capital Trust IV was deconsolidated from the financial statements of Exelon in conjunction with FIN No. 46.

(6) Under a service agreement dated March 1, 1999, Generation provides AmerGen with certain operation and support services to the nuclear facilities owned by AmerGen. Generation is compensated for these services at cost.

(7) 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 at cost.

(8) Under a service agreement dated December 18, 2000, Sithe provides Generation certain fuel and project development services. Sithe is compensated for these services at cost. Under a service agreement dated November 1, 2002, Sithe provides Generation certain transition services related to the transition of the Exelon New England asset acquisition, which occurred in November 2002.

(9) In December 2003, Sithe received letter of credit proceeds of $3 million, which Generation was billed on behalf of Sithe.

(10) In connection with a series of transactions in November 2003 that restructured the ownership of Sithe (see Note 3—Sithe for additional information), Exelon received a $92 million note receivable from EXRES SHC, Inc, which holds the common stock of Sithe. Exelon owns 50% of EXRES SHC, Inc and accounts for its investment in EXRES SHC, Inc. as an equity investment.

NOTE 23 • 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 (Loss)		Income (Loss) Before the Cumulative Effect of Changes in Accounting Principles		Net Income (Loss)	
	2003	2002	**2003**	2002	**2003**	2002	**2003**	2002
Quarter ended:								
March 31	**$4,074**	$ 3,357	**$ 757**	$ 605	**$ 249**	$ 238	**$361**	$8
June 30	**3,721**	3,519	**800**	813	**372**	485	**372**	485
September 30	**4,441**	4,370	**(17)**	1,000	**(102)**	551	**(102)**	551
December 31	**3,576**	3,709	**658**	881	**274**	396	**274**	396

	Average Basic Shares Outstanding (in millions)		Earnings (Loss) per Basic Share Before the Cumulative Effect of Changes in Accounting Principles		Net Income (Loss) per Basic Share	
	2003	2002	**2003**	2002	**2003**	2002
Quarter ended:						
March 31	**324**	321	**$ 0.77**	$0.74	**$1.11**	$0.02
June 30	**325**	322	**1.14**	1.50	**1.14**	1.50
September 30	**326**	323	**(0.31)**	1.71	**(0.31)**	1.71
December 31	**328**	323	**0.84**	1.23	**0.84**	1.23

	Average Diluted Shares Outstanding (in millions)		Earnings (Loss) per Diluted Share Before the Cumulative Effect of Changes in Accounting Principles		Net Income (Loss) per Diluted Share	
	2003	2002	**2003**	2002	**2003**	2002
Quarter ended:						
March 31	**326**	323	**$ 0.77**	$0.73	**$ 1.11**	$0.02
June 30	**327**	324	**1.14**	1.50	**1.14**	1.50
September 30	**326**	324	**(0.31)**	1.70	**(0.31)**	1.70
December 31	**331**	325	**0.83**	1.22	**0.83**	1.22

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

	2003				2002			
	Fourth Quarter	Third Quarter	Second Quarter	First Quarter	Fourth Quarter	Third Quarter	Second Quarter	First Quarter
High price	**$66.62**	**$63.95**	**$60.91**	**$ 55.20**	$53.06	$ 52.83	$56.99	$53.88
Low price	**60.95**	**54.18**	**49.65**	**46.08**	42.38	37.85	50.10	45.90
Close	**66.36**	**63.50**	**59.81**	**50.41**	52.77	47.50	52.30	52.97
Dividends	**0.50**	**0.50**	**0.46**	**0.46**	0.44	0.44	0.44	0.44

NOTE 24 • SUBSEQUENT EVENTS

On January 15, 2004, ComEd redeemed at maturity $26 million of its 5.30% pollution control bonds collateralized by first mortgage bonds. The proceeds from an issuance of $20 million of pollution control bonds in December 2003 and available cash were used to redeem these bonds.

On January 15, 2004, ComEd redeemed at maturity $150 million of its 7.375% notes.

In January 2004, the counterparties to the interest-rate swap agreements with Boston Generating, which had effectively fixed the interest rate on $861 million of notional principal related to the Boston Generating Facility, terminated the interest-rate swaps. The total net value of these interest-rate swaps as of the respective termination dates was $82 million, which is a net payable to the counterparties.

On January 27, 2004, the Board of Directors of Exelon declared a regular quarterly dividend of $0.55 per share on Exelon's common stock and approved a 2-for-1 stock split of Exelon's common stock. The stock split will be effective after the receipt of all necessary regulatory approvals and the filing of an amendment to Exelon's articles of incorporation with the Commonwealth of Pennsylvania and notification to the New York Stock Exchange. No record date for the stock split has been set. As the stock split is not effective, the share and per-share amounts included in Exelon's consolidated financial statements have not been adjusted to reflect the stock split.

The following table presents average shares of common stock outstanding (basic and diluted), earnings per average common share (basic and diluted) and dividends per common share for the years ended December 31, 2003, 2002 and 2001 on a pro forma basis as if the stock split had been reflected in the accompanying consolidated financial statements.

	For the Years Ended December 31,		
	2003	2002	2001
Pro forma average shares of common stock outstanding			
Basic	**651**	645	641
Diluted	**657**	649	645
Pro forma earnings per average common share–basic:			
Income before cumulative effect of changes in accounting principles	**$ 1.22**	$ 2.59	$ 2.21
Cumulative effect of changes in accounting principles	**0.17**	(0.36)	0.02
Net income	**$ 1.39**	$ 2.23	$ 2.23
Pro forma earnings per average common share–diluted:			
Income before cumulative effect of changes in accounting principles	**$ 1.21**	$ 2.57	$ 2.19
Cumulative effect of changes in accounting principles	**0.17**	(0.35)	0.02
Net income	**$ 1.38**	$ 2.22	$ 2.21
Pro forma dividends per common share	**$0.96**	$ 0.88	$ 0.91

CORPORATE PROFILE

Exelon Corporation is one of the nation's largest electric utilities with approximately 5.1 million electric customers in northern Illinois and southeastern Pennsylvania and approximately 460,000 gas customers in the Philadelphia area. The Company has one of the industry's largest portfolios of electricity generation capacity, with a nationwide reach and strong positions in the Midwest and Mid-Atlantic. The Company also has holdings in such competitive businesses as energy and energy services. Exelon's market capitalization at the end of 2003 was $21.8 billion. Headquartered in Chicago, Exelon trades on the NYSE under the ticker EXC.

INVESTOR AND GENERAL INFORMATION

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

Independent Public Accountants
PricewaterhouseCoopers LLP

Website
www.exeloncorp.com

New York Stock Exchange Listing
EXC

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

Should you have questions or requests concerning your account, payment of dividends, the dividend reinvestment plan or transfer of stock, you may call toll-free, 1.866.530.8108. You may also mail your inquiry to Exelon Corporation c/o EquiServe Trust Company, N.A., Post Office Box 43069, Providence, RI 02940-3069. If you prefer, EquiServe provides walk-in service to Exelon shareholders at One North State Street, Eleventh Floor, Chicago, Illinois.

The Company had approximately 170,000 holders of record of its common stock as of December 31, 2003.

The 2003 Form 10-K Annual Report to the Securities and Exchange Commission was filed on February 20, 2004. To obtain a copy without charge, write to Katherine K. Combs, Vice President and Corporate Secretary, Exelon Corporation, Post Office Box 805398, Chicago, Illinois 60680-5398.

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

Forward Looking Statements
Exelon's 2003 Annual Report to Shareholders contains certain forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. These statements are based on management's current expectations and are subject to uncertainty and changes in circumstances. Actual results may vary materially from the expectations contained herein. The forward-looking statements herein include statements about future financial and operating results of Exelon. Economic, business, competitive and/or regulatory factors affecting Exelon's businesses generally could cause actual results to differ materially from those described herein. For a discussion of the factors that could cause actual results to differ materially, please see "Management's Discussion and Analysis of Financial Condition and Results of Operations – Business Outlook and the Challenges In Managing Our Business" in this Annual Report, "Risk Factors" in Exelon's Registration Statement on Form S-3, Reg. No. 333-108546, and Exelon's other filings with the Securities and Exchange Commission. Readers are cautioned not to place undue reliance on these forward-looking statements, which speak only as of the date of this document. Exelon does not undertake any obligation to publicly release any revisions to these forward-looking statements to reflect events or circumstances after the date of the Annual Report.

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

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