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FirstEnergy

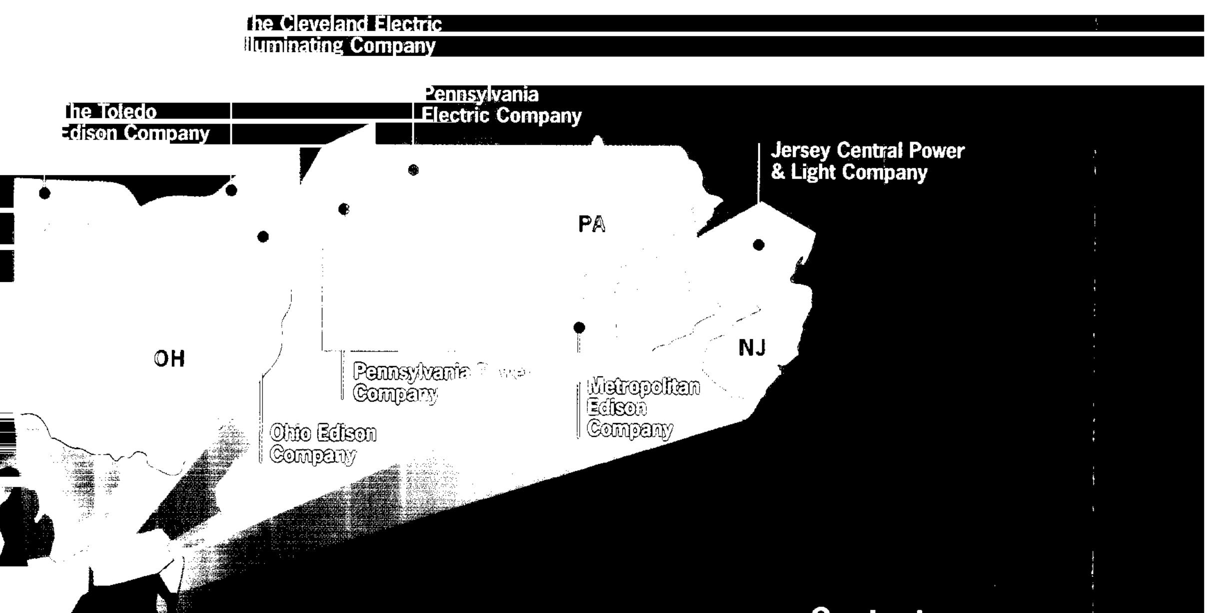
2004 Annual Report

BUILDING ON OUR PROGRESS

Corporate Profile

FirstEnergy is a diversified energy company headquartered in Akron, Ohio. Its subsidiaries and affiliates are involved in the generation, transmission and distribution of electricity, as well as energy management and other energy-related services. Its seven electric utility operating companies comprise the nation's fifth largest investor-owned electric system, based on 4.4 million customers served within a 36,100-square-mile area of Ohio, Pennsylvania and New Jersey.

Electric Utility Operating Companies



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Financial Highlights

(Dollars in thousands, except per share amounts)

	2004	2003
Total revenues	**$12,453,046**	$11,674,888
Income before discontinued operations and cumulative effect of accounting change*	**$873,779**	$424,249
Net income	**$878,175**	$422,764
Basic earnings per common share:		
Before discontinued operations and cumulative effect of accounting change	**$2.67**	$1.40
After discontinued operations and cumulative effect of accounting change	**$2.68**	$1.39
Diluted earnings per common share:		
Before discontinued operations and cumulative effect of accounting change	**$2.66**	$1.40
After discontinued operations and cumulative effect of accounting change	**$2.67**	$1.39
Dividends declared per common share**	**$1.9125**	$1.50
Book value per common share	**$26.20**	$25.35
Net cash from operations	**$1,876,850**	$1,754,855

* *The 2004 and 2003 discontinued operations are described in Note 2(J) to the Consolidated Financial Statements. The 2003 accounting change is described in Note 2(K) to the Consolidated Financial Statements.*

** *A quarterly dividend of $0.4125 was declared in 2004 payable March 1, 2005, increasing the indicated annual dividend rate from $1.50 to $1.65 per share.*

The following analysis reconciles basic earnings per share of common stock in 2004 and 2003 computed under generally accepted accounting principles (GAAP) to adjusted basic earnings per share excluding unusual items in both years (non-GAAP)*.

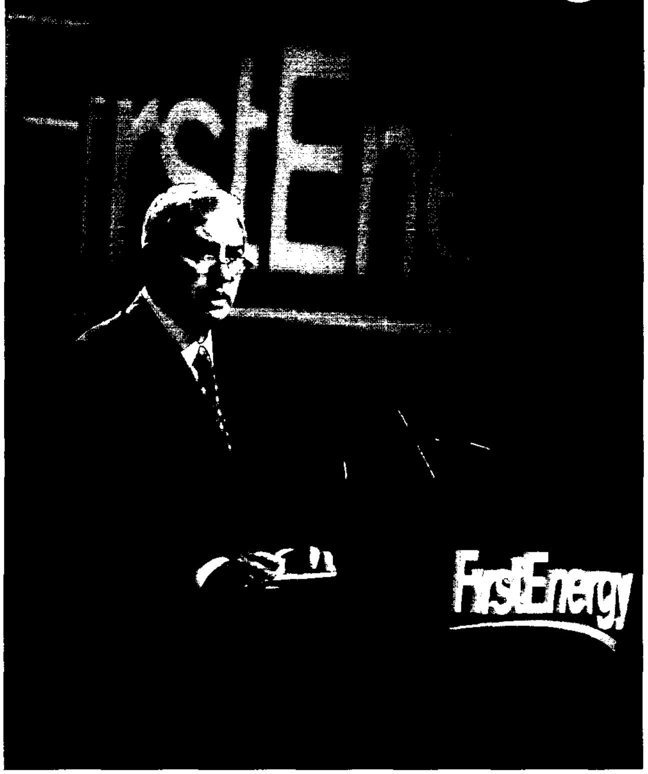
	2004	2003
Adjusted basic earnings per share:		
Basic earnings per share (GAAP)	**$2.68**	$1.39
Claim settlement	—	(0.33)
Davis-Besse extended outage impacts	**0.12**	0.56
Rate case disallowance	—	0.36
Asset impairments	**0.19**	0.41
Litigation settlement	**0.03**	—
Discontinued international operations	—	0.33
Cumulative effect of accounting change	—	(0.33)
Other unusual items (see Management's Discussion)	**0.01**	0.03
Adjusted basic earnings per share (non-GAAP)	**$3.03**	$2.42

* *Generally, a non-GAAP financial measure is a numerical measure of a company's historical or future financial performance, financial position, or cash flows that either excludes or includes amounts that are not normally excluded or included in the most directly comparable measure calculated and presented in accordance with GAAP.*

Forward-Looking Statements

This annual report includes forward-looking statements based on information currently available to management. Such statements are subject to certain risks and uncertainties. These statements typically contain, but are not limited to, the terms "anticipate," "potential," "expect," "believe," "estimate" and similar words. Actual results may differ materially due to the speed and nature of increased competition and deregulation in the electric utility industry, economic or weather conditions affecting future sales and margins, changes in markets for energy services, changing energy and commodity market prices, replacement power costs being higher than anticipated or inadequately hedged, maintenance costs being higher than anticipated, legislative and regulatory changes (including revised environmental requirements), the receipt of approval from and entry of a final order by the U.S. District Court, Southern District of Ohio, on the pending settlement agreement resolving the New Source Review litigation and the uncertainty of the timing and amounts of the capital expenditures (including that such amounts could be higher than anticipated) related to this settlement, adverse regulatory or legal decisions and outcomes (including revocation of necessary licenses or operating permits, fines or other enforcement actions and remedies) of government investigations, including by the Securities and Exchange Commission, the United States Attorney's Office and the Nuclear Regulatory Commission as disclosed in our Securities and Exchange Commission filings, generally, and with respect to the Davis-Besse Nuclear Power Station outage in particular, the availability and cost of capital, the continuing availability and operation of generating units, our inability to accomplish or realize anticipated benefits from strategic goals, our ability to improve electric commodity margins and to experience growth in the distribution business, our ability to access the public securities and other capital markets, further investigation into the causes of the August 14, 2003 regional power outage and the outcome, cost and other effects of present and potential legal and administrative proceedings and claims related to the outage, the final outcome in the proceeding related to FirstEnergy's Application for a Rate Stabilization Plan in Ohio, the risks and other factors discussed from time to time in our Securities and Exchange Commission filings, and other similar factors. We expressly disclaim any current intention to update any forward-looking statements contained herein as a result of new information, future events, or otherwise.

Message To Shareholders



We made significant progress in 2004. We positioned ourselves for continued success in the years ahead and placed many of the challenges of the past several years behind us. Our key accomplishments included:

- Returning the Davis-Besse Nuclear Power Station to safe and reliable operation
- Enhancing the reliability of our service to customers
- Achieving record performance by our generation fleet
- *Gaining approval for our Rate Stabilization* Plan in Ohio

Our financial performance in 2004 was strong, particularly in the key areas of earnings, cash flow and debt reduction. We delivered basic earnings per share of $2.91 on a non-GAAP* basis, exceeding our guidance to the financial community of $2.70 to $2.85. Net cash from operating activities also remained strong at $1.88 billion – up from $1.75 billion in 2003 – and we met our target to reduce debt by $1 billion.

We also delivered to shareholders a total annualized return – a measure of stock price appreciation plus reinvested dividends – of 16.6 percent in 2004. This brings our five-year annualized total return to 17.1 percent, ranking us 17th among the 64 U.S. investor-owned electric utilities that comprise the Edison Electric Institute's (EEI) index.

Our performance and outlook supported your Board of Directors' action to increase the common stock dividend by 10 percent, the first increase since the Company was created in 1997.

Operational Results

To support our ongoing focus on enhancing service reliability, last year we spent $940 million on capital improvement projects and operating and maintenance activities in our energy delivery area. In 2005, we expect to spend more than $1 billion, including expenditures on a wide range of system enhancements. Our plans include upgrading and renewing our transmission and distribution facilities, improving relaying and protection to minimize service interruptions, installing remote control and automation to ensure timely restoration when service interruptions occur, and adding new technologies such as advance lightning detection, which enables our system to better protect itself. We are investing in our critical infrastructure with the clear goal of strengthening our reliability and improving customer service.

In another effort to improve service reliability, we modified our existing information technologies to develop a leading-edge capability to track outage history down to the individual customer. Scheduled for full implementation in June 2005, this system can pinpoint locations and causes of problems, enabling us to target our investments in improvements that enhance reliability and customer satisfaction.

Our storm restoration process proved its effectiveness in response to a major storm event in May of 2004, as well as during two ice storms this past winter. All three events caused interruptions to hundreds of thousands of customers. Despite severe damage to our system, we restored service to all customers faster than at any time in our history, with 80 percent back in service within the first 24 hours.

In addition to the storm process work at home, some 400 volunteer employees traveled to Florida and Alabama to assist in restoring service in the aftermath of the multiple hurricanes that ravaged those areas in 2004. Along with the hundreds of letters of thanks we received from grateful residents, we are proud that the hard work and dedication of our employees were further recognized by EEI, which named FirstEnergy a recipient of the EEI Emergency Assistance Award.

"Our financial performance in 2004 was strong, particularly in the key areas of earnings, cash flow and debt reduction."

Another highlight of 2004 was the performance of our generation fleet, which produced a record 76 billion kilowatt-hours (KWH). The fossil generation fleet provided solid performance, producing more than 45 billion KWH, while our nuclear fleet produced a record 29.9 billion KWH.

Our largest coal-based generating facility, the 2,360-megawatt (MW) Bruce Mansfield Plant, led the way for our fossil fleet. The plant set a generation record of more than 18 billion KWH, topping its previous record by more than 2 billion KWH. Its 88.9 percent capacity factor – the actual amount of electricity generated compared with the amount that could be generated at full power for the year – placed its performance in the industry's top decile. In the fall of 2005, we expect to initiate the plant's first capacity expansion program with a planned upgrade of Unit 1's turbine, which should increase its output by about 50 MW. Similar upgrades are planned for units 2 and 3 in coming years, which would enable the plant to produce an additional 1 billion KWH annually.

Turning to our nuclear fleet, we completed a major reorganization of our FirstEnergy Nuclear Operating Company (FENOC) subsidiary that added experienced nuclear managers and centralized managerial oversight of our nuclear units; established a uniform organizational structure within the plants; and began implementing common procedures and practices across the fleet. The capacity factor of our nuclear fleet reached 90.6 percent, a historic high, even with Davis-Besse's return to service in March. Beaver Valley earned a Performance Improvement Award from the Institute of Nuclear Power Operations, and its Unit 2 has operated for more than 500 consecutive days, establishing a plant record for continuous operation. More important, the fleet posted a record low U.S. Occupational Safety and Health Administration (OSHA) Reportable Incident Rate, led by the Perry Plant, where employees have worked 8.9 million hours without a lost-time accident.

In 2004 and early 2005, we also reached multi-year labor agreements with 8 union locals representing more than 3,250 workers. Employees represented by these unions have joined our new health care plan, providing them with competitive benefits while enabling the Company to better manage the increasing costs of health care.

We accomplished these solid results while maintaining our focus on safety. In 2004, we achieved a Company-wide OSHA rate of 1.44 incidents per 100 employees, a 9-percent reduction compared with 2003 results. This performance typically would rank us in the top decile of our industry, although EEI has not yet published results for 2004.

We expect to continue enhancing our operational performance under the leadership of our Executive Vice President and Chief Operating Officer, Richard R. Grigg, who joined the Company in August. With 34 years of industry experience, most recently as president and chief executive officer of WE Generation, Mr. Grigg leads our Energy Delivery, Fossil Generation and Commodity Operations business units.

Protecting the Environment

We also delivered strong results in our efforts to protect the environment. Last year, 40 percent of our electricity was produced from our non-emitting nuclear fleet. We also achieved continuing emission reductions from our coal-based plants. Since 1990, we've reduced nitrogen oxides (NOx) by more than 60 percent and sulfur dioxide (SO_2) by nearly one-half.

In the past three years, we've spent $196 million to install selective catalytic reduction equipment on all three units of our scrubber-equipped Bruce Mansfield Plant. This equipment is designed to reduce NOx emissions, a precursor to ozone, by more than 8,000 tons during the summer ozone season.

And, in March of this year, we announced plans to significantly reduce emissions of NOx and SO_2 from current levels at several of our power plants as part of a settlement agreement that resolves all issues related to the New Source Review case involving our W. H. Sammis Plant. Under the agreement, we will install additional environmental controls at Sammis, as well as at a number of our other power plants. For example, in the fall of 2005, we will begin a three-year project to improve the existing scrubbers at the Mansfield Plant as part of our plans to further reduce SO_2 emissions.

"Last year, 40 percent of our electricity was produced from our non-emitting nuclear fleet."

The new environmental controls also will provide the foundation for achieving the emission reductions we will be making to comply with the U.S. Environmental Protection Agency's recently announced Clean Air Interstate and Clean Air Mercury rules.

We're working on the development of cost-effective, new technologies to help achieve these additional reductions. One promising new technology is the Electro-Catalytic Oxidation™ (ECO) system developed by Powerspan Corp. and currently being demonstrated at our R. E. Burger Plant. This technology is designed to reduce NOx, SO_2, fine particulates and mercury emissions, and, if successful, will be available for commercial application at coal-based power plants across the country.

Setting the Stage for the Future

As a result of our successful efforts to reduce debt, control costs and enhance cash flow, your Board declared a new quarterly dividend of 41.25 cents per share of outstanding common stock, which represents a 10-percent increase over the previous quarterly rate. The new indicated annual dividend is $1.65 per share, up from $1.50 per share.

Your Board also adopted a dividend policy that targets sustainable annual dividend increases after 2005, generally reflecting an annual growth rate of 4 to 5 percent, and an earnings payout ratio generally within the range of 50 to 60 percent. The Board will continue to review FirstEnergy's dividend policy regularly. The amount and timing of all dividend payments are subject to the Board's consideration of business conditions, results of operations, financial condition and other factors.

We also enhanced the value of your investment by retiring, refinancing or restructuring more than $2.8 billion in long-term debt last year, which reduced interest costs by approximately $54 million in 2004.

"We expect to fill approximately 1,600 positions system-wide in the next two years..."

The $1 billion in debt we eliminated brings the total to $3 billion since 2002, reducing our adjusted debt-to-capitalization ratio to 57 percent from 65 percent three years ago. At the same time, we were able to resolve funding issues related to our pension program for the next several years by making a $500-million contribution to the plan in September. Even so, the total capacity of our primary credit facilities stood at $2.3 billion at year-end.

Another significant accomplishment in 2004 – for our customers and for your Company – was gaining approval by the Public Utilities Commission of Ohio (PUCO) of our Rate Stabilization Plan. The plan will provide a longer period of predictable revenue from our three Ohio electric utility operating companies. In addition, it will provide customers with more stable generation prices for three years following the end of Ohio's market development period on December 31, 2005, under the state's electricity deregulation law. An independent auction conducted last fall at the direction of the PUCO confirmed that the price we offered under the plan was competitive.

We addressed another key challenge last year with an agreement that resolves all pending private securities and derivative lawsuits related to the extended outage at Davis-Besse; the August 14, 2003, regional power outage; and financial restatements related to changed accounting treatments for transition assets being recovered in Ohio. Four customer damage cases related to the regional power outage remain in various venues in Ohio and New York.

Preparing for Our Workforce of the Future

We're also addressing a significant issue facing companies throughout the U.S. – the need to replace experienced employees who will retire over the next several years. We expect to fill approximately 1,600 positions system-wide in the next two years alone – some through promotions and reassignments, but primarily through aggressive efforts to recruit talented and highly motivated people from outside our Company who will help ensure our future success.

The hiring will occur across the Company, including generating plant and utility workers, as well as an array of technical and professional positions.

Our business requires considerable skills and continuous attention to safety by our employees. We will work to ensure that new employees receive on-the-job training, as well as ongoing mentoring from the experienced and knowledgeable employees we're fortunate to have on staff now.

Building on Our Progress

Executing our plan was critical to our progress in 2004, and will serve as a solid foundation for future growth. Certainly, challenges remain. However, I'm confident that, through the hard work of our skilled and dedicated employees and your continued support, we will build on that progress and enhance the long-term value of your investment.

Sincerely,

Anthony J. Alexander

Anthony J. Alexander
President and Chief Executive Officer
March 18, 2005

* *This letter to shareholders contains non-GAAP earnings per share. This non-GAAP measure excludes amounts that are not normally excluded in the most directly comparable measure calculated and presented in accordance with accounting principles generally accepted in the United States (GAAP). A reconciliation of GAAP basic earnings per share ($2.68 in 2004) to non-GAAP basic earnings per share ($3.03 in 2004, before the reduction of $0.12 per share for Davis-Besse impacts) can be found in the accompanying Management's Discussion and Analysis of Results of Operations and Financial Condition on page 13.*

FirstEnergy Board of Directors

Dear Shareholders:

On behalf of your Board of Directors, I would like to take this opportunity to thank our management team and all employees for a year of significant progress and achievement. During the year, your Board also took a number of steps to enhance our responsiveness to the shareholders we are privileged to serve.

For example, we reviewed and strengthened our overall corporate governance practices – taking steps that included updating charters and policies, separating the functions of chairman and CEO, and eliminating staggered terms so that all directors will be elected annually when their current terms expire.

We also elected to eliminate the Shareholder Rights Plan – a move that a majority of our shareholders supported – and we agreed to put any future plan to a shareholder vote within one year of adoption.

These and other actions have helped make your Company a leader in an important corporate governance measurement developed by Institutional Shareholder Services (ISS) – the Corporate Governance Quotient (CGQ). At year-end, our CGQ index ranking was 96.9, reflecting the percentage of companies in the S&P 500 Index we outperformed. Our industry ranking of 95.7 reflected our performance against companies in ISS's utility group.

In addition, we were pleased to raise your Company's common-stock dividend – the first increase since FirstEnergy was formed in 1997. And, we adopted a policy that should provide for dividend growth in the future.

On a more personal note, I join the Board in expressing our appreciation to recently retired Director John M. Pietruski for his many years of service to GPU, Inc., and FirstEnergy. Also, we welcome Ernest J. Novak, Jr., who was elected to the Board in May, and Wesley M. Taylor, who was elected in September. Mr. Novak, retired managing partner of the Cleveland office of Ernst & Young LLP, is serving as your Board's designated financial expert.

We are confident that these and other changes represent the best interests of our shareholders, and we appreciate your continued support as we consider new ways to enhance the value of your investment in FirstEnergy.

Sincerely,

George M. Smart

George M. Smart
Chairman of the Board

Paul T. Addison

Anthony J. Alexander

Paul J. Powers

Catherine A. Rein

Paul T. Addison, 58
Retired, formerly Managing Director in the Utilities Department of Salomon Smith Barney (Citigroup). Member, Audit and Finance Committees. Director of FirstEnergy Corp. since 2003.

Anthony J. Alexander, 53
President and Chief Executive Officer of FirstEnergy Corp. Director of FirstEnergy Corp. since 2002.

Dr. Carol A. Cartwright, 63
President, Kent State University. Chair, Corporate Governance Committee; Member, Compensation Committee. Director of FirstEnergy Corp. since 1997 and of Ohio Edison from 1992-1997.

William T. Cottle, 59
Retired, formerly Chairman of the Board, President and Chief Executive Officer of STP Nuclear Operating Company. Chair, Nuclear Committee; Member, Corporate Governance Committee. Director of FirstEnergy Corp. since 2003.


Dr. Carol A. Cartwright


William T. Cottle


Russell W. Maier


Ernest J. Novak, Jr.


Robert N. Pokelwaldt


Robert C. Savage


George M. Smart


Wesley M. Taylor


Jesse T. Williams, Sr.


Dr. Patricia K. Woolf

Russell W. Maier, 68
President and Chief Executive Officer of Michigan Seamless Tube LLC. Member, Compensation and Nuclear Committees. Director of FirstEnergy Corp. since 1997 and of Ohio Edison from 1995-1997.

Ernest J. Novak, Jr., 60
Retired, formerly Managing Partner of the Cleveland office of Ernst & Young LLP. Member, Audit and Finance Committees. Director of FirstEnergy Corp. since 2004.

Robert N. Pokelwaldt, 68
Retired, formerly Chairman of the Board and Chief Executive Officer of YORK International Corporation. Member, Audit and Finance Committees. Director of FirstEnergy Corp. since 2001 and of the former GPU, Inc., from 2000-2001.

Paul J. Powers, 70
Retired, formerly Chairman of the Board and Chief Executive Officer of Commercial Intertech Corp. Chair, Finance Committee; Member, Compensation Committee. Director of FirstEnergy Corp. since 1997 and of Ohio Edison from 1992-1997.

Catherine A. Rein, 62
Senior Executive Vice President and Chief Administrative Officer of Metropolitan Life Insurance Company. Chair, Compensation Committee; Member, Audit Committee. Director of FirstEnergy Corp. since 2001 and of the former GPU, Inc., from 1989-2001.

Robert C. Savage, 67
Chairman of the Board of Savage & Associates, Inc. Member, Finance and Nuclear Committees. Director of FirstEnergy Corp. since 1997 and of the former Centerior Energy Corporation from 1990-1997.

George M. Smart, 59
Non-executive Chairman of the FirstEnergy Board of Directors. Retired, formerly President of Sonoco-Phoenix, Inc. Chair, Audit Committee. Director of FirstEnergy Corp. since 1997 and of Ohio Edison from 1988-1997.

Wesley M. Taylor, 62
Retired, formerly President of TXU Generation. Member, Nuclear Committee. Director of FirstEnergy Corp. since 2004.

Jesse T. Williams, Sr., 65
Retired, formerly Vice President of Human Resources Policy, Employment Practices and Systems of The Goodyear Tire & Rubber Company. Member, Corporate Governance and Nuclear Committees. Director of FirstEnergy Corp. since 1997 and of Ohio Edison from 1992-1997.

Dr. Patricia K. Woolf, 70
Consultant, author, and former Lecturer in the Department of Molecular Biology at Princeton University. Member, Corporate Governance and Nuclear Committees. Director of FirstEnergy Corp. since 2001 and of the former GPU, Inc., from 1983-2001.

FirstEnergy Officers

FirstEnergy Corp.

Anthony J. Alexander
President and Chief Executive Officer

Richard R. Grigg
Executive Vice President and Chief Operating Officer

Richard H. Marsh*
Senior Vice President and Chief Financial Officer

Leila L. Vespoli*
Senior Vice President and General Counsel

Harvey L. Wagner
Vice President, Controller and Chief Accounting Officer

David W. Whitehead
Corporate Secretary

Thomas C. Navin*
Treasurer

Paulette R. Chatman*
Assistant Controller

Jeffrey R. Kalata*
Assistant Controller

Randy Scilla*
Assistant Treasurer

Jacqueline S. Cooper*
Assistant Corporate Secretary

Edward J. Udovich*
Assistant Corporate Secretary

* *Also holds the same title with FirstEnergy Service Company, FirstEnergy Solutions Corp. and FirstEnergy Nuclear Operating Company*

FirstEnergy Service Company

Anthony J. Alexander
President and Chief Executive Officer

Richard R. Grigg
Executive Vice President and Chief Operating Officer

Mark T. Clark
Senior Vice President

Douglas S. Elliott
Senior Vice President

Charles E. Jones
Senior Vice President

Kevin J. Keough
Senior Vice President

Carole B. Snyder
Senior Vice President

Thomas M. Welsh
Senior Vice President

David M. Blank
Vice President

Mary Beth Carroll
Vice President

Lynn M. Cavalier
Vice President

Kathryn W. Dindo
Vice President and Chief Risk Officer

Ralph J. DiNicola
Vice President

Michael J. Dowling
Vice President and Chief Procurement Officer

Bradley S. Ewing
Vice President

Terrance G. Howson
Vice President

Ali Jamshidi
Vice President

Mark A. Julian
Vice President

David C. Luff
Vice President

Stanley F. Szwed
Vice President

Bradford F. Tobin
Vice President and Chief Information Officer

Harvey L. Wagner
Vice President and Controller

David W. Whitehead
Vice President, Corporate Secretary and Chief Ethics Officer

Lisa S. Wilson
Assistant Controller

FirstEnergy Solutions Corp.

Guy L. Pipitone
President

Charles D. Lasky
Vice President

Alfred G. Roth
Vice President

Donald R. Schneider
Vice President

Trent A. Smith
Vice President

Daniel V. Steen
Vice President

Harvey L. Wagner
Vice President and Controller

David W. Whitehead
Corporate Secretary

FirstEnergy Nuclear Operating Company

Anthony J. Alexander
Chief Executive Officer

Gary R. Leidich
President and Chief Nuclear Officer

Joseph J. Hagan
Senior Vice President

Lew W. Myers
Chief Operating Officer

Mark B. Bezilla
Vice President, Davis-Besse

Richard L. Anderson
Vice President, Perry

L. William Pearce
Vice President, Beaver Valley

Jeanine M. Rinckel
Vice President, Oversight

Harvey L. Wagner
Vice President and Controller

David W. Whitehead
Corporate Secretary

FirstEnergy Regional Operations Management

Dennis M. Chack
Regional President The Cleveland Electric Illuminating Company

Thomas A. Clark
Regional President Ohio Edison Company

James M. Murray
Regional President The Toledo Edison Company

Stephen E. Morgan
President Jersey Central Power & Light Company

Donald M. Lynch
Regional President Jersey Central Power & Light Company

Steven E. Strah
Regional President Jersey Central Power & Light Company

Ronald P. Lantzy
Regional President Metropolitan Edison Company

John E. Paganie
Regional President Pennsylvania Electric Company

Glossary of Terms

The following abbreviations and acronyms are used in this report to identify FirstEnergy Corp. and its current and former subsidiaries:

ATSI	American Transmission Systems, Inc., owns and operates transmission facilities
Avon	Avon Energy Partners Holdings
CEI	The Cleveland Electric Illuminating Company, an Ohio electric utility operating subsidiary
CFC	Centerior Funding Corporation, a wholly owned finance subsidiary of CEI
Companies	OE, CEI, TE, Penn, JCP&L, Met-Ed and Penelec
Emdersa	Empresa Distribuidora Electrica Regional S.A.
EUOC	Electric Utility Operating Companies (OE, CEI, TE, Penn, JCP&L, Met-Ed, Penelec, and ATSI)
FENOC	FirstEnergy Nuclear Operating Company, operates nuclear generating facilities
FES	FirstEnergy Solutions Corp., provides energy-related products and services
FESC	FirstEnergy Service Company, provides legal, financial, and other corporate support services
FGCO	FirstEnergy Generation Corp., operates nonnuclear generating facilities
FirstCom	First Communications, LLC, provides local and long-distance telephone service
FirstEnergy	FirstEnergy Corp., a registered public utility holding company
FSG	FirstEnergy Facilities Services Group, LLC, the parent company of several heating, ventilation, air conditioning and energy management companies
GLEP	Great Lakes Energy Partners, LLC, an oil and natural gas exploration and production venture
GPU	GPU, Inc., former parent of JCP&L, Met-Ed and Penelec, which merged with FirstEnergy on November 7, 2001
GPU Capital	GPU Capital, Inc., owned and operated electric distribution systems in foreign countries
GPU Power	GPU Power, Inc., owned and operated generation facilities in foreign countries
JCP&L	Jersey Central Power & Light Company, a New Jersey electric utility operating subsidiary
MARBEL	MARBEL Energy Corporation, previously held FirstEnergy's interest in GLEP
Met-Ed	Metropolitan Edison Company, a Pennsylvania electric utility operating subsidiary
MYR	MYR Group, Inc., a utility infrastructure construction service company
NEO	Northeast Ohio Natural Gas Corp., formerly a MARBEL subsidiary
OE	Ohio Edison Company, an Ohio electric utility operating subsidiary
Ohio Companies	CEI, OE and TE
Penelec	Pennsylvania Electric Company, a Pennsylvania electric utility operating subsidiary
Penn	Pennsylvania Power Company, a Pennsylvania electric utility operating subsidiary of OE
PNBV	PNBV Capital Trust, a special purpose entity created by OE in 1996
Shippingport	Shippingport Capital Trust, a special purpose entity created by CEI and TE in 1997
TE	The Toledo Edison Company, an Ohio electric utility operating subsidiary
TEBSA	Termobarranquilla S.A., Empresa de Servicios Publicos

The following abbreviations and acronyms are used to identify frequently used terms in this report:

ALJ	Administrative Law Judge
AOCL	Accumulated Other Comprehensive Loss
APB	Accounting Principles Board
APB 25	APB Opinion No. 25, "Accounting for Stock Issued to Employees"
APB 29	APB Opinion No. 29, "Accounting for Nonmonetary Transactions"
ARB 43	Accounting Research Bulletin No. 43, "Restatement and Revision of Accounting Research Bulletins"
ARO	Asset Retirement Obligation
ASLB	Atomic Safety and Licensing Board
BGS	Basic Generation Service
CO_2	Carbon Dioxide
CTC	Competitive Transition Charge
ECAR	East Central Area Reliability Coordination Agreement
EITF	Emerging Issues Task Force
EITF 03-1	EITF Issue No. 03-1, "The Meaning of Other-Than-Temporary and Its Application to Certain Investments"
EITF 03-16	EITF Issue No. 03-16, "Accounting for Investments in Limited Liability Companies"
EITF 97-4	EITF Issue No. 97-4 "Deregulation of the Pricing of Electricity - Issues Related to the Application of FASB Statements No. 71 and 101"
EITF 99-19	EITF Issue No. 99-19, "Reporting Revenue Gross as a Principal versus Net as an Agent"
EPA	Environmental Protection Agency
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FIN	FASB Interpretation
FIN 46R	FIN 46 (revised December 2003), "Consolidation of Variable Interest Entities"
FMB	First Mortgage Bonds
FSP	FASB Staff Position
FSP EITF 03-1-1	FASB Staff Position No. EITF Issue 03-1-1, "Effective Date of Paragraphs 10-20 of EITF Issue No. 03-1, The Meaning of Other-Than-Temporary Impairment and Its Application to Certain Investments"
FSP 106-1	FASB Staff Position No.106-1, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003"
FSP 106-2	FASB Staff Position No.106-2, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003"
FSP 109-1	FASB Staff Position No. 109-1, "Application of FASB Statement No. 109, Accounting for Income Taxes, to the Tax Deduction and Qualified Production Activities provided by the American Jobs Creation Act of 2004"
GAAP	Accounting Principles Generally Accepted in the United States
HVAC	Heating, Ventilation and Air-conditioning
IRS	Internal Revenue Service
ISO	Independent System Operator
KWH	Kilowatt-hours
LOC	Letter of Credit
MACT	Maximum Achievable Control Technologies
Medicare Act	Medicare Prescription Drug, Improvement and Modernization Act of 2003
MISO	Midwest Independent System Transmission Operator, Inc.
Moody's	Moody's Investors Service
MTC	Market Transition Charge
MW	Megawatts
NAAQS	National Ambient Air Quality Standards
NERC	North American Electric Reliability Council
NJBPU	New Jersey Board of Public Utilities
NOAC	Northwest Ohio Aggregation Coalition
NOV	Notices of Violation
NO_x	Nitrogen Oxide
NRC	Nuclear Regulatory Commission
NUG	Non-Utility Generation
OCC	Ohio Consumers' Counsel
OCI	Other Comprehensive Income
OPEB	Other Post-Employment Benefits
PCAOB	Public Company Accounting Oversight Board (United States)
PJM	PJM Interconnection L.L.C.
PLR	Provider of Last Resort
PPUC	Pennsylvania Public Utility Commission
PRP	Potentially Responsible Party
PUCO	Public Utilities Commission of Ohio
PUHCA	Public Utility Holding Company Act
RTC	Regulatory Transition Charge
S&P	Standard & Poor's Ratings Service
SBC	Societal Benefits Charge
SEC	United States Securities and Exchange Commission
SFAS	Statement of Financial Accounting Standards
SFAS 71	SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation"
SFAS 87	SFAS No. 87, "Employers' Accounting for Pensions"
SFAS 101	SFAS No. 101, "Accounting for Discontinuation of Application of SFAS 71"
SFAS 106	SFAS No. 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions"
SFAS 115	SFAS No. 115, "Accounting for Certain Investments in Debt and Equity Securities"
SFAS 123	SFAS No. 123, "Accounting for Stock-Based Compensation"
SFAS 123(R)	SFAS No. 123(R), "Share-Based Payment"
SFAS 131	SFAS No. 131, "Disclosures about Segments of an Enterprise and Related Information"
SFAS 133	SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities"
SFAS 140	SFAS No. 140, "Accounting for Transfers and Servicing of Financial Assets and Extinguishment of Liabilities"
SFAS 142	SFAS No. 142, "Goodwill and Other Intangible Assets"
SFAS 143	SFAS No. 143, "Accounting for Asset Retirement Obligations"
SFAS 144	SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets"
SFAS 150	SFAS No. 150, "Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity"
SFAS 151	SFAS No. 151, "Inventory costs - an amendment of ARB No. 43, Chapter 4"
SO_2	Sulfur Dioxide
TBC	Transition Bond Charge
TMI-1	Three Mile Island Unit 1
TMI-2	Three Mile Island Unit 2
VIE	Variable Interest Entity

Management's Responsibility for Financial Statements

The consolidated financial statements were prepared by management who takes responsibility for their integrity and objectivity. The statements were prepared in conformity with accounting principles generally accepted in the United States and are consistent with other financial information appearing elsewhere in this report. PricewaterhouseCoopers LLP, an independent registered public accounting firm, has expressed an unqualified opinion on the Company's 2004 consolidated financial statements.

FirstEnergy Corp.'s internal auditors, who are responsible to the Audit Committee of FirstEnergy's Board of Directors, review the results and performance of operating units within the Company for adequacy, effectiveness and reliability of accounting and reporting systems, as well as managerial and operating controls.

FirstEnergy's Audit Committee consists of five independent directors whose duties include: consideration of the adequacy of the internal controls of the Company and the objectivity of financial reporting; inquiry into the number, extent, adequacy and validity of regular and special audits conducted by independent auditors and the internal auditors; and reporting to the Board of Directors the Committee's findings and any recommendation for changes in scope, methods or procedures of the auditing functions. The Committee is directly responsible for appointing the Company's independent registered public accounting firm and is charged with reviewing and approving all services performed for the Company by the independent registered public accounting firm and for reviewing and approving the related fees. The Committee reviews the independent registered public accounting firm's report on internal quality control and reviews all relationships between the independent registered public accounting firm and the Company, in order to assess the independent registered public accounting firm's independence. The Committee also reviews management's programs to monitor compliance with the Company's policies on business ethics and risk management. The Committee establishes procedures to receive and respond to complaints received by the Company regarding accounting, internal accounting controls, or auditing matters and allows for the confidential, anonymous submission of concerns by employees. The Audit Committee held six meetings in 2004.

Management's Report on Internal Control Over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rule 13a-15(f) of the Securities Exchange Act of 1934. Using the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in *Internal Control – Integrated Framework*, management conducted an evaluation of the effectiveness of the Company's internal control over financial reporting under the supervision of the chief executive officer and the chief financial officer. Based on that evaluation, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2004. Management's assessment of the effectiveness of the Company's internal control over financial reporting, as of December 31, 2004, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears on page 11.

Report of Independent Registered Public Accounting Firm

To the Stockholders and Board of Directors of FirstEnergy Corp.:

We have completed an integrated audit of FirstEnergy Corp.'s 2004 consolidated financial statements and of its internal control over financial reporting as of December 31, 2004 and audits of its 2003 and 2002 consolidated financial statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Our opinions, based on our audits, are presented below.

Consolidated financial statements

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, capitalization, common stockholders' equity, preferred stock, cash flows and taxes present fairly, in all material respects, the financial position of FirstEnergy Corp. and its subsidiaries at December 31, 2004 and 2003, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2004 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit of financial statements includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 2(K) to the consolidated financial statements, the Company changed its method of accounting for asset retirement obligations as of January 1, 2003. As discussed in Note 7 to the consolidated financial statements, the Company changed its method of accounting for the consolidation of variable interest entities as of December 31, 2003.

Internal control over financial reporting

Also, in our opinion, management's assessment, included in the accompanying Management's Report on Internal Control Over Financial Reporting, that the Company maintained effective internal control over financial reporting as of December 31, 2004 based on criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), is fairly stated, in all material respects, based on those criteria. Furthermore, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2004, based on criteria established in *Internal Control – Integrated Framework* issued by the COSO. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express opinions on management's assessment and on the effectiveness of the Company's internal control over financial reporting based on our audit. We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we consider necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

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

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

PricewaterhouseCoopers LLP
PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP
Cleveland, Ohio,
March 7, 2005

SELECTED FINANCIAL DATA

(In thousands, except per share amounts)

For the Years Ended December 31,	2004	2003	2002	2001	2000
Revenues	**$12,453,046**	$11,674,888	$11,453,354	$ 7,237,011	$ 6,470,488
Income Before Discontinued Operations and Cumulative Effect of Accounting Changes	**$ 873,779**	$ 424,249	$ 618,385	$ 654,946	$ 598,970
Net Income	**$ 878,175**	$ 422,764	$ 552,804	$ 646,447	$ 598,970
Basic Earnings per Share of Common Stock:					
Before Discontinued Operations and Cumulative Effect of Accounting Changes	**$ 2.67**	$ 1.40	$ 2.11	$ 2.85	$ 2.69
After Discontinued Operations and Cumulative Effect of Accounting Changes	**$ 2.68**	$ 1.39	$ 1.89	$ 2.82	$ 2.69
Diluted Earnings per Share of Common Stock:					
Before Discontinued Operations and Cumulative Effect of Accounting Changes	**$ 2.66**	$ 1.40	$ 2.10	$ 2.84	$ 2.69
After Discontinued Operations and Cumulative Effect of Accounting Changes	**$ 2.67**	$ 1.39	$ 1.88	$ 2.81	$ 2.69
Dividends Declared per Share of Common Stock*	**$ 1.9125**	$ 1.50	$ 1.50	$ 1.50	$ 1.50
Total Assets	**$31,067,944**	$32,909,948	$34,386,353	$37,351,513	$17,941,294
Capitalization as of December 31:					
Common Stockholders' Equity	**$ 8,589,294**	$ 8,289,341	$ 7,050,661	$ 7,398,599	$ 4,653,126
Preferred Stock:					
Not Subject to Mandatory Redemption	**335,123**	335,123	335,123	480,194	648,395
Subject to Mandatory Redemption	—	—	428,388	594,856	161,105
Long-Term Debt and Other Long-Term Obligations	**10,013,349**	9,789,066	10,872,216	12,865,352	5,742,048
Total Capitalization	**$18,937,766**	$18,413,530	$18,686,388	$21,339,001	$11,204,674

** Dividends declared in each year include four quarterly dividends of $0.375 per share paid in those years. In addition, a quarterly dividend of $0.4125 was declared in 2004 payable March 1, 2005, increasing the indicated annual dividend rate from $1.50 to $1.65 per share.*

PRICE RANGE OF COMMON STOCK

The Common Stock of FirstEnergy Corp. is listed on the New York Stock Exchange under the symbol "FE" and is traded on other registered exchanges.

	2004		2003	
First Quarter High-Low	**$39.37**	**$35.24**	$35.19	$27.04
Second Quarter High-Low	**$39.73**	**$36.73**	$38.90	$30.57
Third Quarter High-Low	**$42.23**	**$37.04**	$38.75	$25.82
Fourth Quarter High-Low	**$43.41**	**$38.35**	$35.95	$31.66
Yearly High-Low	**$43.41**	**$35.24**	$38.90	$25.82

Prices are based on reports published in The Wall Street Journal for New York Stock Exchange Composite Transactions.

HOLDERS OF COMMON STOCK

There were 143,111 and 142,825 holders of 329,836,276 shares of FirstEnergy's Common Stock as of December 31, 2004 and January 31, 2005, respectively. Information regarding retained earnings available for payment of cash dividends is given in Note 10(A) to the consolidated financial statements.

Management's Discussion and Analysis of Results of Operations and Financial Condition

This discussion includes forward-looking statements based on information currently available to management. Such statements are subject to certain risks and uncertainties. These statements typically contain, but are not limited to, the terms "anticipate," "potential," "expect," "believe," "estimate" and similar words and include reference to an indicated annual dividend. Actual results may differ materially due to the speed and nature of increased competition and deregulation in the electric utility industry, economic or weather conditions affecting future sales and margins, changes in markets for energy services, changing energy and commodity market prices, replacement power costs being higher than anticipated or inadequately hedged, maintenance costs being higher than anticipated, legislative and regulatory changes (including revised environmental requirements), adverse regulatory or legal decisions and outcomes (including revocation of necessary licenses or operating permits, fines or other enforcement actions and remedies) of government investigations, including by the Securities and Exchange Commission, the United States Attorney's Office and the Nuclear Regulatory Commission as disclosed in our Securities and Exchange Commission filings, generally, and with respect to the Davis-Besse Nuclear Power Station outage in particular, the availability and cost of capital, the continuing availability and operation of generating units, our inability to accomplish or realize anticipated benefits from strategic goals, our ability to improve electric commodity margins and to experience growth in the distribution business, our ability to access the public securities and other capital markets, further investigation into the causes of the August 14, 2003 regional power outage and the outcome, cost and other effects of present and potential legal and administrative proceedings and claims related to the outage, the final outcome in the proceeding related to FirstEnergy's Application for a Rate Stabilization Plan in Ohio, the risks and other factors discussed from time to time in our Securities and Exchange Commission filings, and other similar factors. Dividends declared from time to time during any annual period may in aggregate vary from the indicated amounts due to circumstances considered by the Board at the time of the actual declarations. FirstEnergy expressly disclaims any current intention to update any forward-looking statements contained herein as a result of new information, future events, or otherwise.

EXECUTIVE SUMMARY

On a non-GAAP basis, earnings in 2004 increased to $991 million, or basic earnings of $3.03 per share of common stock, from earnings of $736 million (basic earnings of $2.42 per share) in 2003 and $889 million (basic earnings of $3.03 per share) in 2002. On a GAAP basis, net income increased to $878 million, or basic earnings of $2.68 per share in 2004 from $423 million (basic earnings of $1.39 per share) in 2003 and $553 million (basic earnings of $1.89 per share) in 2002. The following Non-GAAP Reconciliation displays the unusual items resulting in the difference between GAAP and non-GAAP earnings.

Non-GAAP Reconciliation

	2004		2003		2002	
	After-tax Amount (Millions)	**Basic Earnings Per Share**	**After-tax Amount (Millions)**	**Basic Earnings Per Share**	**After-tax Amount (Millions)**	**Basic Earnings Per Share**
Earnings Before Unusual Items (Non-GAAP)	$991	$3.03	$736	$2.42	$889	$3.03
Cumulative effect of accounting change			102	0.33		
Discontinued international operations			(101)	(0.33)	(80)	(0.27)
Non-core asset sales/impairments	(60)	(0.19)	(125)	(0.41)	(62)	(0.21)
Davis-Besse impacts	(38)	(0.12)	(170)	(0.56)	(139)	(0.47)
JCP&L disallowance			(109)	(0.36)		
Litigation settlement	(11)	(0.03)				
Lake plants transaction					(17)	(0.06)
NRG settlement			99	0.33		
Long-term derivative contract adjustment					(11)	(0.04)
Generation project cancellation					(10)	(0.04)
Other	(4)	(0.01)	(9)	(0.03)	(17)	(0.05)
Net Income (GAAP)	$878	$2.68	$423	$1.39	$553	$1.89

The Non-GAAP measure above, earnings before unusual items, is not calculated in accordance with GAAP because it excludes the impact of "unusual items." Unusual items reflect the impact on earnings of events that are not routine, are related to discontinued businesses or are the cumulative effect of an accounting change. We believe presenting normalized earnings calculated in this manner provides useful information to investors in evaluating the ongoing results of our businesses and assists investors in comparing our operating performance to the operating performance of others in the energy sector.

Under our debt paydown and refinancing program, we retired, refinanced, or restructured more than $2.8 billion in long-term debt during the year. These financing activities contributed to the $143 million decrease in interest charges in 2004.

Sales for 2004 were up over the previous year, driven primarily by strong sales in the wholesale power market. This increase is largely reflective of a stronger economy and the return of the Davis-Besse Nuclear Power Station to active status. Despite milder weather experienced over much of our service area in 2004, our generating fleet produced a record 76 billion KWH. Our fossil fleet produced 46 billion KWH and our nuclear fleet produced a record 30 billion KWH.

The Company made a voluntary $500 million contribution to its pension plan in order to help add security to future plan benefits. The net after-tax cost of the contribution was approximately $300 million. This contribution is expected to reduce our overall risk profile, because it reduces uncertainty regarding the plan's unfunded liability.

We continue to participate in meaningful settlement negotiations with the parties to the New Source Review case involving our W. H. Sammis Plant (see Environmental Matters). As a result, the U.S. District Court judge hearing the case has delayed without rescheduling the remedy phase of the trial, originally scheduled to begin in January 2005.

In November 2004, the Board of Directors increased our indicated annual dividend to $1.65 per share, payable quarterly at a rate of $0.4125 per share. This action represents a 10% increase over the previous quarterly rate and is the first dividend increase since FirstEnergy was formed in 1997. The Board also adopted a dividend policy that will target sustainable annual dividend increases after 2005 that generally reflect an annual growth rate within the range of 4% to 5%, and an earnings payout ratio generally within the range of 50% to 60%.

At the end of December 2004, accrued dividends of approximately $135 million were included in other current liabilities on the accompanying consolidated balance sheet. Dividends declared in 2004 were $1.9125 which included quarterly dividends of $0.375 per share paid in each quarter of 2004 and a dividend of $0.4125 payable in the first quarter of 2005. The amount and timing of all dividend declarations are subject to the discretion of the Board and its consideration of business conditions, results of operations, financial condition and other factors.

FIRSTENERGY'S BUSINESS

FirstEnergy is a registered public utility holding company headquartered in Akron, Ohio that provides regulated and competitive energy services (see Results of Operations – Business Segments). Our eight EUOC provide transmission and distribution services and comprise the nation's fifth largest investor-owned electric system – based on serving 4.4 million customers within 36,100 square miles of Ohio, Pennsylvania and New Jersey. ATSI provides transmission services to our Ohio Companies and Penn. The service areas of our EUOC are highlighted below.

Operating Company	Area Served	Customers Served
OE	Central and northeastern Ohio	1,031,066
Penn	Western Pennsylvania	157,411
CEI	Northeastern Ohio	757,889
TE	Northwestern Ohio	311,225
JCP&L	Northern, western and east central New Jersey	1,061,764
Met-Ed	Eastern Pennsylvania	526,380
Penelec	Western Pennsylvania	588,066
ATSI	Service areas of OE, Penn, CEI and TE	

Competitive energy services are principally provided by FES. FSG and MYR provide heating, ventilation, air-conditioning, refrigeration, process piping, plumbing, electrical and facility control systems and high-efficiency electrotechnologies. While competitive revenues have increased since 2001, regulated energy services continue to provide the majority of our revenues and earnings.

Beginning in 2001, Ohio utilities that offered both competitive and regulated retail electric services were required to implement a corporate separation plan approved by the PUCO – one which provided a clear separation between regulated and competitive operations. FES provides generation services while the EUOC provide regulated transmission and distribution services. FGCO, a wholly owned subsidiary of FES, leases and operates fossil and hydroelectric plants owned by the Ohio Companies and Penn. Under the terms of the Ohio Rate Stabilization Plan, the deadline for achieving structural separation by transferring the ownership of applicable EUOC generating assets to a competitive affiliate was extended until twelve months after the termination of the Rate Stabilization Plan, unless otherwise extended further by the PUCO, or until December 31, 2008, whichever is earlier. All of the power supply requirements for the Ohio Companies and Penn are provided through FES.

FirstEnergy acquired international assets in the merger with GPU in November 2001. GPU Capital and its subsidiaries had provided electric distribution services in foreign countries (see Results of Operations – Discontinued Operations). GPU Power and its subsidiaries owned and operated generation facilities in foreign countries. As of January 30, 2004, all of the international operations had been divested because those assets were inconsistent with our vision for FirstEnergy.

STRATEGY

We continue to pursue our goal of being the leading regional supplier of energy and related services in the northeast quadrant of the United States, where we see the best opportunities for growth. Our fundamental business strategy remains stable and unchanged. While we continue to build a strong regional presence, key elements for our strategy are in place and management's focus continues to be on execution. We intend to continue providing competitively priced, high-quality products and value-added services – energy sales and services, energy delivery, power supply and supplemental services related to our core business.

Our current focus includes: (1) minimizing unplanned extended generation outages; (2) enhancing our system reliability; (3) optimizing our generation portfolio; (4) effectively managing commodity supplies and risks; (5) preserving and enhancing appropriate margins; (6) enhancing our credit profile and financial flexibility; and (7) managing the skills and diversity of our workforce.

RISKS

We face a number of industry and enterprise risks and challenges, including:

- Changes in commodity prices, which could adversely affect our margins;
- Complex and changing government regulations, which could have a negative impact on results of operations;
- Costs of compliance with environmental laws, which are significant, and the cost of compliance with future environmental laws, which could adversely affect cash flow and profitability;

- Financial performance risks related to the economic cycles of the electric utility industry;
- The continuing availability and operation of generating units, which is dependent on retaining the necessary licenses, permits, and operating authority from governmental entities, including the NRC;
- Risks of nuclear generation, including uncertainties relating to health and safety, additional capital costs, the adequacy of insurance coverage and nuclear plant decommissioning;
- Operational risks arising from the reliability of our power plants and transmission and distribution equipment;
- Regulatory changes in the electric industry, which could affect our competitive position and result in unrecoverable costs adversely affecting our business and results of operations;
- Human resource risks associated with the availability of trained and qualified labor to meet our future staffing requirements;
- Weather conditions such as tornadoes, hurricanes, storms and droughts, as well as seasonal temperature variations;
- A downgrade in credit ratings, which could negatively affect our ability to access capital; and
- We may ultimately incur liability in connection with federal proceedings described in Note 13 to the consolidated financial statements.

RECLASSIFICATIONS

As discussed in Notes 1 and 14 to the consolidated financial statements, certain prior year amounts have been reclassified to conform to the current year presentation. Revenues related to transmission activities previously recorded as wholesale electric sales revenues were reclassified as transmission revenues. Expenses (including transmission and congestion charges) were reclassified among purchased power, other operating costs and amortization of regulatory assets to conform to the current year presentation of generation commodity costs. As further discussed in Note 14 to the consolidated financial statements, segment reporting in 2003 and 2002 was reclassified to conform to the 2004 business segment organizations and operations. These reclassifications did not change previously reported earnings in 2003 and 2002.

RESULTS OF OPERATIONS

The 2004 increase in net income of $455 million from the prior year resulted from several factors. First, the number of unusual charges incurred in 2004 decreased as certain initiatives began to reach their conclusion in 2003 and early 2004. Second, adverse operating results at FSG led to impairment of its goodwill in 2003. Its remaining goodwill and certain other assets were further impaired in 2004 as we prepared to sell the FSG operations. Finally, a positive turn in the economy, moderation in the rate at which alternative suppliers expanded their presence in our franchise areas, and reduced expenses enhanced 2004 financial results. Moderating those positive results was the absence in 2004 of the NRG settlement gain recorded in 2003 and the cumulative effect of an accounting change which offset some of the negative 2003 factors described above.

The $130 million decrease in net income in 2003 compared with 2002 reflected many of the factors described above. Additional costs were being incurred during the extended outage at Davis-Besse for replacement power, accelerated maintenance, extended-scope enhancements to plant design and human performance and safety issues. Also, losses were being recorded on international operations, alternative suppliers were expanding more rapidly in our franchise areas, the economy negatively influenced financial results and we recorded our first impairment of goodwill. In 2003, the NRG settlement gain and cumulative effect of an accounting change offset the negative factors.

The financial results in 2004, 2003 and 2002 are summarized in the table below.

FirstEnergy	**2004**	**2003**	**2002**
	(In millions, except per share amounts)		
Total revenues	$12,453	$11,675	$11,453
Income before discontinued operations and cumulative effect of accounting change	874	424	618
Discontinued operations	4	(103)	(65)
Cumulative effect of accounting change	—	102	—
Net Income	$ 878	$ 423	$ 553
Basic Earnings Per Share:			
Income before discontinued operations and cumulative effect of accounting change	$2.67	$1.40	$2.11
Discontinued operations	0.01	(0.34)	(0.22)
Cumulative effect of accounting change	—	0.33	—
Net Income	$2.68	$1.39	$1.89
Diluted Earnings Per Share:			
Income before discontinued operations and cumulative effect of accounting change	$2.66	$1.40	$2.10
Discontinued operations	0.01	(0.34)	(0.22)
Cumulative effect of accounting change	—	0.33	—
Net Income	$2.67	$1.39	$1.88

Results of Operations - 2004 Compared With 2003

Sources of changes in total revenues are summarized in the following table:

Sources of Revenue Changes	**2004**	**2003**	**Increase (Decrease)**
		(In millions)	
Retail Electric Sales:			
EUOC – Wires	$ 4,701	$ 4,787	$ (86)
– Generation	3,158	3,139	19
FES	637	566	71
Wholesale Electric Sales:			
EUOC	512	570	(58)
FES	1,823	1,143	680
Total Electric Sales	10,831	10,205	626
Transmission Revenues:			
EUOC	333	23	310
FES	39	59	(20)
Other Revenues:			
EUOC	361	443	(82)
FES - Generation	35	10	25
FSG	398	327	71
International	—	25	(25)
Miscellaneous	456	583	(127)
Total Revenues	$12,453	$11,675	$778

Changes in electric generation sales and distribution deliveries in 2004 are summarized in the following table:

Changes in KWH Sales	Increase (Decrease)
Electric Generation Sales:	
Retail:	
EUOC	(1.5)%
FES	4.9%
Wholesale	26.7%
Total Electric Generation Sales	7.7%
EUOC Distribution Deliveries:	
Residential	2.0%
Commercial	2.6%
Industrial	0.6%
Total Distribution Deliveries	1.6%

Retail sales by our EUOC remain the largest source of revenues, contributing more than 70% of electric revenues and over 60% of total revenues. The following major factors contributed to the $67 million decrease in retail electric revenues from our EUOC in 2004.

Sources of the Changes in EUOC Retail Electric Revenue	Increase (Decrease)
	(In millions)
Changes in Customer Consumption:	
Alternative suppliers	$(77)
Economy, weather and other	109
	32
Changes in Price:	
Rate changes	(19)
Shopping incentives	(51)
Rate mix and other	(29)
	(99)
Net Decrease	$(67)

Lower prices were partially offset by increased energy use due to a strengthening economy. Although the demand for energy increased in all three customer groups – residential, commercial and industrial – milder weather in 2004 moderated the energy needs of residential and commercial customers. Customers shopping in our franchise areas for alternative energy suppliers remained a major factor contributing to lower EUOC revenues with alternative suppliers providing a larger portion of franchise customer energy requirements.

Alternative suppliers provided 24.3% of the total energy delivered to retail customers in our franchise areas in 2004, compared to 21.8% in 2003. Lower prices resulted from three factors – a shopping credit rate increase, a change in the mix of sales with fewer retail customers receiving EUOC generation in Ohio, and lower base distribution rates at JCP&L. Partially offsetting JCP&L's lower base distribution rates were higher energy, MTC and SBC rates.

Additional credits provided to customers (primarily under the Ohio transition plan) to promote customer shopping for alternative suppliers reduced regulated retail electric sales revenues. Reductions from shopping incentives are deferred for future recovery under our Ohio transition plan and do not affect current period earnings.

Electric sales by FES increased by $751 million primarily from additional sales to the wholesale market that increased $680 million in 2004. Higher electric sales to the wholesale market were possible due in part to a 13% increase in generation resulting from record production from our generating fleet. Retail sales increased $71 million, with nearly half of the revenue increase from customers within our franchise areas switching to FES.

The gross generation margin in 2004 improved by $402 million compared to 2003, with electric generation revenue increasing more rapidly than the costs of fuel and purchased power. Excluding the unusual charge resulting from the July 2003 JCP&L rate decision, the gross generation margin improved by $249 million and the ratio of gross generation margin to revenue increased from 26.1% to 27.1%, primarily reflecting additional lower-cost nuclear generation, offset in part by higher purchased power prices.

Gross Generation Margin	2004	2003	Increase
		(In millions)	
Electric generation revenue	$6,130	$5,418	$712
Fuel and purchased power costs	4,469	4,159	310
Gross Generation Margin	$1,661	$1,259	$402

Income before discontinued operations and the cumulative effect of an accounting change increased $450 million in 2004. In addition to the impact of improved gross generation margin discussed above, the following factors contributed to the change in earnings:

- Lower nuclear expenses of $169 million primarily as a result of one scheduled refueling outage at Beaver Valley Unit 1 in 2004 compared to three scheduled refueling outages in 2003 (Beaver Valley Unit 1, Beaver Valley Unit 2 and Perry) and reduced incremental maintenance costs at the Davis-Besse Nuclear Power Station related to its restart;
- Lower energy delivery expenses of $94 million due to reduced storm restoration costs in 2004, a higher level of construction activities in 2004 compared to a higher level of maintenance activities in the prior year and additional distribution reliability expenses incurred in the third quarter of 2003;
- Reduced fossil generation expenses of $49 million due to less maintenance in 2004 compared to the prior year;
- A net $51 million decrease in employee benefits expense primarily as a result of reduced postretirement benefit plan expenses (see Postretirement Plans below), offset in part by higher incentive compensation and severance costs;
- Lower interest charges of $143 million primarily due to debt and preferred stock redemption and refinancing activities and pollution control note repricings;
- A net $81 million reduction in goodwill impairment charges for FSG with $36 million (see Note 2(H)) and $117 million recognized in 2004 and 2003, respectively; and
- Additional deferrals of regulatory assets of $63 million, due principally to Ohio shopping incentives.

Partially offsetting the above sources of improved earnings were five factors:

- Reduced revenues of $86 million from distribution deliveries due to lower prices;
- Increased amortization of regulatory assets of $87

million primarily from additional Ohio transition plan amortization and a change in amortization resulting from the July 2003 JCP&L rate decision;

- The absence in 2004 of the 2003 earnings benefit of $168 million realized from the settlement of our claim against NRG for the terminated sale of four fossil plants;
- An aggregate increase in Ohio property tax expense and other state taxes of $40 million; and
- Increased income taxes of $263 million primarily reflecting higher taxable earnings.

Results of Operations - 2003 Compared With 2002

Sources of changes in total revenues are summarized in the following table:

Sources of Revenue Changes	2003	2002	Increase (Decrease)
		(In millions)	
Retail Electric Sales:			
EUOC – Wires	$4,787	$4,872	$(85)
– Generation	3,139	3,357	(218)
FES	566	348	218
Wholesale Electric Sales:			
EUOC	570	511	59
FES	1,143	568	575
Total Electric Sales	10,205	9,656	549
Transmission Revenues:			
EUOC	23	39	(16)
FES	59	2	57
Other Revenues:			
EUOC	443	387	56
FES - Generation	10	39	(29)
FSG	327	383	(56)
International	25	294	(269)
Miscellaneous	583	653	(70)
Total Revenues	$11,675	$11,453	$ 222

Changes in electric generation sales and distribution deliveries in 2003 are summarized in the following table:

Changes in KWH Sales	Increase (Decrease)
Electric Generation Sales:	
Retail:	
EUOC	(7.2)%
FES	53.0%
Wholesale	40.2%
Total Electric Generation Sales	8.3%
EUOC Distribution Deliveries:	
Residential	(0.7)%
Commercial	1.2%
Industrial	(0.4)%
Total Distribution Deliveries	—%

Retail sales by our EUOC contributed more than 70% of electric revenues and over 60% of total revenues. The following major factors contributed to the $303 million decrease in retail electric revenues from our EUOC in 2003:

Sources of the Changes in EUOC Retail Electric Revenue	Increase (Decrease)
	(In millions)
Changes in Customer Consumption:	
Alternative suppliers	$(295)
Economy, weather and other	(16)
	(311)
Changes in Price:	
Rate changes	(11)
Shopping incentives	(6)
Rate mix and other	25
	8
Net Decrease	$(303)

The lower retail electric revenues resulted principally from increased sales by alternative suppliers in our franchise areas. Alternative suppliers provided 21.8% of the total energy delivered to retail customers in our franchise areas in 2003, compared to 15.7% in 2002. As a result, generation kilowatt-hour sales to retail customers of our regulated services were 7.2% lower. Additional credits provided to customers (primarily under the Ohio transition plan) to promote customer shopping for alternative suppliers further reduced regulated retail electric sales revenues. Reductions from shopping incentives are deferred for future recovery under our Ohio transition plan and do not materially affect current period earnings. The NJBPU decision in July 2003 that lowered JCP&L's base electric rates effective August 1, 2003 contributed to lower rates.

Electric sales by FES increased by $793 million primarily from additional sales to the wholesale market that increased $575 million in 2003 on a 75% increase in kilowatt-hour sales. A majority of the increase was due to sales by our competitive electric energy services segment for a portion of New Jersey's BGS requirements and sales in the spot market. Retail sales by FES increased by $218 million as a result of a 53% increase in kilowatt-hour sales. That increase primarily resulted from retail customers within our Ohio franchise areas switching to FES under Ohio's electricity choice program and from growth in competitive retail sales outside our franchise areas.

The gross generation margin in 2003 declined by $215 million compared to the same period in 2002. Excluding the unusual charge of $153 million of power costs that were disallowed in the July 2003 JCP&L rate decision referred to above, our gross generation margin decreased $62 million and the ratio of gross generation margin to revenue decreased from 30.8% to 26.1%. Higher electric generation sales resulted principally from the additional sales in the wholesale market and were more than offset by increased fuel and purchased power costs. Purchased power costs increased by $879 million due to higher unit costs and additional quantities purchased. Increased volumes were required to supply obligations assumed by FES for BGS sales in New Jersey, as well as other wholesale commitments, and additional supplies were required to replace reduced nuclear generation (down 14%). Reduced nuclear generation output resulted from additional refueling outage work performed at the Perry and Beaver Valley plants in 2003 and the Davis-Besse extended outage.

Gross Generation Margin	2003	2002	Increase (Decrease)
		(In millions)	
Electric generation revenue	$5,418	$4,784	$ 634
Fuel and purchased power costs	4,159	3,310	849
Gross Generation Margin	$1,259	$1,474	$(215)

Income before discontinued operations and the cumulative effect of an accounting change decreased $194 million in 2003. In addition to the impact of reduced gross generation margin and lower revenues from distribution deliveries discussed above, the following factors contributed to the decrease in earnings:

- Asset impairment charges of $56 million incurred in 2003 including a $26 million non-cash charge related to the divestiture of our interest in TEBSA; a $13 million impairment on the monetization of the note received from the sale of our 79.9% interest in Avon; an additional $5 million impairment upon the divestiture of our remaining interest in Avon; and $12 million related to the disposition of NEO and the write down of our investment in Pantellos, an internet business-to-business marketplace serving the utility sector;
- A non-cash goodwill impairment charge of $117 million recorded in the third quarter of 2003 reducing the carrying value of FSG;
- Increased energy delivery costs of $36 million principally due to storm restoration expenses and an accelerated reliability program within JCP&L's service territory;
- Higher nuclear expenses of $54 million as a result of an additional scheduled nuclear refueling outage in 2003 and unplanned work performed during the scheduled refueling outages at the Perry Plant and Beaver Valley Unit 1. The higher production costs were partially offset by lower maintenance costs at the Davis-Besse Nuclear Power Station;
- Planned maintenance outages at three of our fossil generating plants during the fourth quarter of 2003 increased non-nuclear operating expenses by approximately $25 million;
- Increased postretirement plan expenses (see Postretirement Plans below) offset in part by lower incentive compensation costs contributed to a net cost increase of $94 million;
- Revenues less operating expenses for energy-related services declined $17 million due to general declines associated with economic conditions;
- An estimated environmental liability of $15 million was recognized in the fourth quarter of 2003; and
- Increased amortization of regulatory assets of $138 million due principally to additional Ohio transition plan amortization and a July 2003 JCP&L rate case disallowance.

Partially offsetting these higher costs were five factors:

- A settlement of our claim against NRG for the terminated sale of four fossil plants resulted in a $168 million gain;
- Reduced depreciation resulting from several factors — lower charges resulting from the implementation of SFAS 143 ($61 million), revised service life assumptions for nuclear generating plants ($28 million) and reduced depreciation rates resulting from the JCP&L rate case ($18 million);
- Lower interest charges of $146 million primarily due to debt and preferred stock redemption and refinancing activities and pollution control note repricings;
- The absence of unusual charges recognized in 2002 resulted in a further net reduction of other operating expenses ($181 million) in 2003; and
- Reduced income taxes of $106 million primarily reflecting lower taxable earnings.

Cumulative Effect of Accounting Change

Results in 2003 included an after-tax credit to net income of $102 million recorded upon the adoption of SFAS 143 in January 2003 (see discussion below). We identified applicable legal obligations as defined under the new standard for nuclear power plant decommissioning, reclamation of a sludge disposal pond at the Bruce Mansfield Plant and two coal ash disposal sites. As a result of adopting SFAS 143 in January 2003, asset retirement costs of $602 million were recorded as part of the carrying amount of the related long-lived asset, offset by accumulated depreciation of $415 million. The ARO liability at the date of adoption was $1.11 billion, including accumulated accretion for the period from the date the liability was incurred to the date of adoption. As of December 31, 2002, we had recorded decommissioning liabilities of $1.24 billion. We expect substantially all of our nuclear decommissioning costs for Met-Ed, Penelec, JCP&L and Penn to be recoverable in rates over time. Therefore, we recognized a regulatory liability of $185 million upon adoption of SFAS 143 for the transition amounts related to establishing the ARO for nuclear decommissioning for those companies. The remaining cumulative effect adjustment for unrecognized depreciation and accretion, offset by the reduction in the existing decommissioning liabilities and the reversal of accumulated estimated removal costs for non-regulated generation assets, was a $175 million increase to income, or $102 million net of income taxes. The application of SFAS 143 (excluding the cumulative adjustment described above) resulted in the following changes to expense categories and net income in 2003:

Effect of SFAS 143	Increase (Decrease)
	(In millions)
Other operating expense:	
Cost of removal expenditures (previously included in depreciation)	$10
Depreciation:	
Elimination of decommissioning expense	(89)
Depreciation of asset retirement cost	2
Accretion of asset retirement liability	42
Elimination of removal cost component	(16)
Net decrease to depreciation	(61)
Income taxes	21
Net income effect	$30

DISCONTINUED OPERATIONS

Discontinued operations for 2004, 2003 and 2002 include FES' natural gas business (see Note 2(J)) which management expects to sell within one year. In 2003 and 2002, discontinued operations were reflected for Emdersa and EGSA, as we substantially completed our exit from foreign operations acquired through the merger with GPU in 2001. In addition, the results for the FSG subsidiaries, Colonial Mechanical, Webb Technologies and Ancoma, Inc. and the MARBEL subsidiary, NEO, which were divested in 2003, have been reported as discontinued operations for the years 2003 and 2002. The following table summarizes the sources of income (losses) from discontinued operations:

Discontinued Operations (Net of tax)	2004	2003	2002
		(In millions)	
Emdersa – abandonment	$—	$ (67)	$—
EGSA – loss on sale	—	(33)	—
Ancoma – loss on sale	—	(3)	—
Total losses	—	(103)	—
Reclassification of operating income (loss) to discontinued operations:			
FES' natural gas business	4	(2)	15
Emdersa, EGSA, Colonial, Webb, Ancoma and NEO	—	2	(80)
Total	$ 4	$(103)	$(65)

POSTRETIREMENT PLANS

Strengthened equity markets (reducing pension costs), as well as amendments to our health care benefits plan in the first quarter of 2004 and the Medicare Act signed by President Bush in December 2003 (reducing OPEB costs) combined to reduce postretirement benefits expenses by $109 million in 2004 from the prior year. A $191 million increase in benefits expenses in 2003 from 2002 resulted from declines in equity markets in 2001 and 2002 and a reduction in our assumed discount rate in 2002 which increased pension expenses. Also, higher health care payments and a related increase in projected trend rates led to higher OPEB expenses in 2003. The following table reflects the portion of postretirement costs that were charged to expense in 2004, 2003 and 2002.

Postretirement Expenses (Income)	2004	2003	2002
		(In millions)	
Pension	$ 83	$ 123	$(14)
OPEB	87	156	102
Total	$170	$ 279	$ 88

Pension and OPEB expenses are included in various cost categories and have contributed to cost decreases in 2004, discussed above. The $500 million voluntary contribution made in 2004 is expected to result in a reduction in pension costs in 2005, 2006 and 2007 compared to the level they would have been without the voluntary contribution. Including the effect of higher interest costs resulting from funding the voluntary contribution, earnings per share are expected to benefit by approximately $0.06 in each of the next three years. See "Critical Accounting Policies - Pension and Other Postretirement Benefits Accounting" for a discussion of the impact of underlying assumptions on postretirement expenses.

SUPPLY PLAN

Our affiliates are obligated to provide generation service with an estimated power supply of 99.5 billion KWH for 2005. These obligations arise from customers who have elected to continue to receive generation service from our EUOCs under regulated retail rate tariffs and from customers who have selected FES as their alternate generation provider. Geographically, approximately 63% of the total generation service obligation is for customers located in the MISO market area and 37% for customers located in the PJM market area. Included in the PJM market area are obligations of FES to provide power to electric distribution companies in the state of New Jersey, including JCP&L. FES incurred this obligation as a successful bidder in the State of New Jersey's auction of BGS.

Within the franchise territories of the EUOC, alternative energy suppliers currently provide generation service for approximately 1,800 MW (summer peak) of load with an estimated energy requirement of eight billion KWH. If these alternate suppliers fail to deliver power to.their customers located in the EUOC's service areas, the EUOC must procure replacement power in the role of PLR (see Note 2(D) for discussion of the auction of JCP&L's PLR obligation). JCP&L's costs for any replacement power would be recovered under the applicable state regulatory rules.

To meet these generation service obligations, our affiliates own and operate 13,387 MW of installed generating capacity, which for 2005 is expected to provide approximately 75% of the required power supply. The balance has been secured through a mix of long-term purchases (term of contract greater than one year) and short-term purchases (term of contract less than one year). Changes in power supply requirements will be met through spot market transactions.

PJM INTERCONNECTION TRANSACTIONS

FES engages in purchase and sale transactions in the PJM Market (see Note 2 (D)) to support the supply of end-use customers, including its BGS obligation in New Jersey and PLR requirements in Pennsylvania. FES meets its supply commitments by transmitting energy into the PJM control area and through bilateral purchased power contracts with counterparties in PJM. FES schedules purchase and sale transactions for each hour in PJM on a day-ahead basis with system balancing occurring real-time. FES sells energy to the PJM Market at the location of its supply (transmitted and contracted energy) and purchases energy from the PJM Market at the location of its demand (end-use customer load).

FES accounts for energy transactions in the PJM Market in accordance with EITF 99-19, recognizing purchases and sales on a gross basis by recording each discrete transaction (see Note 2(D)). This presentation may not be comparable to other energy companies that have dedicated generating capacity in ISOs or fail to meet the criteria for gross presentation in EITF 99-19.

RESULTS OF OPERATIONS – BUSINESS SEGMENTS

We have three reportable segments: regulated services, competitive electric energy services and facilities (HVAC) services. The aggregate "Other" segments do not individually meet the criteria to be considered a reportable segment. "Other" consists of international businesses that have subsequently been divested, MYR (a construction service company); natural gas operations and telecommunications services. The assets and revenues for the other business operations are below the quantifiable threshold for operating segments for separate disclosure as "reportable segments." FirstEnergy's primary segment is its regulated services segment, whose operations include the regulated sale of electricity and distribution and transmission services by its eight EUOC in Ohio, Pennsylvania and New Jersey. The competitive electric energy services business segment primarily consists of the subsidiaries (FES, FGCO and FENOC) that sell electricity in deregulated markets and operate the generation facilities of OE, CEI, TE and Penn resulting from the deregulation of the Companies' electric generation business (see Note 2(A) – Accounting for the Effects of Regulation).

The regulated services segment designs, constructs, operates and maintains our regulated transmission and distribution systems. Its revenues are primarily derived from electricity delivery and transition costs recovery. The regulated services segment assets include generating units that are leased to the competitive electric energy services. Its internal revenues represent the rental revenues for the generating unit leases.

The competitive electric energy services segment has responsibility for our generation operations as discussed under Note 2(A) to the consolidated financial statements. Its net income is primarily derived from revenues from all electric generation sales consisting of generation services to regulated franchise customers who have not chosen an alternative generation supplier, retail sales in deregulated markets and all domestic unregulated electricity sales in the retail and wholesale markets and the related costs of electricity generation and sourcing of commodity requirements. Its net income also reflects the expense of the intersegment generating unit leases discussed above and property tax amounts related to those generating units.

Segment reporting for 2003 and 2002 was reclassified to conform with the current year business segment organization and operations emphasizing our regulated electric businesses and competitive electric energy operations. A previous reportable segment was the more expansive competitive services segment whose aggregate operations consisted of our generation operations, natural gas commodity sales, providing local and long-distance phone service and other competitive energy related businesses such as facilities services and construction service (MYR) which was viewed as offering a comprehensive menu of energy related services. Management's focus is now on our core electric business. This has resulted in a change in performance review analysis from an aggregate view of all competitive services operations to a focus on its competitive electric energy operations. During our periodic review of reportable segments under SFAS 131, that change resulted in the revision of reportable segments to the separate reporting of competitive electric energy operations, facilities services and including all other competitive services operations in the "Other" segment. Facilities services is being disclosed as a reporting segment due to the subsidiaries qualifying as held for sale (see Note 2 (J)). In addition, certain amounts (including transmission and congestion charges) were reclassified among purchased power, other operating costs and depreciation and amortization to conform with the current year presentation of generation commodity costs. Interest expense on holding company debt and corporate support services revenues and expenses are now included in "Reconciling Items" and "Other" includes those operating segment results discussed above.

Financial results discussed below include revenues and expenses from transactions among our business segments. A reconciliation of segment financial results to consolidated financial results is provided in Note 14 to the consolidated financial statements. Net income (loss) by business segment was as follows:

Net Income (Loss) By Business Segment	2004	2003	2002
		(In millions)	
Segments:			
Regulated services	$1,015	$1,164	$962
Competitive electric energy services	104	(320)	(170)
Facilities services	(36)	(81)	3
Other	45	(160)	(47)
Reconciling Items*	(250)	(180)	(195)
Total	$ 878	$ 423	$553

** Includes interest expense on holding company debt, corporate support services revenues and expenses and other reconciling items.*

Regulated Services - 2004 versus 2003

Financial results of the regulated services segment were as follows:

Regulated Services	2004	2003	Increase (Decrease)
		(In millions)	
Total revenues	$5,713	$5,572	$141
Income before cumulative effect of accounting change	1,015	1,063	(48)
Net income	1,015	1,164	(149)

The change in operating revenues resulted from the following sources:

Sources of Revenue Changes	2004	2003	Increase (Decrease)
		(In millions)	
Electric sales	$4,701	$4,787	$ (86)
Other revenues:			
External sales	694	466	228
Internal sales	318	319	(1)
Total Revenues	$5,713	$5,572	$141

The net increase in operating revenues resulted from:

- A decrease of $86 million in retail sales – a $60 million reduction in revenues from distribution deliveries and a $26 million increase in the credits for shopping incentives to customers; and
- A $228 million increase in other revenues primarily

due to higher transmission revenues and, to a lesser extent, earnings recognized on decommissioning trust investments (see Note 5 - Investments).

Income before discontinued operations and the cumulative effect of an accounting change decreased $48 million. In addition to the above changes in revenue, the following factors contributed to the change:

- The absence in 2004 of the earnings benefit of the 2003 settlement of our claim against NRG for the terminated sale of four fossil plants, which resulted in a $168 million gain;
- An aggregate increase in Ohio property tax expense and other state taxes of $32 million; and
- Additional MISO and PJM transmission costs of $238 million related to the transmission component of other revenue discussed above.

Partially offsetting those factors were:

- Lower energy delivery expenses (net of refunds to third-party suppliers) of $71 million due to reduced storm restoration costs in 2004, a higher level of construction activities in 2004 compared to a higher level of maintenance activities in the prior year and distribution reliability expenses incurred in the third quarter of 2003;
- Lower interest charges of $130 million primarily related to debt and preferred stock redemption and refinancing activities and pollution control note repricings; and
- Reduced income taxes of $38 million primarily reflecting reduced taxable earnings.

Regulated Services - 2003 versus 2002

Financial results for regulated services were as follows:

Regulated Services	2003	2002	Increase (Decrease)
		(In millions)	
Total revenues	$5,572	$5,616	$ (44)
Income before cumulative effect of accounting change	1,063	962	101
Net income	1,164	962	202

The change in operating revenues resulted from the following sources:

Sources of Revenue Changes	2003	2002	Increase (Decrease)
		(In millions)	
Electric sales	$4,787	$4,872	$(85)
Other revenues:			
External sales	466	426	40
Internal sales	319	318	1
Total Revenues	$5,572	$5,616	$(44)

The net decrease in operating revenues resulted from:

- A decrease of $85 million in retail sales - a $40 million reduction in revenues from distribution deliveries and a $45 million increase in the credits for shopping incentives to customers; and
- A net $40 million increase in other revenues due in part to JCP&L TBC revenue and jobbing and contracting revenue.

Income before discontinued operations and the cumulative effect of an accounting change increased $101 million. The following factors offset the lower revenues and contributed to the net increase in income:

- Settlement of our claim against NRG for the terminated sale of four fossil plants which resulted in our recording a $168 million pre-tax credit to earnings;
- Lower interest charges of $95 million primarily related to debt and preferred stock redemption and refinancing activities and pollution control note repricings; and
- The absence of unusual charges recognized in 2002 of $6 million.

Partially offsetting the above sources of improved earnings were four factors:

- Increased energy delivery costs of $41 million principally due to storm restoration expenses and an accelerated reliability program within JCP&L's service territory;
- A net increase in depreciation and amortization expense of $9 million resulting from additional amortization of regulatory assets offset in part by reduced depreciation;
- Additional MISO and PJM transmission costs of $29 million related to the transmission component of other revenue; and
- Increased income taxes of $57 million primarily reflecting higher taxable earnings.

Competitive Electric Energy Services - 2004 versus 2003

Financial results for competitive electric energy services were as follows:

Competitive Electric Energy Services	2004	2003	Increase
		(In millions)	
Total revenues	$6,204	$5,487	$717
Net income (loss)	104	(320)	424

The change in total revenues resulted from the following sources:

Sources of Revenue Changes	2004	2003	Increase
		(In millions)	
Electric sales	$6,130	$5,418	$712
Other revenues	74	69	5
Total Revenues	$6,204	$5,487	$717

The net increase in electric sales resulted from:

- Higher retail generation sales from customer choice programs ($71 million) and EUOC regulated customers ($19 million); and
- Increased FES wholesale revenues of $680 million offset in part by a $58 million decrease in sales to EUOC wholesale customers.

The gross generation margin increased $402 million as electric generation revenues increased at a greater rate than the related costs of fuel and purchased power. Higher electric generation revenues resulted from increased sales to both retail and wholesale customers. Excluding the impact of the July 2003 JCP&L rate decision, the gross generation margin increased $249 million, reflecting the benefit of increased sales and the availability of additional lower-cost nuclear generation.

Net income increased $424 million. In addition to the improved gross generation margin discussed above, the following factors contributed to the increase in earnings:

- Lower nuclear expenses of $169 million primarily as a result of one scheduled refueling outage at Beaver Valley Unit 1 in 2004 compared to three scheduled refueling outages in 2003 (Beaver Valley Unit 1, Beaver Valley Unit 2 and Perry) and reduced incremental maintenance costs at the Davis-Besse Nuclear Power Station related to its restart; and
- Reduced fossil generation expenses of $49 million due to less maintenance in 2004 compared to the prior year.

Partially offsetting the above sources of improved earnings were increased income taxes of $294 million reflecting higher taxable earnings.

Competitive Electric Energy Services - 2003 versus 2002

Financial results for competitive electric energy services were as follows:

Competitive Electric Energy Services	2003	2002	Increase
		(In millions)	
Total revenues	$5,487	$4,825	$ 662
Net loss	320	170	150

The change in total revenues resulted from the following sources:

Sources of Revenue Changes	2003	2002	Increase
		(In millions)	
Electric sales	$5,418	$4,784	$634
Other revenues	69	41	28
	$5,487	$4,825	$662

The net increase in electric sales resulted from increased FES wholesale revenues of $575 million and increased sales to EUOC wholesale customers of $59 million.

The gross generation margin decreased $215 million as fuel and purchased power costs increased more rapidly than related electric generation revenue. Excluding the unusual charge from the July 2003 JCP&L rate decision, the gross generation margin decreased $62 million, reflecting higher fuel and purchased power costs. Purchased power costs increased due to higher unit costs and additional quantities purchased. Increased volumes were required to supply obligations assumed and to replace reduced nuclear generation.

In addition to the reduced gross generation margin discussed above, the following factors contributed to the increase in the net loss:

- Higher nuclear expenses of $54 million as a result of an additional scheduled nuclear refueling outage in 2003 and unplanned work performed during the scheduled refueling outages at the Perry Plant and Beaver Valley Unit 1. The higher production costs were partially offset by lower maintenance costs at the Davis-Besse Nuclear Power Station; and
- Planned maintenance outages at three of our fossil generating plants during the fourth quarter of 2003 increased non-nuclear operating expenses by approximately $25 million.

Partially offsetting the above sources of lower earnings were reduced income taxes of $134 million reflecting lower taxable income.

Facilities Services - 2004 versus 2003

Financial results for facilities services were as follows:

Facilities Services	2004	2003	Increase (Decrease)
		(In millions)	
Total revenues	$398	$327	$71
Net loss	36	81	(45)

Revenue increased $71 million or 22% in 2004 compared to 2003 reflecting stronger market conditions. Losses from FSG goodwill impairment dominated financial results in 2004 and 2003 resulting in non-cash, pre-tax charges to earnings of $36 million and $117 million, respectively (see Note 2 (H)). The impairment in 2003 was identified during our annual assessment of goodwill and in 2004 from an analysis performed at year-end when a firm decision was made to divest all FSG assets. Excluding the after-tax impact of the goodwill impairments FSG experienced net income in 2004 of $1 million, following a $255,000 loss in 2003.

Facilities Services - 2003 versus 2002

Financial results for facilities services were as follows:

Facilities Services	2003	2002	(Decrease)
		(In millions)	
Total revenues	$327	$383	$(56)
Net income (loss)	(81)	3	(84)

Revenues decreased $56 million or 15% in 2003 primarily reflecting depressed market conditions and reduced customer maintenance services due to mild weather. The loss in 2003 resulted principally from the effect of the $117 million pre-tax charge (discussed above). Excluding the effect of the goodwill impairment, after-tax earnings decreased $3 million in 2003 compared to 2002.

CAPITAL RESOURCES AND LIQUIDITY

Our cash requirements in 2004 for operating expenses, construction expenditures, scheduled debt maturities and preferred stock redemptions were met without increasing our net debt and preferred stock outstanding. During 2005, we expect to meet our contractual obligations primarily with cash from operations. Thereafter, we expect to use a combination of cash from operations and funds from the capital markets.

Changes in Cash Position

The primary source of ongoing cash for FirstEnergy, as a holding company, is cash dividends from its subsidiaries. The holding company also has access to $1.375 billion through revolving credit facilities. In 2004, FirstEnergy received $782 million of cash dividends on common stock from its subsidiaries and paid $491 million in cash dividends on common stock to its shareholders. There are no material restrictions on the payments of cash dividends by our subsidiaries.

As of December 31, 2004, we had $53 million of cash and cash equivalents, compared with $114 million as of December 31, 2003. Cash and cash equivalents as of December 31, 2003 included $32 million received in December 2003 from the NRG settlement claim sold in January 2004. The major sources for changes in these balances are summarized below.

Cash Flows From Operating Activities

Our consolidated net cash from operating activities is provided primarily by our regulated and competitive electric energy businesses (see Results of Operations – Business Segments above). Net cash provided from operating activities was $1.877 billion in 2004, $1.755 billion in 2003 and $1.932 billion in 2002, summarized as follows:

Operating Cash Flows	2004	2003	2002
Increase (Decrease)		*(In millions)*	
Cash earnings[1]	$2,168	$1,825	$1,640
Pension trust contribution[2]	(300)	—	—
Working capital and other	9	(70)	292
Total	$1,877	$1,755	$1,932

[1] Cash earnings are a non-GAAP measure (see reconciliation below).

[2] Pension trust contribution net of $200 million of income tax benefits.

Cash earnings (in the table above) is not a measure of performance calculated in accordance with GAAP. We believe that cash earnings is a useful financial measure because it provides investors and management with an additional means of evaluating our cash-based operating performance. The following table reconciles cash earnings with net income.

Reconciliation of Cash Earnings	2004	2003	2002
		(In millions)	
Net Income (GAAP)	$ 878	$ 423	$ 553
Non-Cash Charges (Credits):			
Provision for depreciation	590	607	722
Amortization of regulatory assets	1,166	1,079	941
Deferral of new regulatory assets	(257)	(194)	(184)
Nuclear fuel and lease amortization	96	66	81
Deferred costs recoverable as regulatory assets	(417)	(427)	(544)
Deferred income taxes*	58	54	77
Goodwill impairment	36	117	—
Disallowed regulatory assets	—	153	—
Cumulative effect of accounting change	—	(175)	—
Other non-cash expenses	18	122	(6)
Cash Earnings (Non-GAAP)	$2,168	$1,825	$1,640

** Excludes $200 million of deferred tax benefit from pension contribution in 2004.*

Net cash provided from operating activities increased $122 million in 2004 compared to 2003 due to a $343 million increase in cash earnings as described under "Results of Operations" and a $79 million increase from changes in working capital, partially offset by a $300 million after-tax voluntary pension trust contribution. The working capital increase resulted in part from changes of $88 million in receivables, $78 million in prepayments and other current assets, $59 million in payables and a $53 million NUG power contract restructuring transaction, partially offset by a $237 million decrease in accrued tax balances. Net cash provided from operating activities decreased $177 million in 2003 compared to 2002 due to a $362 million decrease in working capital partially offset by a $185 million increase in cash earnings, as described above under "Results of Operations." The working capital decrease primarily resulted from changes of $388 million in payables and $165 million in prepayments and other current assets, partially offset by a $196 million increase in accrued tax balances.

Cash Flows From Financing Activities

In 2004, 2003 and 2002, net cash used for financing activities of $1.457 billion, $1.298 billion and $1.138 billion, respectively, primarily reflected the redemptions of debt and preferred stock shown below. The following table provides details regarding new issues and redemptions during 2004, 2003 and 2002:

Securities Issued or Redeemed	2004	2003	2002
		(In millions)	
New Issues:			
Common stock	$ —	$ 934	$ —
Pollution control notes	261	—	158
Senior secured notes	300	400	370
Unsecured notes	400	627	140
	$ 961	$1,961	$ 668
Redemptions:			
First mortgage bonds	$ 589	$1,483	$ 728
Pollution control notes	80	238	93
Senior secured notes	471	323	278
Long-term revolving credit	95	85	—
Unsecured notes	337	—	210
Preferred stock	2	127	522
	$1,574	$2,256	$1,831
Short-term borrowings, net	$ (351)	$ (575)	$ 479

Net cash used for financing activities increased by $159 million in 2004 from 2003. The increase resulted primarily from the absence of a $934 million common equity financing in 2003 and a $37 million increase in common stock dividends partially offset by an $840 million decrease in net redemption of preferred securities and debt. Net cash used for financing activities in 2003 increased $160 million from 2002. The increase in cash used for financing activities resulted primarily from an increase in net redemptions of debt and preferred securities of $1.1 billion partially offset by the common equity financing in 2003.

We had approximately $170 million of short-term indebtedness at the end of 2004 compared to approximately $522 million at the end of 2003. Available borrowing capability as of December 31, 2004 included the following:

Borrowing Capability	FirstEnergy	OE	Total
		(In millions)	
Long-term revolving credit	$1,375	$375	$1,750
Utilized	(215)	—	(215)
Letters of credit	(135)	—	(135)
Net	1,025	375	1,400
Short-term bank facilities	—	34	34
Utilized	—	(21)	(21)
Net	—	13	13
Total Unused Borrowing Capability	$ 1,025	$388	$1,413

At the end of 2004, the Ohio Companies and Penn had the aggregate capability to issue approximately $4.4 billion of additional FMB on the basis of property additions and retired bonds under the terms of their respective mortgage indentures. The issuance of FMB by OE and CEI are also subject to provisions of their senior note indentures generally limiting the incurrence of additional secured debt, subject to certain exceptions that would permit, among other things, the issuance of secured debt (including FMB) (i) supporting pollution control notes or similar obligations, or (ii) as an extension, renewal or replacement of previously outstanding secured debt. In addition, these provisions would permit OE and CEI to incur additional secured debt not otherwise permitted by a specified exception of up to $641 million and $588 million, respectively, as of December 31, 2004. Under the provisions of its senior note indenture, JCP&L may issue additional FMB only as collateral for senior notes. As of December 31, 2004, JCP&L had the capability to issue $644 million of additional senior notes upon the basis of FMB collateral. Based upon applicable earnings coverage tests in their respective charters, OE, Penn, TE and JCP&L could issue a total of $4.5 billion of preferred stock (assuming no additional debt was issued) as of the end of 2004. CEI, Met-Ed and Penelec have no restrictions on the issuance of preferred stock (see Note 10(C) – Long-Term Debt and Other Long-Term Obligations for a discussion of debt covenants).

As of December 31, 2004, approximately $1.0 billion remained under FirstEnergy's shelf registration statement, filed with the SEC in 2003, to support future securities issues. The shelf registration provides the flexibility to issue and sell various types of securities, including common stock, debt securities, and share purchase contracts and related share purchase units.

At the end of 2004 and 2003, our common equity as a percentage of capitalization stood at 45% compared to 38% at the end of 2002. The higher common equity percentage in 2004 and 2003 compared to 2002 reflects net redemptions of preferred stock and long-term debt, and the increase in retained earnings.

Our working capital and short-term borrowing needs are met principally with a syndicated $1 billion three-year revolving credit facility maturing in June 2007. Combined with our syndicated $375 million three-year facility maturing in October 2006, a $125 million three-year facility for OE maturing in October 2006, and a syndicated $250 million two-year facility for OE maturing in May 2005, our primary syndicated credit facilities total $1.75 billion. These revolving credit facilities, combined with an aggregate $550 million of accounts receivable financing facilities for OE, CEI, TE, Met-Ed, Penelec and Penn, are intended to provide liquidity to meet our short-term working capital requirements and those of our subsidiaries. Total unused borrowing capability under existing facilities and accounts receivable financing facilities totaled $1.7 billion as of December 31, 2004.

Borrowings under these facilities are conditioned on maintaining compliance with certain financial covenants in the agreements. FirstEnergy and OE are each required to maintain a debt to total capitalization ratio of no more than 0.65 to 1 and a contractually defined fixed charge coverage ratio of no less than 2 to 1. As of December 31, 2004, FirstEnergy's and OE's fixed charge coverage ratios, as defined under the credit agreements, were 4.48 to 1 and 7.15 to 1, respectively. FirstEnergy's and OE's debt to total capitalization ratios, as defined under the credit agreements, were 0.55 to 1 and 0.39 to 1, respectively. FirstEnergy and OE are in compliance with these financial covenants. The ability to draw on each of these facilities is also conditioned upon FirstEnergy or OE making certain representations and warranties to the lending banks prior to drawing on their respective facilities, including a representation that there has been no material adverse change in their business, condition (financial or otherwise), results of operations, or prospects.

Neither FirstEnergy's nor OE's primary credit facilities contain any provisions that either restrict their ability to borrow or accelerate repayment of outstanding advances as a result of any change in their credit ratings. Each primary facility does contain "pricing grids", whereby the cost of funds borrowed under the facility is related to the credit ratings of the company borrowing the funds.

Our regulated companies have the ability to borrow from each other and the holding company to meet their short-term working capital requirements. A similar but separate arrangement exists among our unregulated companies. FESC administers these two money pools and tracks surplus funds of FirstEnergy and the respective regulated and unregulated subsidiaries, as well as proceeds available from bank borrowings. For the regulated companies, available bank borrowings include $1.75 billion from FirstEnergy's and OE's revolving credit facilities. For the unregulated companies, available bank borrowings include only FirstEnergy's $1.375 billion of revolving credit facilities. Companies receiving a loan under the money pool agreements must repay the principal amount of the loan, together with accrued interest, within 364 days of borrowing the funds. The rate of interest is the same for each company receiving a loan from their respective pool and is based on the average cost of funds available through the pool. The average interest rate for borrowings in 2004 was 1.43% for the regulated companies' money pool and 1.55% for the unregulated companies' money pool.

Our access to capital markets and costs of financing are influenced by the ratings of our securities. The following table shows our securities ratings as of December 31, 2004. The ratings outlook from the ratings agencies on all securities is stable.

Ratings of Securities	Securities	S&P	Moody's	Fitch
FirstEnergy	Senior unsecured	BB+	Baa3	BBB-
OE	Senior secured	BBB	Baa1	BBB+
	Senior unsecured	BB+	Baa2	BBB
	Preferred stock	BB	Ba1	BBB-
CEI	Senior secured	BBB-	Baa2	BBB-
	Senior unsecured	BB+	Baa3	BB
	Preferred stock	BB	Ba2	BB-
TE	Senior secured	BBB-	Baa2	BBB-
	Senior unsecured	BB+	Baa3	BB
	Preferred stock	BB	Ba2	BB-
Penn	Senior secured	BBB	Baa1	BBB+
	Senior unsecured[1]	BB+	Baa2	BBB
	Preferred stock	BB	Ba1	BBB-
JCP&L	Senior secured	BBB+	Baa1	BBB+
	Preferred stock	BB	Ba1	BBB
Met-Ed	Senior secured	BBB	Baa1	BBB+
	Senior unsecured	BBB-	Baa2	BBB
Penelec	Senior secured	BBB	Baa1	BBB+
	Senior unsecured	BBB-	Baa2	BBB

(1) Penn's only senior unsecured debt obligations are notes underlying pollution control revenue refunding bonds issued by the Ohio Air Quality Development Authority to which bonds this rating applies.

On December 10, 2004, S&P reaffirmed our 'BBB-' corporate credit rating and kept the outlook stable. S&P noted that the stable outlook reflects our improving financial profile and cash flow certainty through 2006. S&P stated that should the two refueling outages at the Davis-Besse and Perry nuclear plants scheduled for the first quarter of 2005 be completed successfully without any significant negative findings and delays, our outlook would be revised to positive. S&P also stated that a ratings upgrade in the next several months did not seem likely, as remaining issues of concern to S&P, primarily the outcome of environmental litigation and SEC investigations, are not likely to be resolved in the short term.

Cash Flows From Investing Activities

Net cash flows used in investing activities resulted principally from property additions. Regulated services expenditures for property additions primarily include expenditures supporting the distribution of electricity. Capital expenditures by the competitive electric energy services segment are principally generation-related. The following table summarizes 2004 investments by our regulated services and competitive services segments:

Summary of Cash Flows Used for Investing Activities	Property Additions	Investments	Other	Total
		(In millions)		
2004 Sources (Uses)				
Regulated services	$(572)	$181	$ (88)	$(479)
Competitive electric energy services	(246)	16	(2)	(232)
Facilities services	(3)	—	2	(1)
Other	(4)	184	(6)	174
Reconciling items	(21)	(22)	100	57
Total	$(846)	$359	$ 6	$(481)
2003 Sources (Uses)				
Regulated services	$(434)	$105	$ 16	$(313)
Competitive electric energy services	(335)	(32)	8	(359)
Facilities services	(4)	61	(70)	(13)
Other	(9)	46	116	153
Reconciling items	(74)	28	9	(37)
Total	$(856)	$208	$ 79	$(569)
2002 Sources (Uses)				
Regulated services	$(490)	$ 27	$ 2	$(461)
Competitive electric energy services	(391)	—	(25)	(416)
Facilities services	(6)	—	—	(6)
Other	(9)	96	43	130
Reconciling items	(102)	(40)	62	(80)
Total	$(998)	$ 83	$ 82	$(833)

Net cash used for investing activities in 2004 decreased by $88 million from 2003. The decrease was primarily due to $278 million in cash proceeds from certificates of deposit received in the third quarter of 2004 partially offset by a $117 million change in NUG trust activity. Net cash used for investing activities in 2003 decreased by $264 million from 2002. The decrease was primarily due to a $142 million decrease in property additions and a $174 million increase in cash payments on long-term notes receivable.

Our capital spending for the period 2005-2007 is expected to be about $3.3 billion (excluding nuclear fuel), of which $979 million applies to 2005. Investments for additional nuclear fuel during the 2005-2007 period are estimated to be approximately $268 million, of which about $53 million applies to 2005. During the same period, our nuclear fuel investments are expected to be reduced by approximately $280 million and $90 million, respectively, as the nuclear fuel is consumed.

CONTRACTUAL OBLIGATIONS

Contractual Obligations

As of December 31, 2004, our estimated cash payments under existing contractual obligations that we consider firm obligations are as follows:

Contractual Obligations	Total	2005	2006-2007	2008-2009	Thereafter
			(In millions)		
Long-term debt [5]	$10,890	$ 710	$1,565	$ 622	$ 7,993
Short-term borrowings	170	170	—	—	—
Preferred stock [1]	17	2	14	1	—
Capital leases [2]	19	5	6	2	6
Operating leases [2]	2,362	183	349	376	1,454
Pension funding [3]	—	—	—	—	—
Fuel and purchased power [4]	13,765	2,464	4,184	3,148	3,969
Total	$27,223	$3,534	$6,118	$4,149	$13,422

(1) Subject to mandatory redemption.

(2) See Note 6 to the consolidated financial statements.

(3) We estimate that no further pension contributions will be required through 2009 to maintain our defined benefit pension plan's funding at a minimum required level as determined by government regulations. We are unable to estimate projected contributions beyond 2009. See Note 3 to the consolidated financial statements.

(4) Amounts under contract with fixed or minimum quantities and approximate timing.

(5) Amounts reflected do not include interest on long-term debt.

Guarantees and Other Assurances

As part of normal business activities, we enter into various agreements on behalf of our subsidiaries to provide financial or performance assurances to third parties. Such agreements include contract guarantees, surety bonds, and LOCs. Some of the guaranteed contracts contain ratings contingent collateralization provisions.

As of December 31, 2004, our maximum exposure to potential future payments under outstanding guarantees and other assurances totaled approximately $2.4 billion, as summarized below:

Guarantees and Other Assurances	Maximum Exposure
	(In millions)
FirstEnergy Guarantees of Subsidiaries	
Energy and Energy-Related Contracts [1]	$ 878
Other [2]	149
	1,027
Surety Bonds	279
LOC [3][4]	1,098
Total Guarantees and Other Assurances	$2,404

[1] Issued for a one-year term, with a 10-day termination right by FirstEnergy.

[2] Issued for various terms.

[3] Includes $135 million issued for various terms under LOC capacity available in FirstEnergy's revolving credit agreement and $299 million outstanding in support of pollution control revenue bonds issued with various maturities.

[4] Includes approximately $216 million pledged in connection with the sale and leaseback of Beaver Valley Unit 2 by CEI and TE, $294 million pledged in connection with the sale and leaseback of Beaver Valley Unit 2 by OE and $154 million pledged in connection with the sale and leaseback of Perry Unit 1 by OE.

We guarantee energy and energy-related payments of our subsidiaries involved in energy commodity activities – principally to facilitate normal physical transactions involving electricity, gas, emission allowances and coal. We also provide guarantees to various providers of subsidiary financing principally for the acquisition of property, plant and equipment. These agreements legally obligate us to fulfill the obligations of our subsidiaries directly involved in these energy and energy-related transactions or financings where the law might otherwise limit the counterparties' claims. If demands of a counterparty were to exceed the ability of a subsidiary to satisfy existing obligations, our guarantee enables the counterparty's legal claim to be satisfied by our other assets. The likelihood that such parental guarantees will increase amounts otherwise paid by us to meet our obligations incurred in connection with ongoing energy and energy-related contracts is remote.

While these types of guarantees are normally parental commitments for the future payment of subsidiary obligations, subsequent to the occurrence of a credit rating downgrade or "material adverse event" the immediate posting of cash collateral or provision of an LOC may be required of the subsidiary. The following table summarizes collateral provisions in effect as of December 31, 2004:

Collateral Provisions	Total Exposure	Collateral Paid Cash	Collateral Paid LOC	Remaining Exposure[1]
		(In millions)		
Credit rating downgrade	$349	$162	$ 18	$169
Adverse event	135	—	22	113
Total	$484	$162	$40	$282

[1] As of February 7, 2005, our total exposure decreased to $476 million and the remaining exposure increased to $290 million - net of $146 million of cash collateral and $40 million of LOC collateral provided to counterparties.

Most of our surety bonds are backed by various indemnities common within the insurance industry. Surety bonds and related guarantees provide additional assurance to outside parties that contractual and statutory obligations will be met in a number of areas including construction contracts, environmental commitments and various retail transactions.

We have guaranteed the obligations of the operators of the TEBSA project up to a maximum of $6.0 million (subject to escalation) under the project's operations and maintenance agreement. In connection with the sale of TEBSA in January 2004, the purchaser indemnified FirstEnergy against any loss under this guarantee. We have also provided an LOC (currently at $47 million), which is renewable and declines yearly based upon the senior outstanding debt of TEBSA.

OFF-BALANCE SHEET ARRANGEMENTS

We have obligations that are not included on our Consolidated Balance Sheets related to the sale and leaseback arrangements involving Perry Unit 1, Beaver Valley Unit 2 and the Bruce Mansfield Plant, which are reflected as part of the operating lease payments disclosed above (see Notes 6 and 7). The present value of these sale and leaseback operating lease commitments, net of trust investments, total $1.4 billion as of December 31, 2004.

CEI and TE sell substantially all of their retail customer receivables to CFC, a wholly owned subsidiary of CEI. CFC subsequently transfers the receivables to a trust (a "qualified special purpose entity" under SFAS 140) under an asset-backed securitization agreement. This arrangement provided $84 million of off-balance sheet financing as of December 31, 2004. See Note 12 to the consolidated financial statements for additional information regarding this arrangement.

We have equity ownership interests in various businesses that are accounted for using the equity method. There are no undisclosed material contingencies related to these investments. Certain guarantees that we do not expect to have a material current or future effect on our financial condition, liquidity or results of operations are disclosed above as contractual obligations.

MARKET RISK INFORMATION

We use various market risk sensitive instruments, including derivative contracts, primarily to manage the risk of price and interest rate fluctuations. Our Risk Policy Committee, comprised of members of senior management, provides general management oversight to risk management activities throughout the company. They are responsible for promoting the effective design and implementation of sound risk management programs. They also oversee compliance with corporate risk management policies and established risk management practices.

Commodity Price Risk

We are exposed to market risk primarily due to fluctuations in electricity, natural gas, coal, nuclear fuel and emission allowance prices. To manage the volatility relating to these exposures, we use a variety of non-derivative and derivative instruments, including forward contracts, options, futures contracts and swaps. The derivatives are used principally for hedging purposes and, to a much lesser extent, for trading purposes. Most of our non-hedge derivative contracts represent non-trading positions that do not qualify for hedge treatment under SFAS 133. The change in the fair value of commodity derivative contracts related to energy production during 2004 is summarized in the following table:

Increase (Decrease) in the Fair Value of Derivative Contracts	Non-Hedge	Hedge	Total
		(In millions)	
Change in the fair value of commodity derivative contracts			
Outstanding net asset as of January 1, 2004	$ 67	$ 12	$ 79
New contract value when entered	—	—	—
Additions/change in value of existing contracts	(4)	6	2
Change in techniques/assumptions	—	—	—
Settled contracts	(1)	(16)	(17)
Outstanding net asset as of December 31, 2004 (1)	62	2	64
Non-commodity net assets as of December 31, 2004:			
Interest rate swaps (2)	—	4	4
Net Assets - Derivatives Contracts as of December 31, 2004	$ 62	$ 6	$ 68
Impact of Changes in Commodity Derivative Contracts (3)			
Income Statement Effects (Pre-Tax)	$ (5)	$—	$ (5)
Balance Sheet Effects:			
OCI (Pre-Tax)	$ —	$(10)	$(10)

(1) Includes $61 million in non-hedge commodity derivative contracts, which are offset by a regulatory liability.

(2) Interest rate swaps are primarily treated as fair value hedges. Changes in derivative values of the fair value hedges are offset by changes in the hedged debts' premium or discount (see Interest Rate Swap Agreements below).

(3) Represents the increase in value of existing contracts, settled contracts and changes in techniques/ assumptions.

Derivatives are included on the Consolidated Balance Sheet as of December 31, 2004 as follows:

	Non-Hedge	Hedge	Total
		(In millions)	
Current-			
Other assets	$ 2	$ 2	$ 4
Other liabilities	(2)	(1)	(3)
Non-Current-			
Other deferred charges	62	15	77
Other noncurrent liabilities	—	(10)	(10)
Net assets	$62	$ 6	$ 68

The valuation of derivative contracts is based on observable market information to the extent that such information is available. In cases where such information is not available, we rely on model-based information. The model provides estimates of future regional prices for electricity and an estimate of related price volatility. We use these results to develop estimates of fair value for financial reporting purposes and for internal management decision making. Sources of information for the valuation of commodity derivative contracts by year are summarized in the following table:

Source of Information– Fair Value by Contract Year

	2005	2006	2007	2008	Thereafter	Total
				(In millions)		
Prices actively quoted (1)	$ 2	$ 1	$—	$—	$ —	$ 3
Other external sources (2)	17	10	—	—	—	27
Prices based on models	—	—	10	9	15	34
Total (3)	$19	$11	$10	$ 9	$ 15	$64

(1) Exchange traded.

(2) Broker quote sheets.

(3) Includes $61 million from an embedded option that is offset by a regulatory liability and does not affect earnings.

We perform sensitivity analyses to estimate our exposure to the market risk of our commodity positions. A hypothetical 10% adverse shift in quoted market prices in the near term on both our trading and nontrading derivative instruments would not have had a material effect on our consolidated financial position or cash flows as of December 31, 2004. We estimate that if energy commodity prices experienced an adverse 10% change, net income for the next twelve months would decrease by approximately $3 million.

Interest Rate Risk

Our exposure to fluctuations in market interest rates is reduced since a significant portion of our debt has fixed interest rates, as noted in the table below.

Comparison of Carrying Value to Fair Value

Year of Maturity	2005	2006	2007	2008	2009	There-after	Total	Fair Value
				(In millions)				
Assets:								
Investments other than Cash and Cash Equivalents-Fixed Income	$73	$ 82	$ 77	$ 57	$68	$1,729	$2,086	$2,243
Average interest rate	6.8%	7.8%	7.9%	7.7%	7.8%	6.0%	6.3%	
Liabilities:								
Long-term Debt and Other Long-term Obligations:								
Fixed rate (1)	$495	$1,327	$238	$338	$284	$6,674	$9,356	$9,915
Average interest rate	7.4%	5.7%	6.6%	5.3%	6.8%	6.5%	6.4%	
Variable rate (1)	$215					$1,319	$1,534	$1,538
Average interest rate	3.6%					2.2%	2.4%	
Preferred Stock Subject to Mandatory Redemption	$2	$2	$12	$1			$17	$16
Average dividend rate	7.5%	7.5%	7.6%	7.4%			7.6%	
Short-term Borrowings	$170						$170	$170
Average interest rate	2.4%						2.4%	

(1) Balances and rates do not reflect the fixed-to-floating interest rate swap agreements discussed below.

We are subject to the inherent interest rate risks related to refinancing maturing debt by issuing new debt securities. As discussed in Note 6 to the consolidated financial statements, our investments in capital trusts effectively reduce future lease obligations, also reducing interest rate risk. While fluctuations in the fair value of our Ohio Companies' decommissioning trust balances will eventually affect earnings (affecting OCI initially) based on the guidance provided by SFAS 115, our non-Ohio EUOC have the opportunity to recover from customers, or refund to customers, the difference between the investments held in trust and their decommissioning obligations. Thus, there is not expected to be an earnings effect from fluctuations in their decommissioning trust balances. As of December 31, 2004, decommissioning trust balances totaled $1.583 billion, with $975 million held by our Ohio Companies and the balance held by our non-Ohio EUOC. As of year-end 2004, trust balances of our Ohio Companies were comprised of 64% equity securities and 36% debt instruments.

Interest Rate Swap Agreements

We have utilized fixed-to-floating interest rate swap agreements, as part of our ongoing effort to manage the interest rate risk of our debt portfolio. These derivatives are treated as fair value hedges of fixed-rate, long-term debt issues – protecting against the risk of changes in the fair value of fixed-rate debt instruments due to lower interest rates. Swap maturities, call options, fixed interest rates and interest payment dates match those of the underlying obligations. During the fourth quarter of 2004, in a period of declining interest rates, we unwound swaps with a total notional amount of $400 million. We received $12 million in cash gains from unwinding the swaps and interest expense will be reduced by that amount over the term of the related hedged debt. Due to the differences between fixed and variable debt rates, interest expense in 2004 and 2003 was reduced by $37 million and $27 million, respectively. We increased the total notional amount of outstanding interest rate swaps to $1.65 billion as of December 31, 2004, from $1.15 billion at the end of 2003 from cumulative swap activities. As of December 31, 2004, the debt underlying the interest rate swaps had a weighted average fixed interest rate of 5.53%, which the swaps have effectively converted to a current weighted average variable interest rate of 3.42%.

Fixed to Floating Rate Interest Rate Swaps (Fair value hedges)

December 31, 2004			December 31, 2003		
Notional Amount	Maturity Date	Fair Value	Notional Amount	Maturity Date	Fair Value
		(Dollars in millions)			
$200	2006	$(1)	$200	2006	$ 1
100	2008	(1)	50	2008	—
100	2010	1	100	2010	1
100	2011	2	100	2011	1
400	2013	4	350	2013	(1)
100	2014	2	—	—	—
150	2015	(7)	150	2015	(10)
200	2016	1	—	—	—
150	2018	5	150	2018	1
50	2019	2	50	2019	1
100	2031	(4)	—	—	—

Equity Price Risk

Included in nuclear decommissioning trusts are marketable equity securities carried at their current fair value of approximately $951 million and $779 million as of December 31, 2004 and 2003, respectively. A hypothetical 10% decrease in prices quoted by stock exchanges would result in a $95 million reduction in fair value as of December 31, 2004 (see Note 5 – Fair Value of Financial Instruments).

CREDIT RISK

Credit risk is the risk of an obligor's failure to meet the terms of any investment contract, loan agreement or otherwise perform as agreed. Credit risk arises from all activities in which success depends on issuer, borrower or counterparty performance, whether reflected on or off the balance sheet. We engage in transactions for the purchase and sale of commodities including gas, electricity, coal and emission allowances. These transactions are often with major energy companies within the industry.

We maintain credit policies with respect to our counterparties to manage overall credit risk. This includes performing independent risk evaluations, actively monitoring portfolio trends and using collateral and contract provisions to mitigate exposure. As part of our credit program, we aggressively manage the quality of our portfolio of energy contracts, evidenced by a current weighted average risk rating for energy contract counterparties of BBB (S&P). As of December 31, 2004, the largest credit concentration was with one party, currently rated investment grade that represented 7% of our total credit risk. Within our unregulated energy subsidiaries, 99% of credit exposures, net of collateral and reserve, were with investment-grade counterparties as of December 31, 2004.

REGULATORY MATTERS

In Ohio, New Jersey and Pennsylvania, laws applicable to electric industry restructuring contain similar provisions that are reflected in the Companies' respective state regulatory plans. These provisions include:

- restructuring the electric generation business and allowing the Companies' customers to select a competitive electric generation supplier other than the Companies;
- establishing or defining the PLR obligations to customers in the Companies' service areas;
- providing the Companies with the opportunity to recover potentially stranded investment (or transition costs) not otherwise recoverable in a competitive generation market;
- itemizing (unbundling) the price of electricity into its component elements – including generation, transmission, distribution and stranded costs recovery charges;
- continuing regulation of the Companies' transmission and distribution systems; and
- requiring corporate separation of regulated and unregulated business activities.

The EUOC recognize, as regulatory assets, costs which the FERC, PUCO, PPUC and NJBPU have authorized for recovery from customers in future periods or for which authorization is probable. Without the probability of such authorization, costs currently recorded as regulatory assets would have been charged to income as incurred. All regulatory assets are expected to be recovered from customers under the Companies' respective transition and regulatory plans. Based on those plans, the Companies continue to bill and collect cost-based rates for their transmission and distribution services, which remain regulated; accordingly, it is appropriate that the Companies continue the application of SFAS 71 to those operations. Regulatory assets that do not earn a current return totaled approximately $240 million as of December 31, 2004.

Regulatory Assets As of December 31	2004	2003	Increase (Decrease)
		(In millions)	
OE	$1,116	$1,451	$ (335)
CEI	959	1,056	(97)
TE	375	459	(84)
Penn*	—	28	(28)
JCP&L	2,176	2,558	(382)
Met-Ed	693	1,028	(335)
Penelec	200	497	(297)
ATSI	13	—	13
Total	$5,532	$7,077	$(1,545)

** Changes in Penn's net regulatory asset components in 2004 resulted in net regulatory liabilities of approximately $18 million included in Other Noncurrent Liabilities on the Consolidated Balance Sheet as of December 31, 2004.*

Regulatory assets by source are as follows:

Regulatory Assets By Source As of December 31	2004	2003	Increase (Decrease)
		(In millions)	
Regulatory transition costs	$4,889	$6,427	$(1,538)
Customer shopping incentives*	612	371	241
Customer receivables for future income taxes	246	340	(94)
Societal benefits charge	51	81	(30)
Loss on reacquired debt	89	75	14
Employee postretirement benefits costs	65	77	(12)
Nuclear decommissioning, decontamination and spent fuel disposal costs	(169)	(96)	(73)
Asset removal costs	(340)	(321)	(19)
Property losses and unrecovered plant costs	50	70	(20)
Other	39	53	(14)
Total	$5,532	$7,077	$(1,545)

** The Ohio Companies are deferring customer shopping incentives and interest costs as new regulatory assets in accordance with the transition and rate stabilization plans. These regulatory assets, totaling $612 million as of December 31, 2004, will be recovered through a surcharge rate equal to the RTC rate in effect when the transition costs have been fully recovered. Recovery of the new regulatory assets will begin at that time and amortization of the regulatory assets for each accounting period will be equal to the surcharge revenue recognized during that period.*

Ohio

On February 24, 2004, the Ohio Companies filed a revised Rate Stabilization Plan to address PUCO concerns related to the original Rate Stabilization Plan that the Ohio Companies filed in October 2003. On June 9, 2004, the PUCO issued an order approving the revised Rate Stabilization Plan, subject to conducting a competitive bid process. On August 5, 2004, the Ohio Companies accepted the Rate Stabilization Plan as modified and approved by the PUCO on August 4, 2004. In the second quarter of 2004, the Ohio Companies implemented the accounting modifications related to the extended amortization periods and interest cost deferrals on the deferred customer shopping incentive balances. On October 1 and October 4, 2004, the OCC and NOAC, respectively, filed appeals with the Supreme Court of Ohio to overturn the June 9, 2004 PUCO order and associated entries on rehearing.

The revised Rate Stabilization Plan extends current generation prices through 2008, ensuring adequate generation supply at stabilized prices, and continues the Ohio Companies' support of energy efficiency and economic development efforts. Other key components of the revised Rate Stabilization Plan include the following:

- extension of the amortization period for transition costs being recovered through the RTC for OE from 2006 to as late as 2007; for CEI from 2008 to as late as mid-2009 and for TE from mid-2007 to as late as mid-2008;
- deferral of interest costs on the accumulated customer shopping incentives as new regulatory assets; and
- ability to request increases in generation charges during 2006 through 2008, under certain limited conditions, for increases in fuel costs and taxes.

On December 9, 2004, the PUCO rejected the auction price results from a required competitive bid process and issued an entry stating that the pricing under the approved revised Rate Stabilization Plan will take effect on January 1, 2006. The PUCO may cause the Ohio Companies to undertake, no more often than annually, a similar competitive bid process to secure generation for the years 2007 and 2008. Any acceptance of future competitive bid results would terminate the Rate Stabilization Plan pricing, but not the related approved accounting, and not until twelve months after the PUCO authorizes such termination.

On December 30, 2004, the Ohio Companies filed an application with the PUCO seeking tariff adjustments to recover increases of approximately $30 million in transmission and ancillary service-related costs beginning January 1, 2006. The Ohio Companies also filed an application for authority to defer costs such as those associated with MISO Day 1, MISO Day 2, congestion fees, FERC assessment fees, and the ATSI rate increase (described below), as applicable, from October 1, 2003 through December 31, 2005.

See Note 9 to the consolidated financial statements for further details and a complete discussion of regulatory matters in Ohio.

New Jersey

In July 2003, the NJBPU announced its JCP&L base electric rate proceeding decision, which reduced JCP&L's annual revenues effective August 1, 2003 and disallowed $153 million of deferred energy costs. The NJBPU decision also provided for an interim return on equity of 9.5% on JCP&L's rate base. The decision ordered a Phase II proceeding be conducted to review whether JCP&L is in compliance with current service reliability and quality standards. The BPU also ordered that any expenditures and projects undertaken by JCP&L to increase its system's reliability be reviewed as part of the Phase II proceeding, to determine their prudence and reasonableness for rate recovery. In that Phase II proceeding, the NJBPU could increase JCP&L's return on equity to 9.75% or decrease it to 9.25%, depending on its assessment of the reliability of JCP&L's service. Any reduction would be retroactive to August 1, 2003. JCP&L recorded charges to net income for the year ended December 31, 2003, aggregating $185 million ($109 million net of tax) consisting of the $153 million of disallowed deferred energy costs and $32 million of other disallowed regulatory assets. In its final decision and order issued on May 17, 2004, the NJPBU clarified the method for calculating interest attributable to the cost disallowances, resulting in a $5.4 million reduction from the amount estimated in 2003. JCP&L filed an August 15, 2003 interim motion for rehearing and reconsideration with the NJBPU and a June 1, 2004 supplemental and amended motion for rehearing and reconsideration. On July 7, 2004, the NJBPU granted limited reconsideration and rehearing on the following issues: (1) deferred cost disallowances (2) the capital structure including the rate of return (3) merger savings, including amortization of costs to achieve merger savings; and (4) decommissioning. Management is unable to predict when a decision may be reached by the NJBPU.

On July 16, 2004, JCP&L filed the Phase II petition and testimony with the NJBPU requesting an increase in base rates of $36 million for the recovery of system reliability costs and a 9.75% return on equity. The filing also requests an increase to the MTC deferred balance recovery of approximately $20 million annually. The Ratepayer Advocate filed testimony on November 16, 2004, JCP&L submitted rebuttal testimony on January 4, 2005. Settlement conferences are ongoing.

See Note 9 to the consolidated financial statements for further details and a complete discussion of regulatory matters in New Jersey.

Pennsylvania

Met-Ed and Penelec purchase a portion of their PLR requirements from FES through a wholesale power sale agreement. The PLR sale is automatically extended for each successive calendar year unless any party elects to cancel the agreement by November 1 of the preceding year. Under the terms of the wholesale agreement, FES retains the supply obligation and the supply profit and loss risk, for the portion of power supply requirements not self-supplied by Met-Ed and Penelec under their NUG contracts and other power contracts with nonaffiliated third party suppliers. This arrangement reduces Met-Ed's and Penelec's exposure to high wholesale power prices by providing power at a fixed price for their uncommitted PLR energy costs during the term of the agreement with FES. Met-Ed and Penelec are authorized to continue deferring differences between NUG contract costs and current market prices.

On January 12, 2005, Met-Ed and Penelec filed, before the PPUC, a request for deferral of transmission-related costs beginning January 1, 2005 estimated to be approximately $8 million per month.

See Note 9 to the consolidated financial statements for further details and a complete discussion of regulatory matters in Pennsylvania.

Transmission

On September 16, 2004, the FERC issued an order that imposed additional obligations on CEI under certain pre-Open Access transmission contracts among CEI and the cities of Cleveland and Painesville. Under the FERC's decision, CEI may be responsible for a portion of new energy market charges imposed by MISO when its energy markets begin in the spring of 2005. CEI filed for rehearing of the order from the FERC on October 18, 2004. The impact of the FERC decision on CEI is dependent upon many factors, including the arrangements made by the cities for transmission service, the startup date for the MISO energy market, and the resolution of the rehearing request, and cannot be determined at this time.

On November 1, 2004, ATSI requested authority from the FERC to defer approximately $54 million of vegetation management costs ($13 million deferred as of December 31, 2004 pending authorization) estimated to be incurred from 2004 through 2007. The FERC approved ATSI's request to defer those costs on March 4, 2005.

ATSI and MISO filed with the FERC on December 2, 2004, seeking approval for ATSI to have transmission rates established based on a FERC-approved cost of service formula rate included in Attachment O under the MISO tariff. The ATSI Network Service net revenue requirement increased under the formula rate to approximately $159 million. On January 28, 2005, the FERC accepted for filing the revised tariff sheets to become effective February 1, 2005, subject to refund, and ordered a public hearing be held to address the reasonableness of the proposal to eliminate the voltage-differentiated rate design for the ATSI zone.

Reliability Initiatives

In 2004, we completed implementation of all actions and initiatives related to enhancing area reliability, improving voltage and reactive management, operator readiness and training, and emergency response preparedness as recommended by various governmental, industry and ad hoc reliability entities (PUCO, FERC, NERC and the U.S. - Canada Power System Outage Task Force) for completion in 2004. We certified to NERC on June 30, 2004, that we had completed our initiatives with minor exceptions noted, and an independent team led by NERC verified the implementation. Further, we reported to NERC on December 28, 2004 that the minor exceptions were essentially complete.

We are proceeding with the implementation of the recommendations that were to be completed subsequent to 2004 and will continue to periodically assess the FERC-ordered Reliability Study recommendations for forecasted 2009 system conditions recognizing revised load forecasts and other changing system conditions which may impact the recommendations. Thus far, implementation of the recommendations has not required, nor is expected to require, substantial investment in new, or material upgrades to existing equipment. We note, however, that FERC or other applicable government agencies and reliability coordinators may take a different view as to recommended enhancements or may recommend additional enhancements in the future that could require additional, material expenditures. Finally, the PUCO is continuing to review our filing that addressed upgrades to control room computer hardware and software and enhancements to the training of control room operators, before determining the next steps, if any, in the proceeding. See Note 9 to the consolidated financial statements for a more detailed discussion of reliability initiatives, including actions by the PPUC that impact Met-Ed, Penelec and Penn.

On July 5, 2003, JCP&L experienced a series of 34.5 kilovolt sub-transmission line faults that resulted in outages on the New Jersey shore. As a result of an investigation into these outages, the NJBPU issued an order to JCP&L on July 23, 2004 to implement actions to improve reliability in accordance with a Special Reliability Master (SRM) report findings and an operations audit.

See Note 9 to the consolidated financial statements for a more detailed discussion of reliability initiatives, including actions by the PPUC, that impact Met-Ed, Penelec and Penn.

ENVIRONMENTAL MATTERS

We believe we are in compliance with current SO_2 and NO_x reduction requirements under the Clean Air Act Amendments of 1990. In 1998, the EPA finalized regulations requiring additional NO_x reductions from the Companies' Ohio and Pennsylvania facilities. Various regulatory and judicial actions have since sought to further define NO_x

reduction requirements (see Note 13(C) – Environmental Matters). We continue to evaluate our compliance plans and other compliance options.

Clean Air Act Compliance

The Companies are required to meet federally approved SO2 regulations. Violations of such regulations can result in shutdown of the generating unit involved and/or civil or criminal penalties of up to $32,500 for each day the unit is in violation. The EPA has an interim enforcement policy for SO2 regulations in Ohio that allows for compliance based on a 30-day averaging period. The Companies cannot predict what action the EPA may take in the future with respect to the interim enforcement policy.

The Companies believe they are complying with SO2 reduction requirements under the Clean Air Act Amendments of 1990 by burning lower-sulfur fuel, generating more electricity from lower-emitting plants, and/or using emission allowances. NOx reductions required by the 1990 Amendments are being achieved through combustion controls and the generation of more electricity at lower-emitting plants. In September 1998, the EPA finalized regulations requiring additional NOx reductions from the Companies' facilities. The EPA's NOx Transport Rule imposes uniform reductions of NOx emissions (an approximate 85% reduction in utility plant NOx emissions from projected 2007 emissions) across a region of nineteen states (including Michigan, New Jersey, Ohio and Pennsylvania) and the District of Columbia based on a conclusion that such NOx emissions are contributing significantly to ozone levels in the eastern United States. The Companies believe their facilities are also complying with NOx budgets established under State Implementation Plans (SIP) through combustion controls and post-combustion controls, including Selective Catalytic Reduction and Selective Non-Catalytic Reduction systems, and/or using emission allowances.

National Ambient Air Quality Standards

In July 1997, the EPA promulgated changes in the NAAQS for ozone and proposed a new NAAQS for fine particulate matter. On December 17, 2003, the EPA proposed the "Interstate Air Quality Rule" covering a total of 29 states (including Michigan, New Jersey, Ohio and Pennsylvania) and the District of Columbia based on proposed findings that air pollution emissions from 29 eastern states and the District of Columbia significantly contribute to nonattainment of the NAAQS for fine particles and/or the "8-hour" ozone NAAQS in other states. The EPA has proposed the Interstate Air Quality Rule to "cap-and-trade" NOx and SO2 emissions in two phases (Phase I in 2010 and Phase II in 2015). According to the EPA, SO2 emissions would be reduced by approximately 3.6 million tons annually by 2010, across states covered by the rule, with reductions ultimately reaching more than 5.5 million tons annually. NOx emission reductions would measure about 1.5 million tons in 2010 and 1.8 million tons in 2015. The future cost of compliance with these proposed regulations may be substantial and will depend on whether and how they are ultimately implemented by the states in which the Companies operate affected facilities.

Mercury Emissions

In December 2000, the EPA announced it would proceed with the development of regulations regarding hazardous air pollutants from electric power plants, identifying mercury as the hazardous air pollutant of greatest concern. On December 15, 2003, the EPA proposed two different approaches to reduce mercury emissions from coal-fired power plants. The first approach would require plants to install controls known as MACT based on the type of coal burned. According to the EPA, if implemented, the MACT proposal would reduce nationwide mercury emissions from coal-fired power plants by 14 tons to approximately 34 tons per year. The second approach proposes a cap-and-trade program that would reduce mercury emissions in two distinct phases. Initially, mercury emissions would be reduced by 2010 as a "co-benefit" from implementation of SO2 and NOx emission caps under the EPA's proposed Interstate Air Quality Rule. Phase II of the mercury cap-and-trade program would be implemented in 2018 to cap nationwide mercury emissions from coal-fired power plants at 15 tons per year. The EPA has agreed to choose between these two options and issue a final rule by March 15, 2005. The future cost of compliance with these regulations may be substantial.

W. H. Sammis Plant

In 1999 and 2000, the EPA issued NOV or Compliance Orders to nine utilities covering 44 power plants, including the W. H. Sammis Plant, which is owned by OE and Penn. In addition, the U.S. Department of Justice filed eight civil complaints against various investor-owned utilities, which included a complaint against OE and Penn in the U.S. District Court for the Southern District of Ohio. These cases are referred to as New Source Review cases. The NOV and complaint allege violations of the Clean Air Act based on operation and maintenance of the W. H. Sammis Plant dating back to 1984. The complaint requests permanent injunctive relief to require the installation of "best available control technology" and civil penalties of up to $27,500 per day of violation. On August 7, 2003, the United States District Court for the Southern District of Ohio ruled that 11 projects undertaken at the W. H. Sammis Plant between 1984 and 1998 required pre-construction permits under the Clean Air Act. The ruling concludes the liability phase of the case, which deals with applicability of Prevention of Significant Deterioration provisions of the Clean Air Act. The remedy phase of the trial to address any civil penalties and what, if any, actions should be taken to further reduce emissions at the plant has been delayed without rescheduling by the Court because the parties are engaged in meaningful settlement negotiations. The Court indicated, in its August 2003 ruling, that the remedies it "may consider and impose involved a much broader, equitable analysis, requiring the Court to consider air quality, public health, economic impact, and employment consequences. The Court may also consider the less than consistent efforts of the EPA to apply and further enforce the Clean Air Act." The potential penalties that may be imposed, as well as the capital expenditures necessary to comply with substantive remedial measures that may be required, could have a material adverse impact on FirstEnergy's, OE's and Penn's respective financial condition and results of operations. While the parties are engaged in meaningful settlement discussions, management is unable to predict the ultimate outcome of this matter and no liability has been accrued as of December 31, 2004.

Regulation of Hazardous Waste

As a result of the Resource Conservation and Recovery Act of 1976, as amended, and the Toxic Substances Control Act of 1976, federal and state hazardous waste regulations have been promulgated. Certain fossil-fuel combustion waste products, such as coal ash, were exempted from hazardous waste disposal requirements pending the EPA's evaluation of the need for future regulation. The EPA subsequently determined that regulation of coal ash, as a hazardous waste is unnecessary. In April 2000, the EPA announced that it will develop national standards regulating disposal of coal ash under its authority to regulate nonhazardous waste.

The Companies have been named as PRPs at waste disposal sites, which may require cleanup under the Comprehensive Environmental Response, Compensation and Liability Act of 1980. Allegations of disposal of hazardous substances at historical sites and the liability involved are often unsubstantiated and subject to dispute; however, federal law provides that all PRPs for a particular site are liable on a joint and several basis. Therefore, environmental liabilities that are considered probable have been recognized on the Consolidated Balance Sheets as of December 31, 2004, based on estimates of the total costs of cleanup, the Companies' proportionate responsibility for such costs and the financial ability of other nonaffiliated entities to pay. In addition, JCP&L has accrued liabilities for environmental remediation of former manufactured gas plants in New Jersey; those costs are being recovered by JCP&L through a non-bypassable SBC. Included in Current Liabilities and Other Noncurrent Liabilities are accrued liabilities aggregating approximately $65 million as of December 31, 2004. The Companies accrue environmental liabilities only when they can conclude that it is probable that they have an obligation for such costs and can reasonably determine the amount of such costs. Unasserted claims are reflected in the Companies' determination of environmental liabilities and are accrued in the period that they are both probable and reasonably estimable.

Climate Change

In December 1997, delegates to the United Nations' climate summit in Japan adopted an agreement, the Kyoto Protocol (Protocol), to address global warming by reducing the amount of man-made greenhouse gases emitted by developed countries by 5.2% from 1990 levels between 2008 and 2012. The United States signed the Protocol in 1998 but it failed to receive the two-thirds vote of the United States Senate required for ratification. However, the Bush administration has committed the United States to a voluntary climate change strategy to reduce domestic greenhouse gas intensity – the ratio of emissions to economic output – by 18% through 2012.

The Companies cannot currently estimate the financial impact of climate change policies, although the potential restrictions on CO_2 emissions could require significant capital and other expenditures. However, the CO_2 emissions per kilowatt-hour of electricity generated by the Companies is lower than many regional competitors due to the Companies' diversified generation sources which includes low or non-CO_2 emitting gas-fired and nuclear generators.

Clean Water Act

Various water quality regulations, the majority of which are the result of the federal Clean Water Act and its amendments, apply to the Companies' plants. In addition, Ohio, New Jersey and Pennsylvania have water quality standards applicable to the Companies' operations. As provided in the Clean Water Act, authority to grant federal National Pollutant Discharge Elimination System water discharge permits can be assumed by a state. Ohio, New Jersey and Pennsylvania have assumed such authority.

On September 7, 2004, the EPA established new performance standards under Clean Water Act Section 316(b) for reducing impacts on fish and shellfish from cooling water intake structures at certain existing large electric generating plants. The regulations call for reductions in impingement mortality, when aquatic organisms are pinned against screens or other parts of a cooling water intake system and entrainment, which occurs when aquatic species are drawn into a facility's cooling water system. The Companies are conducting comprehensive demonstration studies, due in 2008, to determine the operational measures, equipment or restoration activities, if any, necessary for compliance by their facilities with the performance standards. FirstEnergy is unable to predict the outcome of such studies. Depending on the outcome of such studies, the future cost of compliance with these standards may require material capital expenditures.

OTHER LEGAL PROCEEDINGS

Power Outages and Related Litigation

Three substantially similar actions were filed in various Ohio state courts by plaintiffs seeking to represent customers who allegedly suffered damages as a result of the August 14, 2003 power outages. All three cases were dismissed for lack of jurisdiction. One case was refiled at the PUCO. The other two cases were appealed. One case was dismissed and no further appeal was sought. The remaining case is pending. In addition to the one case that was refiled at the PUCO, the Ohio Companies were named as respondents in a regulatory proceeding that was initiated at the PUCO in response to complaints alleging failure to provide reasonable and adequate service stemming primarily from the August 14, 2003 power outages.

One complaint has been filed against FirstEnergy in the New York State Supreme Court. In this case, several plaintiffs in the New York City metropolitan area allege that they suffered damages as a result of the August 14, 2003 power outages. None of the plaintiffs are customers of any FirstEnergy affiliate. FirstEnergy filed a motion to dismiss with the Court on October 22, 2004. No timetable for a decision on the motion to dismiss has been established by the

Court. No damage estimate has been provided and thus potential liability has not been determined.

FirstEnergy is vigorously defending these actions, but cannot predict the outcome of any of these proceedings or whether any further regulatory proceedings or legal actions may be initiated against the Companies. In particular, if FirstEnergy or its subsidiaries were ultimately determined to have legal liability in connection with these proceedings, it could have a material adverse effect on FirstEnergy's or its subsidiaries' financial condition and results of operations.

Nuclear Plant Matters

In late 2003, FENOC received a subpoena from a grand jury in the United States District Court for the Northern District of Ohio, Eastern Division requesting the production of certain documents and records relating to the inspection and maintenance of the reactor vessel head at the Davis-Besse Nuclear Power Station. FirstEnergy is unable to predict the outcome of this investigation. On December 10, 2004, FirstEnergy received a letter from the United States Attorney's Office stating that FENOC is a target of the federal grand jury investigation into alleged false statements relating to the Davis-Besse Nuclear Power Station outage made to the NRC in the Fall of 2001 in response to NRC Bulletin 2001-01. The letter also said that the designation of FENOC as a target indicates that, in the view of the prosecutors assigned to the matter, it is likely that federal charges will be returned against FENOC by the grand jury. FirstEnergy is unable to predict the outcome of this investigation. On February 10, 2005, FENOC received an additional subpoena for documents related to root cause reports regarding reactor head degradation and the assessment of reactor head management issues at Davis-Besse. In addition, FENOC remains subject to possible civil enforcement action by the NRC in connection with the events leading to the Davis-Besse outage in 2002.

On August 12, 2004, the NRC notified FENOC that it will increase its regulatory oversight of the Perry Nuclear Power Plant as a result of problems with safety system equipment over the past two years. FENOC operates the Perry Nuclear Power Plant, which is either owned or leased by OE, CEI, TE and Penn. Although the NRC noted that the plant continues to operate safely, the agency has indicated that its increased oversight will include an extensive NRC team inspection to assess the equipment problems and the sufficiency of FENOC's corrective actions. The outcome of these matters could include NRC enforcement action or other impacts on operating authority. As a result, these matters could have a material adverse effect on FirstEnergy's or its subsidiaries' financial condition.

Other Legal Matters

Various lawsuits, claims (including claims for asbestos exposure) and proceedings related to FirstEnergy's normal business operations are pending against FirstEnergy and its subsidiaries. The most significant not otherwise discussed above are described below.

On July 27, 2004, FirstEnergy announced that it had reached an agreement to resolve pending lawsuits alleging violations of federal securities laws and related state laws filed against FirstEnergy in connection with, among other things, the restatements in August 2003 by FirstEnergy and the Ohio Companies of previously reported results, the August 14, 2003 power outages and the extended outage at the Davis-Besse Nuclear Power Station. The settlement agreement, which does not constitute any admission of wrongdoing, provides for a total settlement payment of \$89.9 million. Of that amount, FirstEnergy's insurance carriers paid \$71.92 million, based on a contractual pre-allocation, and FirstEnergy paid \$17.98 million, which resulted in an after-tax charge against FirstEnergy's second quarter earnings of \$11 million or \$0.03 per share of common stock (basic and diluted). On December 30, 2004, the court approved the settlement.

On October 20, 2004, FirstEnergy was notified by the SEC that the previously disclosed informal inquiry initiated by the SEC's Division of Enforcement in September 2003 relating to the restatements in August 2003 of previously reported results by FirstEnergy and the Ohio Companies, and the Davis-Besse extended outage, have become the subject of a formal order of investigation. The SEC's formal order of investigation also encompasses issues raised during the SEC's examination of FirstEnergy and the Companies under the PUHCA. Concurrent with this notification, FirstEnergy received a subpoena asking for background documents and documents related to the restatements and Davis-Besse issues. On December 30, 2004, FirstEnergy received a second subpoena asking for documents relating to issues raised during the SEC's PUHCA examination. FirstEnergy has cooperated fully with the informal inquiry and will continue to do so with the formal investigation.

If it were ultimately determined that FirstEnergy or its subsidiaries have legal liability or are otherwise made subject to liability based on the above matter, it could have a material adverse effect on FirstEnergy's or its subsidiaries' financial condition and results of operations.

CRITICAL ACCOUNTING POLICIES

We prepare our consolidated financial statements in accordance with GAAP. Application of these principles often requires a high degree of judgment, estimates and assumptions that affect financial results. All of our assets are subject to their own specific risks and uncertainties and are regularly reviewed for impairment. Our more significant accounting policies are described below.

Regulatory Accounting

Our regulated services segment is subject to regulation that sets the prices (rates) we are permitted to charge our customers based on costs that the regulatory agencies determine we are permitted to recover. At times, regulators permit the future recovery through rates of costs that would be currently charged to expense by an unregulated company. This ratemaking process results in the recording of regulatory assets based on anticipated future cash inflows. We regularly review these assets to assess their ultimate recoverability within the approved regulatory guidelines. Impairment risk associated with these assets relates to potentially adverse legislative, judicial or regulatory actions in the future.

Revenue Recognition

We follow the accrual method of accounting for revenues, recognizing revenue for electricity that has been delivered to customers but not yet billed through the end of the accounting period. The determination of electricity sales to individual customers is based on meter readings, which occur on a systematic basis throughout the month. At the end of each month, electricity delivered to customers since the last meter reading is estimated and a corresponding accrual for unbilled sales is recognized. The determination of unbilled sales requires management to make estimates regarding electricity available for retail load, transmission and distribution line losses, demand by customer class, weather-related impacts, prices in effect for each customer class and electricity provided by alternative suppliers.

Pension and Other Postretirement Benefits Accounting

Our reported costs of providing non-contributory defined pension benefits and postemployment benefits other than pensions are dependent upon numerous factors resulting from actual plan experience and certain assumptions.

Pension and OPEB costs are affected by employee demographics (including age, compensation levels, and employment periods), the level of contributions we make to the plans, and earnings on plan assets. Such factors may be further affected by business combinations, which impact employee demographics, plan experience and other factors. Pension and OPEB costs are also affected by changes to key assumptions, including anticipated rates of return on plan assets, the discount rates and health care trend rates used in determining the projected benefit obligations for pension and OPEB costs.

In accordance with SFAS 87, changes in pension and OPEB obligations associated with these factors may not be immediately recognized as costs on the income statement, but generally are recognized in future years over the remaining average service period of plan participants. SFAS 87 and SFAS 106 delay recognition of changes due to the long-term nature of pension and OPEB obligations and the varying market conditions likely to occur over long periods of time. As such, significant portions of pension and OPEB costs recorded in any period may not reflect the actual level of cash benefits provided to plan participants and are significantly influenced by assumptions about future market conditions and plan participants' experience.

In selecting an assumed discount rate, we consider currently available rates of return on high-quality fixed income investments expected to be available during the period to maturity of the pension and other postretirement benefit obligations. Due to recent declines in corporate bond yields and interest rates in general, we reduced the assumed discount rate as of December 31, 2004 to 6.00% from 6.25% and 6.75% used as of December 31, 2003 and 2002, respectively.

Our assumed rate of return on pension plan assets considers historical market returns and economic forecasts for the types of investments held by our pension trusts. In 2004, 2003 and 2002, plan assets actually earned 11.1%, 24.2% and (11.3)%, respectively. Our pension costs in 2004 were computed assuming a 9.0% rate of return on plan assets based upon projections of future returns and our pension trust investment allocation of approximately 68% equities, 29% bonds, 2% real estate and 1% cash.

In the third quarter of 2004, we made a $500 million voluntary contribution to our pension plan. Prior to this contribution, projections indicated that cash contributions of approximately $600 million would have been required during the 2006 to 2007 time period under minimum funding requirements established by the IRS. Our election to pre-fund the plan is expected to eliminate that funding requirement.

As a result of our voluntary contribution and the increased market value of pension plan assets, we reduced our accrued benefit cost as of December 31, 2004 by $424 million. As prescribed by SFAS 87, we reduced our additional minimum liability by $15 million, recording a decrease in an intangible asset of $9 million and crediting OCI by $6 million. The balance in AOCL of $296 million (net of $208 million in deferred taxes) will reverse in future periods to the extent the fair value of trust assets exceeds the accumulated benefit obligation.

Health care cost trends have significantly increased and will affect future OPEB costs. The 2004 and 2005 composite health care trend rate assumptions are approximately 10%-12% and 9%-11%, respectively, gradually decreasing to 5% in later years. In determining our trend rate assumptions, we included the specific provisions of our health care plans, the demographics and utilization rates of plan participants, actual cost increases experienced in our health care plans, and projections of future medical trend rates. The effect on our pension and OPEB costs and liabilities from changes in key assumptions are as follows:

Increase in Costs from Adverse Changes in Key Assumptions

Assumption	Adverse Change	Pension	OPEB	Total
		(In millions)		
Discount rate	Decrease by 0.25%	$10	$5	$15
Long-term return on assets	Decrease by 0.25%	$10	$1	$11
Health care trend rate	Increase by 1%	na	$19	$19
Increase in Minimum Liability				
Discount rate	Decrease by 0.25%	$110	na	$110

Ohio Transition Cost Amortization

In connection with the Ohio Companies' transition plan, the PUCO determined allowable transition costs based on amounts recorded on the regulatory books of the Ohio Companies. These costs exceeded those deferred or capitalized on FirstEnergy's balance sheet prepared under GAAP since they included certain costs which had not yet been incurred or that were recognized on the regulatory financial statements (fair value purchase accounting adjustments). FirstEnergy uses an effective interest method for amortizing its transition costs, often referred to as a "mortgage-style" amortization. The interest rate under this method is equal to the rate of return authorized by the PUCO in the transition plan for each respective company. In computing the transition cost amortization, FirstEnergy includes only the portion of the transition revenues associated with transition costs included on the balance sheet prepared under GAAP. Revenues collected for the off-balance sheet costs and the return associated with these costs are recognized as income when received.

Long-Lived Assets

In accordance with SFAS 144, we periodically evaluate our long-lived assets to determine whether conditions exist that would indicate that the carrying value of an asset might not be fully recoverable. The accounting standard requires that if the sum of future cash flows (undiscounted) expected to result from an asset is less than the carrying value of the asset, an asset impairment must be recognized in the financial statements. If impairment has occurred, we recognize a loss – calculated as the difference between the carrying value and the estimated fair value of the asset (discounted future net cash flows).

The calculation of future cash flows is based on assumptions, estimates and judgment about future events. The aggregate amount of cash flows determines whether an impairment is indicated. The timing of the cash flows is critical in determining the amount of the impairment.

Nuclear Decommissioning

In accordance with SFAS 143, we recognize an ARO for the future decommissioning of our nuclear power plants. The ARO liability represents an estimate of the fair value of our current obligation related to nuclear decommissioning and the retirement of other assets. A fair value measurement inherently involves uncertainty in the amount and timing of settlement of the liability. We used an expected cash flow approach to measure the fair value of the nuclear decommissioning ARO. This approach applies probability weighting to discounted future cash flow scenarios that reflect a range of possible outcomes. The scenarios consider settlement of the ARO at the expiration of the nuclear power plants' current license and settlement based on an extended license term.

Goodwill

In a business combination, the excess of the purchase price over the estimated fair values of the assets acquired and liabilities assumed is recognized as goodwill. Based on the guidance provided by SFAS 142, we evaluate goodwill for impairment at least annually and make such evaluations more frequently if indicators of impairment arise. In accordance with the accounting standard, if the fair value of a reporting unit is less than its carrying value (including goodwill), the goodwill is tested for impairment. If an impairment is indicated we recognize a loss – calculated as the difference between the implied fair value of a reporting unit's goodwill and the carrying value of the goodwill. Our annual review was completed in the third quarter of 2004 with no impairment indicated.

SFAS 142 requires the goodwill of a reporting unit to be tested for impairment if there is a more-likely-than-not expectation that the reporting unit or a significant asset group within the reporting unit will be sold. In December 2004, the FSG subsidiaries qualified as held for sale in accordance with SFAS 144. As required by SFAS 142, the goodwill of FSG was tested for impairment, resulting in a non-cash charge of $36 million in the fourth quarter of 2004.

The forecasts used in our evaluations of goodwill reflect operations consistent with our general business assumptions. Unanticipated changes in those assumptions could have a significant effect on our future evaluations of goodwill.

NEW ACCOUNTING STANDARDS AND INTERPRETATIONS

SFAS 123 (revised 2004) "Share-Based Payment"

In December 2004, the FASB issued this revision to SFAS 123, which requires expensing stock options in the financial statements. Important to applying the new standard is understanding how to (1) measure the fair value of stock-based compensation awards and (2) recognize the related compensation cost for those awards. For an award to qualify for equity classification, it must meet certain criteria in SFAS 123(R). An award that does not meet those criteria will be classified as a liability and remeasured each period. SFAS 123(R) retains SFAS 123's requirements on accounting for income tax effects of stock-based compensation. The effective date for FirstEnergy is July 1, 2005 and the Company will be applying modified prospective application, without restatement of prior interim periods. Any potential cumulative adjustments have not been determined. FirstEnergy uses the Black-Scholes option pricing model to value options and will continue to do so upon adoption of SFAS 123(R). The impacts of the fair value recognition provisions of SFAS 123 on FirstEnergy's net income and earnings per share for 2002 through 2004 are disclosed in Note 4 to the consolidated financial statements. FirstEnergy is considering alternative compensation strategies in conjunction with the adoption of SFAS 123(R).

EITF Issue No. 03-1, "The Meaning of Other-Than-Temporary Impairment and its Application to Certain Investments"

In March 2004, the EITF reached a consensus on the application guidance for EITF 03-1, which provides a model for determining when investments in certain debt and equity securities are considered other than temporarily impaired. When an impairment is other-than-temporary, the investment must be measured at fair value and the impairment loss recognized in earnings. The recognition and measurement provisions of EITF 03-1, which were to be effective for periods beginning after June 15, 2004, were delayed by the issuance of FSP EITF 03-1-1 in September 2004. During the period of delay, FirstEnergy will continue to evaluate its investments as required by existing authoritative guidance.

CONSOLIDATED STATEMENTS OF INCOME

(In thousands, except per share amounts)

For the Years Ended December 31,	2004	2003	2002
Revenues:			
Electric utilities	**$9,064,853**	$8,962,201	$9,165,805
Unregulated businesses	**3,388,193**	2,712,687	2,287,549
Total revenues	**12,453,046**	11,674,888	11,453,354
Expenses:			
Fuel and purchased power	**4,469,484**	4,159,143	3,309,658
Other operating expenses	**3,558,676**	3,796,062	3,927,370
Provision for depreciation	**589,652**	606,436	721,493
Amortization of regulatory assets	**1,166,323**	1,079,337	940,991
Deferral of new regulatory assets	**(256,795)**	(194,261)	(183,947)
Goodwill impairment (Note 2(H))	**36,471**	116,988	—
General taxes	**677,757**	637,967	649,400
Total expenses	**10,241,568**	10,201,672	9,364,965
Claim Settlement (Note 8)	—	167,937	—
Income Before Interest and Income Taxes	**2,211,478**	1,641,153	2,088,389
Net Interest Charges:			
Interest expense	**670,945**	798,911	904,697
Capitalized interest	**(25,581)**	(31,900)	(24,474)
Subsidiaries' preferred stock dividends	**21,413**	42,369	75,647
Net interest charges	**666,777**	809,380	955,870
Income Taxes	**670,922**	407,524	514,134
Income Before Discontinued Operations and Cumulative Effect of Accounting Change	**873,779**	424,249	618,385
Discontinued operations (net of income taxes (benefit) of $3,038,000, ($3,064,000) and $14,560,000, respectively) (Note 2(J))	**4,396**	(103,632)	(65,581)
Cumulative effect of accounting change (net of income taxes of $72,516,000) (Note 2(K))	—	102,147	—
Net Income	**$ 878,175**	$ 422,764	$ 552,804
Basic Earnings Per Share of Common Stock:			
Income before discontinued operations and cumulative effect of accounting change	**$ 2.67**	$ 1.40	$ 2.11
Discontinued operations (Note 2(J))	**0.01**	(0.34)	(0.22)
Cumulative effect of accounting change (Note 2(K))	—	0.33	—
Net income	**$ 2.68**	$ 1.39	$ 1.89
Weighted Average Number of Basic Shares Outstanding	**327,387**	303,582	293,194
Diluted Earnings Per Share of Common Stock:			
Income before discontinued operations and cumulative effect of accounting change	**$ 2.66**	$ 1.40	$ 2.10
Discontinued operations (Note 2(J))	**0.01**	(0.34)	(0.22)
Cumulative effect of accounting change (Note 2(K))	—	0.33	—
Net income	**$ 2.67**	$ 1.39	$ 1.88
Weighted Average Number of Diluted Shares Outstanding	**328,982**	304,972	294,421

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

CONSOLIDATED BALANCE SHEETS

As of December 31,	2004	2003
		(In thousands)
ASSETS		
Current Assets:		
Cash and cash equivalents	**$ 52,941**	$ 113,975
Receivables-		
Customers (less accumulated provisions of $34,476,000 and $50,247,000 respectively, for uncollectible accounts)	**979,242**	1,000,259
Other (less accumulated provisions of $26,070,000 and $18,283,000 respectively, for uncollectible accounts)	**377,195**	505,241
Materials and supplies, at average cost-		
Owned	**363,547**	325,303
Under consignment	**94,226**	95,719
Prepayments and other	**145,196**	202,814
	2,012,347	2,243,311
Property, Plant and Equipment:		
In service	**22,213,218**	21,594,746
Less—Accumulated provision for depreciation	**9,413,730**	9,105,303
	12,799,488	12,489,443
Construction work in progress	**678,868**	779,479
	13,478,356	13,268,922
Investments:		
Nuclear plant decommissioning trusts	**1,582,588**	1,351,650
Investments in lease obligation bonds (Note 6)	**951,352**	989,425
Certificates of deposit (Note 10(C))	**—**	277,763
Other	**740,026**	878,853
	3,273,966	3,497,691
Deferred Charges:		
Regulatory assets	**5,532,087**	7,076,923
Goodwill	**6,050,277**	6,127,883
Other	**720,911**	695,218
	12,303,275	13,900,024
	$ 31,067,944	$ 32,909,948
LIABILITIES AND CAPITALIZATION		
Current Liabilities:		
Currently payable long-term debt	**$ 940,944**	$ 1,754,197
Short-term borrowings (Note 12)	**170,489**	521,540
Accounts payable	**610,589**	725,239
Accrued taxes	**657,219**	669,529
Other	**929,194**	801,662
	3,308,435	4,472,167
Capitalization (See Consolidated Statement of Capitalization):		
Common stockholders' equity	**8,589,294**	8,289,341
Preferred stock of consolidated subsidiaries not subject to mandatory redemption	**335,123**	335,123
Long-term debt and other long-term obligations	**10,013,349**	9,789,066
	18,937,766	18,413,530
Noncurrent Liabilities:		
Accumulated deferred income taxes	**2,324,097**	2,178,075
Asset retirement obligations (Note 11)	**1,077,557**	1,179,493
Power purchase contract loss liability	**2,001,006**	2,727,892
Retirement benefits	**1,238,973**	1,591,006
Lease market valuation liability	**936,200**	1,021,000
Other	**1,243,910**	1,326,785
	8,821,743	10,024,251
Commitments, Guarantees and Contingencies (Notes 6 and 13)	**$ 31,067,944**	$ 32,909,948

The accompanying Notes to Consolidated Financial Statements are an integral part of these balance sheets.

CONSOLIDATED STATEMENTS OF CAPITALIZATION

(Dollars In thousands, except for share amounts)

As of December 31,	2004	2003
Common Stockholders' Equity:		
Common stock, $0.10 par value -authorized 375,000,000 shares- 329,836,276 shares outstanding	**$ 32,984**	$ 32,984
Other paid-in capital	**7,055,676**	7,062,825
Accumulated other comprehensive loss (Note 2(I))	**(313,112)**	(352,649)
Retained earnings (Note 10(A))	**1,856,863**	1,604,385
Unallocated employee stock ownership plan common stock- 2,032,800 and 2,896,951 shares, respectively (Note 4(B))	**(43,117)**	(58,204)
Total common stockholders' equity	**8,589,294**	8,289,341

	Number of Shares Outstanding		Optional Redemption Price			
	2004	2003	Per Share	Aggregate		
Preferred Stock of Consolidated Subsidiaries Not Subject To Mandatory Redemption (Note 10(B)):						
Ohio Edison Company Cumulative, $100 par value-Authorized 6,000,000 shares						
3.90%	152,510	152,510	$ 103.63	$ 15,804	**15,251**	15,251
4.40%	176,280	176,280	108.00	19,038	**17,628**	17,628
4.44%	136,560	136,560	103.50	14,134	**13,656**	13,656
4.56%	144,300	144,300	103.38	14,917	**14,430**	14,430
Total	609,650	609,650		$ 63,893	**60,965**	60,965
Pennsylvania Power Company Cumulative, $100 par value-Authorized 1,200,000 shares						
4.24%	40,000	40,000	103.13	4,125	**4,000**	4,000
4.25%	41,049	41,049	105.00	4,310	**4,105**	4,105
4.64%	60,000	60,000	102.98	6,179	**6,000**	6,000
7.75%	250,000	250,000	100.00	25,000	**25,000**	25,000
Total	391,049	391,049		39,614	**39,105**	39,105
Cleveland Electric Illuminating Company Cumulative, without par value-Authorized 4,000,000 shares						
$ 7.40 Series A	500,000	500,000	101.00	50,500	**50,000**	50,000
Adjustable Series L	474,000	474,000	100.00	47,400	**46,404**	46,404
Total	974,000	974,000		97,900	**96,404**	96,404
Toledo Edison Company Cumulative, $100 par value-Authorized 3,000,000 shares						
$4.25	160,000	160,000	104.63	16,740	**16,000**	16,000
$4.56	50,000	50,000	101.00	5,050	**5,000**	5,000
$4.25	100,000	100,000	102.00	10,200	**10,000**	10,000
	310,000	310,000		31,990	**31,000**	31,000
Cumulative, $25 par value-Authorized 12,000,000 shares						
$2.365	1,400,000	1,400,000	27.75	38,850	**35,000**	35,000
Adjustable Series A	1,200,000	1,200,000	25.00	30,000	**30,000**	30,000
Adjustable Series B	1,200,000	1,200,000	25.00	30,000	**30,000**	30,000
	3,800,000	3,800,000		98,850	**95,000**	95,000
Total	4,110,000	4,110,000		130,840	**126,000**	126,000
Jersey Central Power & Light Company Cumulative, $100 stated value-Authorized 15,600,000 shares						
4.00% Series	125,000	125,000	106.50	13,313	**12,649**	12,649

Long-Term Debt and Other Long-Term Obligations (Note 10(C)) *(Interest rates reflect weighted average rates)* *(In thousands)*

	First Mortgage Bonds			Secured Notes			Unsecured Notes			Total	
As of December 31,		**2004**	**2003**		**2004**	**2003**		**2004**	**2003**	**2004**	**2003**
Ohio Edison Co.-											
Due 2004-2009	6.88%	$80,000	$80,000	7.61%	$ 67,476	$ 229,257	4.46%	$ 175,000	$ 526,725		
Due 2010-2014	—	—	—	7.16%	1,257	1,256	3.70%	50,000	—		
Due 2015-2019	—	—	—	3.80%	156,725	59,000	5.04%	206,000	150,000		
Due 2020-2024	—	—	—	7.01%	60,443	60,443	3.87%	50,000	—		
Due 2025-2029	—	—	—	5.75%	119,734	13,522	—	—	—		
Due 2030-2034	—	—	—	2.19%	359,800	308,012	3.35%	30,000	—		
Total-Ohio Edison		80,000	80,000		765,435	671,490		511,000	676,725	**$1,356,435**	$1,428,215
Cleveland Electric Illuminating Co.-											
Due 2004-2009	6.86%	125,000	125,000	7.29%	271,700	622,485	—	—	27,700		
Due 2010-2014	—	—	—	—	—	—	5.72%	378,700	378,700		
Due 2015-2019	—	—	—	6.23%	412,630	412,630	—	—	—		
Due 2020-2024	—	—	—	5.35%	180,560	186,660	—	—	—		
Due 2025-2029	—	—	—	7.59%	148,843	148,843	—	—	—		
Due 2030-2034	—	—	—	2.79%	180,995	30,000	7.87%	130,793	103,093		
Total-Cleveland Electric		125,000	125,000		1,194,728	1,400,618		509,493	509,493	**1,829,221**	2,035,111
Toledo Edison Co.-											
Due 2004-2009	—	—	145,000	7.13%	30,000	100,000	—	—	85,250		
Due 2020-2024	—	—	—	5.37%	166,300	144,500	—	—	—		
Due 2025-2029	—	—	—	5.90%	13,851	13,851	—	—	—		
Due 2030-2034	—	—	—	2.01%	81,600	51,100	3.90%	90,950	—		
Total-Toledo Edison		—	145,000		291,751	309,451		90,950	85,250	**382,701**	539,701
Pennsylvania Power Co.-											
Due 2004-2009	9.74%	4,870	40,344	—	—	10,300	—	—	19,700		
Due 2010-2014	9.74%	4,870	4,870	5.40%	1,000	1,000	—	—	—		
Due 2015-2019	9.74%	4,903	4,903	4.24%	45,325	45,325	—	—	—		
Due 2020-2024	7.63%	6,500	33,750	3.94%	27,182	27,182	—	—	—		
Due 2025-2029	—	—	—	4.93%	33,472	23,172	3.38%	14,500	—		
Due 2030-2034	—	—	—	2.04%	5,200	—	—	—	—		
Total-Penn Power		21,143	83,867		112,179	106,979		14,500	19,700	**147,822**	210,546
Jersey Central Power & Light Co.-											
Due 2004-2009	6.89%	45,985	256,300	5.79%	240,391	255,980	—	—	124		
Due 2010-2014	—	—	—	5.84%	117,735	117,735	—	—	155		
Due 2015-2019	7.10%	12,200	12,200	5.46%	522,486	222,486	—	—	224		
Due 2020-2024	7.50%	125,000	205,000	—	—	—	—	—	325		
Due 2025-2029	7.18%	200,000	200,000	—	—	—	—	—	471		
Due 2030-2034	—	—	—	—	—	—	—	—	682		
Due 2035-2039	—	—	—	—	—	—	—	—	987		
Total-Jersey Central		383,185	673,500		880,612	596,201		—	2,968	**1,263,797**	1,272,669
Metropolitan Edison Co.-											
Due 2004-2009	6.61%	37,830	128,265	—	—	150,000	5.79%	150,000	248		
Due 2010-2014	—	—	—	—	—	250,000	4.81%	500,000	310		
Due 2015-2019	—	—	—	—	—	—	—	—	449		
Due 2020-2024	6.10%	28,500	28,500	—	—	—	—	—	650		
Due 2025-2029	5.95%	13,690	13,690	—	—	—	—	—	941		
Due 2030-2034	—	—	—	—	—	—	—	—	1,364		
Due 2035-2039	—	—	—	—	—	—	—	—	97,685		
Total-Metropolitan Edison		80,020	170,455		—	400,000		650,000	101,647	**730,020**	672,102

Long-Term Debt and Other Long-Term Obligations *(Interest rates reflect weighted average rates)* *(In thousands)*

	First Mortgage Bonds			Secured Notes			Unsecured Notes			Total	
As of December 31,		**2004**	**2003**		**2004**	**2003**		**2004**	**2003**	**2004**	**2003**
Pennsylvania Electric Co.-											
Due 2004-2009	6.12%	$ 3,495	$ 3,700	—	$ —	$ —	6.23%	$ 108,000	$ 233,124		
Due 2010-2014	5.35%	24,310	24,310	—	—	—	5.63%	185,000	35,155		
Due 2015-2019	—	—	—	—	—	—	6.63%	125,000	125,224		
Due 2020-2024	5.80%	20,000	20,000	—	—	—	—	—	325		
Due 2025-2029	6.05%	25,000	25,000	—	—	—	—	—	470		
Due 2030-2034	—	—	—	—	—	—	—	—	682		
Due 2035-2039	—	—	—	—	—	—	—	—	96,508		
Total-Pennsylvania Electric		72,805	73,010		—			418,000	491,488	**$ 490,805**	$ 564,498
FirstEnergy Corp.	—										
Due 2004-2009	—	—	—	—	—	—	5.98%	1,515,000	1,570,000		
Due 2010-2014	—	—	—	—	—	—	6.45%	1,500,000	1,500,000		
Due 2030-2034		—	—	—	—	—	7.38%	1,500,000	1,500,000		
Total-FirstEnergy		—	—	—	—	—		4,515,000	4,570,000	**4,515,000**	4,570,000
Bay Shore Power		—	—	6.24%	137,500	140,600	—	—	—	**137,500**	140,600
Facilities Services Group		—	—	5.94%	7,340	7,754	—	—	—	**7,340**	7,754
FirstEnergy Generation		—	—	—	—	—	5.00%	15,000	15,000	**15,000**	15,000
FirstEnergy Properties		—	—	7.89%	9,182	9,438	—	—	—	**9,182**	9,438
Warrenton River Terminal		—	—	6.00%	220	410	—	—	—	**220**	410
First Communications		—	—	—	—	—	6.26%	5,000	5,407	**5,000**	5,407
Total		762,153	1,350,832		3,398,947	3,642,941		6,728,943	6,477,678	**10,890,043**	11,471,451
Preferred stock subject to mandatory redemption										**16,759**	18,514
Capital lease obligations										**10,732**	13,313
Net unamortized premium on debt										**36,759**	39,985
Long-term debt due within one year										**(940,944)**	(1,754,197)
Total long-term debt and other long-term obligations										**10,013,349**	9,789,066
Total Capitalization										**$18,937,766**	$18,413,530

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

CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDERS' EQUITY

(Dollars in thousands)

	Comprehensive Income	Number of Shares	Par Value	Other Paid-In Capital	Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Unallocated ESOP Common Stock
Balance, January 1, 2002		297,636,276	$29,764	$6,113,260	$(169,003)	$1,521,805	$ (97,227)
Net income	$ 552,804					552,804	
Minimum liability for unfunded retirement benefits, net of $(316,681,000) of income taxes	(449,615)				(449,615)		
Unrealized gain on derivative hedges, net of $37,458,000 of income taxes	59,187				59,187		
Unrealized loss on investments, net of $(3,796,000) of income taxes	(5,269)				(5,269)		
Currency translation adjustments	(91,448)				(91,448)		
Comprehensive income	$ 65,659						
Stock options exercised				(8,169)			
Allocation of ESOP shares				15,250			18,950
Cash dividends on common stock						(439,628)	
Balance, December 31, 2002		297,636,276	29,764	6,120,341	(656,148)	1,634,981	(78,277)
Net income	$ 422,764					422,764	
Minimum liability for unfunded retirement benefits, net of $101,950,000 of income taxes	144,236				144,236		
Unrealized loss on derivative hedges, net of $(241,000) of income taxes	(347)				(347)		
Unrealized gain on investments, net of $53,431,000 of income taxes	68,162				68,162		
Currency translation adjustments	91,448				91,448		
Comprehensive income	$ 726,263						
Stock options exercised				(3,502)			
Common stock issued		32,200,000	3,220	930,918			
Allocation of ESOP shares				15,068			20,073
Cash dividends on common stock						(453,360)	
Balance, December 31, 2003		329,836,276	32,984	7,062,825	(352,649)	1,604,385	(58,204)
Net income	$ 878,175					878,175	
Minimum liability for unfunded retirement benefits, net of $(4,698,000) of income taxes	(6,256)				(6,256)		
Unrealized gain on derivative hedges, net of $9,638,000 of income taxes	19,031				19,031		
Unrealized gain on investments, net of $19,783,000 of income taxes	26,762				26,762		
Comprehensive income	$ 917,712						
Stock options exercised				(24,174)			
Allocation of ESOP shares				17,025			15,087
Common stock dividends declared in 2004 payable in 2005						(135,168)	
Cash dividends on common stock						(490,529)	
Balance, December 31, 2004		329,836,276	$32,984	$7,055,676	$ (313,112)	$1,856,863	$ (43,117)

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

CONSOLIDATED STATEMENTS OF PREFERRED STOCK

(Dollars in thousands)

	Not Subject to Mandatory Redemption		Subject to Mandatory Redemption	
	Number of Shares	Par or Stated Value	Number of Shares	Par or Stated Value
Balance, January 1, 2002	12,449,699	$ 661,044	22,552,751	$ 624,449
Redemptions-				
7.75% Series	(4,000,000)	(100,000)		
$7.56 Series B	(450,000)	(45,071)		
$42.40 Series T	(200,000)	(96,850)		
$8.32 Series	(100,000)	(10,000)		
$7.76 Series	(150,000)	(15,000)		
$7.80 Series	(150,000)	(15,000)		
$10.00 Series	(190,000)	(19,000)		
$2.21 Series	(1,000,000)	(25,000)		
7.625% Series			(7,500)	(750)
$7.35 Series C			(10,000)	(1,000)
$90.00 Series S			(17,750)	(17,010)
8.65% Series J			(250,001)	(26,750)
7.52% Series K			(265,000)	(28,951)
9.00% Series			(4,800,000)	(120,000)
Amortization of fair market value adjustments-				
$ 7.35 Series C				(9)
$90.00 Series S				(258)
8.56% Series				(6)
7.35% Series				209
7.34% Series				214
Balance, December 31, 2002	6,209,699	335,123	17,202,500	430,138
Redemptions-				
7.625% Series			(7,500)	(750)
$7.35 Series C			(10,000)	(1,000)
8.56% Series			(5,000,000)	(125,242)
FIN 46 Deconsolidation-				
9.00% Series			(4,000,000)	(100,000)
7.35% Series			(4,000,000)	(92,618)
7.34% Series			(4,000,000)	(92,428)
Amortization of fair market value adjustments-				
$ 7.35 Series C				(7)
8.56% Series				(2)
7.35% Series				209
7.34% Series				214
Balance, December 31, 2003	6,209,699	$ 335,123	185,000	18,514*
Redemptions-				
7.625% Series			(7,500)	(750)
$7.35 Series C			(10,000)	(1,000)
Amortization of fair market value adjustments-				
$7.35 Series C				(5)
Balance, December 31, 2004	6,209,699	$ 335,123	167,500	$ 16,759*

** The December 31, 2003 and 2004 balances for Preferred Stock subject to mandatory redemption are classified as debt under SFAS 150.*

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

CONSOLIDATED STATEMENTS OF CASH FLOWS

(In thousands)

For the Years Ended December 31,	2004	2003	2002
Cash Flows From Operating Activities:			
Net Income	**$ 878,175**	$ 422,764	$ 552,804
Adjustments to reconcile net income to net cash from operating activities:			
Provision for depreciation	**589,652**	606,436	721,493
Amortization of regulatory assets	**1,166,323**	1,079,337	940,991
Deferral of new regulatory assets	**(256,795)**	(194,261)	(183,947)
Nuclear fuel and lease amortization	**96,084**	66,072	80,507
Other amortization, net	**(19,436)**	(16,278)	(16,593)
Deferred purchased power and other costs	**(416,617)**	(427,092)	(543,644)
Deferred income taxes and investment tax credits, net	**258,263**	53,639	76,786
Goodwill impairment (Note 2(H))	**36,471**	116,988	—
Disallowed regulatory assets	—	152,500	—
Investment impairments (Note 2(H))	**17,897**	43,803	50,000
Cumulative effect of accounting change	—	(174,663)	—
Deferred rents and lease market valuation liability	**(84,696)**	(119,398)	(84,800)
Revenue credits to customers	—	(71,984)	(43,016)
Accrued retirement benefit obligations	**137,742**	287,112	124,678
Accrued compensation, net	**18,397**	(84,503)	(92,197)
Tax refund related to pre-merger period	—	51,073	—
Commodity derivative transactions, net	**(48,840)**	(70,498)	(8,682)
Loss (income) from discontinued operations (see Note 2(J))	**(4,396)**	103,632	65,581
Pension trust contribution	**(500,000)**	—	—
Decrease (increase) in operating assets:			
Receivables	**154,053**	66,311	(73,392)
Materials and supplies	**(36,751)**	5,399	(29,134)
Prepayments and other current assets	**47,010**	(31,155)	133,677
Increase (decrease) in operating liabilities:			
Accounts payable	**(110,947)**	(169,652)	218,226
Accrued taxes	**(15,011)**	221,500	25,183
Accrued interest	**(41,656)**	(59,782)	(29,693)
NUG power contract restructuring	**52,800**	—	—
Other	**(40,872)**	(102,445)	47,466
Net cash provided from operating activities	**1,876,850**	1,754,855	1,932,294
Cash Flows From Financing Activities:			
New Financing-			
Common stock	—	934,138	—
Long-term debt	**961,474**	1,027,312	668,676
Short-term borrowings, net	—	—	478,520
Redemptions and Repayments-			
Preferred stock	**(1,750)**	(127,087)	(522,223)
Long-term debt	**(1,572,080)**	(2,128,567)	(1,308,814)
Short-term borrowings, net	**(351,051)**	(575,391)	—
Net controlled disbursement activity	**(2,740)**	24,689	(14,083)
Common stock dividend payments	**(490,529)**	(453,360)	(439,628)
Net cash used for financing activities	**(1,456,676)**	(1,298,266)	(1,137,552)
Cash Flows From Investing Activities:			
Property additions	**(846,221)**	(856,316)	(997,723)
Proceeds from asset sales	**214,258**	78,743	155,034
Proceeds from certificates of deposit	**277,763**	—	—
Nonutility generation trusts withdrawals (contributions)	**(50,614)**	66,327	49,044
Contributions to nuclear decommissioning trusts	**(101,483)**	(101,218)	(103,143)
Avon cash and cash equivalents (Note 8)	—	—	31,326
Net assets held for sale	—	—	(31,326)
Long-term note receivable	—	82,250	(91,335)
Cash investments (Note 5)	**27,082**	52,884	81,349
Asset retirements and transfers	**9,513**	37,580	29,619
Other investments	**(7,993)**	29,137	(7,944)
Other	**(3,513)**	42,067	52,397
Net cash used for investing activities	**(481,208)**	(568,546)	(832,702)
Net decrease in cash and cash equivalents	**(61,034)**	(111,957)	(37,960)
Cash and cash equivalents at beginning of year	**113,975**	225,932	263,892
Cash and cash equivalents at end of year	**$ 52,941**	$ 113,975	$ 225,932
Supplemental Cash Flows Information:			
Cash Paid During the Year-			
Interest (net of amounts capitalized)	**$ 704,067**	$ 730,277	$ 881,515
Income taxes	**$ 512,419**	$ 161,915	$ 389,180

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

CONSOLIDATED STATEMENTS OF TAXES

(In thousands)

For the Years Ended December 31,	2004	2003	2002
General Taxes:			
Kilowatt-hour excise*	**$ 236,398**	$ 228,216	$ 219,970
State gross receipts*	**139,616**	130,244	132,622
Real and personal property	**207,504**	183,694	218,683
Social security and unemployment	**75,898**	68,019	46,345
Other	**18,436**	28,292	32,709
Total general taxes	**$ 677,852**	$ 638,465	$ 650,329
Provision For Income Taxes:			
Currently payable-			
Federal	**$ 283,341**	$ 306,347	$ 326,417
State	**132,356**	118,155	104,867
Foreign	**—**	(1,165)	20,624
	415,697	423,337	451,908
Deferred, net-			
Federal	**245,967**	71,910	81,934
State	**38,968**	8,133	7,759
Foreign	**—**	—	13,600
	284,935	80,043	103,293
Investment tax credit amortization	**(26,672)**	(26,404)	(26,507)
Total provision for income taxes	**$ 673,960**	$ 476,976	$ 528,694
Reconciliation of Federal Income Tax Expense at Statutory Rate to Total Provision For Income Taxes:			
Book income before provision for income taxes	**$ 1,552,135**	$ 899,740	$ 1,081,498
Federal income tax expense at statutory rate	**$ 543,247**	$ 314,909	$ 378,524
Increases (reductions) in taxes resulting from-			
Amortization of investment tax credits	**(26,672)**	(26,404)	(26,507)
State income taxes, net of federal income tax benefit	**111,361**	82,088	73,207
Amortization of tax regulatory assets	**32,683**	31,909	29,296
Preferred stock dividends	**7,495**	7,202	13,634
Reserve for foreign operations	**—**	44,305	48,587
Other, net	**5,846**	22,967	11,953
Total provision for income taxes	**$ 673,960**	$ 476,976	$ 528,694
Accumulated Deferred Income Taxes at December 31:			
Property basis differences	**$ 2,451,213**	$ 2,293,209	$ 2,052,594
Regulatory transition charge	**785,312**	1,084,871	1,408,232
Customer receivables for future income taxes	**103,149**	139,335	144,073
Deferred sale and leaseback costs	**(92,417)**	(95,474)	(99,647)
Nonutility generation costs	**(174,174)**	(221,063)	(228,476)
Unamortized investment tax credits	**(61,267)**	(70,054)	(78,227)
Other comprehensive income	**(219,020)**	(243,743)	(398,883)
Lease market valuation liability	**(420,078)**	(455,074)	(490,698)
Retirement Benefits	**(185,573)**	(359,038)	(223,065)
Oyster Creek securitization (Note 10(C))	**184,245**	193,558	202,447
Loss carryforwards	**(463,106)**	(495,254)	(507,690)
Loss carryforward valuation reserve	**419,978**	470,813	482,061
Purchase accounting basis differences	**(2,657)**	(2,657)	(2,657)
Sale of generating assets	**(9,539)**	(11,785)	(11,786)
Provision for rate refund	**—**	—	(29,370)
All other	**8,031**	(49,569)	(149,226)
Net deferred income tax liability	**$ 2,324,097**	$ 2,178,075	$ 2,069,682

** Collected from customers through regulated rates and included in revenue on the Consolidated Statements of Income.*

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

1. Organization and Basis of Presentation

FirstEnergy's principal business is the holding, directly or indirectly, of all of the outstanding common stock of its eight principal electric utility operating subsidiaries: OE, CEI, TE, Penn, ATSI, JCP&L, Met-Ed and Penelec. Penn is a wholly owned subsidiary of OE. FirstEnergy's consolidated financial statements also include its other subsidiaries: FENOC, FES and its subsidiary FGCO, FESC, FirstCom, FSG, GPU Capital, GPU Power and MYR.

FirstEnergy and its subsidiaries follow GAAP and comply with the regulations, orders, policies and practices prescribed by the SEC, FERC and, as applicable, the PUCO, PPUC and NJBPU. The preparation of financial statements in conformity with GAAP requires management to make periodic estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses and the disclosure of contingent assets and liabilities. Actual results could differ from these estimates.

FirstEnergy consolidates all majority-owned subsidiaries over which the Company exercises control and, when applicable, entities for which the Company has a controlling financial interest. Intercompany transactions and balances are eliminated in consolidation. Investments in nonconsolidated affiliates (20-50 percent owned companies, joint ventures and partnerships) over which the Company has the ability to exercise significant influence, but not control, are accounted for on the equity basis.

Certain prior year amounts have been reclassified to conform to the current year presentation. Revenue amounts related to transmission activities previously recorded as wholesale electric sales revenues were reclassified as transmission revenues. Expenses (including transmission and congestion charges) were reclassified among purchased power, other operating costs and amortization of regulatory assets to conform to the current year presentation of generation commodity costs. FES' natural gas business has been classified as discontinued operations on the Consolidated Statements of Income (See Note 2(J)). As discussed in Note 14, segment reporting in 2003 and 2002 was reclassified to conform to the 2004 business segment organization and operations.

Unless otherwise indicated, defined terms used herein have the meanings set forth in the accompanying Glossary of Terms.

2. Summary of Significant Accounting Policies

(A) ACCOUNTING FOR THE EFFECTS OF REGULATION

FirstEnergy accounts for the effects of regulation through the application of SFAS 71 to its operating utilities when their rates:

- are established by a third-party regulator with the authority to set rates that bind customers;
- are cost-based; and
- can be charged to and collected from customers.

An enterprise meeting all of these criteria capitalizes costs that would otherwise be charged to expense if the rate actions of its regulator make it probable that those costs will be recovered in future revenue. SFAS 71 is applied only to the parts of the business that meet the above criteria. If a portion of the business applying SFAS 71 no longer meets those requirements, previously recorded regulatory assets are removed from the balance sheet in accordance with the guidance in SFAS 101.

In Ohio, New Jersey and Pennsylvania, laws applicable to electric industry restructuring contain similar provisions, that are reflected in the Companies' respective state regulatory plans. These provisions include:

- restructuring the electric generation business and allowing the Companies' customers to select a competitive electric generation supplier other than the Companies;
- establishing or defining the PLR obligations to customers in the Companies' service areas;
- providing the Companies with the opportunity to recover potentially stranded investment (or transition costs) not otherwise recoverable in a competitive generation market;
- itemizing (unbundling) the price of electricity into its component elements – including generation, transmission, distribution and stranded costs recovery charges;
- continuing regulation of the Companies' transmission and distribution systems; and
- requiring corporate separation of regulated and unregulated business activities.

Regulatory Assets

The EUOC recognize, as regulatory assets, costs which the FERC, PUCO, PPUC and NJBPU have authorized for recovery from customers in future periods or for which authorization is probable. Without the probability of such authorization, costs currently recorded as regulatory assets would have been charged to income as incurred. All regulatory assets are expected to be recovered from customers under the Companies' respective transition and regulatory plans. Based on those plans, the Companies continue to bill and collect cost-based rates for their transmission and distribution services, which remain regulated; accordingly, it is appropriate that the Companies continue the application of SFAS 71 to those operations. Regulatory assets that do not earn a current return totaled approximately $240 million as of December 31, 2004.

Net regulatory assets on the Consolidated Balance Sheets are comprised of the following:

	2004	2003
	(In millions)	
Regulatory transition costs	$4,889	$6,427
Customer shopping incentives	612	371
Customer receivables for future income taxes	246	340
Societal benefits charge	51	81
Loss on reacquired debt	89	75
Employee postretirement benefit costs	65	77
Nuclear decommissioning, decontamination and spent fuel disposal costs	(169)	(96)
Asset removal costs	(340)	(321)
Property losses and unrecovered plant costs	50	70
Other	39	53
Total	$5,532	$7,077

The Ohio Companies are deferring customer shopping incentives and interest costs as new regulatory assets in accordance with the transition and rate stabilization plans. These regulatory assets (OE – $228 million, CEI – $295 million, TE – $89 million, as of December 31, 2004) will be recovered through a surcharge rate equal to the RTC rate in effect when the transition costs have been fully recovered. Recovery of the new regulatory assets will begin at that time and amortization of the regulatory assets for each accounting period will be equal to the surcharge revenue recognized during that period. OE, TE and CEI expect to recover these deferred customer shopping incentives by August 31, 2008, September 30, 2008 and August 31, 2010, respectively.

Transition Cost Amortization

OE, CEI and TE amortize transition costs (see Regulatory Matters – Ohio) using the effective interest method. Under the Rate Stabilization Plan, total transition cost amortization is expected to approximate the following for 2005 through 2009.

	FirstEnergy	OE	CEI	TE
		(In millions)		
2005	$828	$467	$222	$139
2006	404	193	126	85
2007	327	93	139	95
2008	159	—	159	—
2009	54	—	54	—

The decrease in amortization beginning in 2006 results from the termination of generation-related transition cost recovery under the Ohio transition plan.

Regulatory transition costs as of December 31, 2004 for JCP&L, Met-Ed and Penelec are approximately $2.2 billion, $0.7 billion and $0.1 billion, respectively. Deferral of above-market costs from power supplied by NUGs to JCP&L are approximately $1.2 billion and are being recovered through BGS and MTC revenues. Met-Ed and Penelec have deferred above-market NUG costs totaling approximately $0.5 billion and $0.1 billion, respectively. These costs are being recovered through CTC revenues. The regulatory asset for above-market NUG costs and a corresponding liability are adjusted to fair value at the end of each quarter. Recovery of the remaining regulatory transition costs is expected to continue under the provisions of the various regulatory proceedings for New Jersey and Pennsylvania discussed in Note 9.

Accounting for Generation Operations

The application of SFAS 71 was discontinued prior to 2001 with respect to the Companies' generation operations. The SEC's interpretive guidance regarding asset impairment measurement provided that any supplemental regulated cash flows such as a CTC should be excluded from the cash flows of assets in a portion of the business not subject to regulatory accounting practices. If those assets are impaired, a regulatory asset should be established if the costs are recoverable through regulatory cash flows. Consistent with the SEC guidance and EITF 97-4, $1.8 billion of impaired plant investments ($1.2 billion, $227 million, $304 million and $53 million for OE, Penn, CEI and TE, respectively) were recognized as regulatory assets recoverable as transition costs through future regulatory cash flows. The following summarizes net assets included in property, plant and equipment relating to operations for which the application of SFAS 71 was discontinued, compared with the respective company's total assets as of December 31, 2004.

	SFAS 71 Discontinued Net Assets	Total Assets
	(In millions)	
OE	$1,059	$5,814
CEI	1,263	6,690
TE	652	2,834
Penn	263	921
JCP&L	39	7,291
Met-Ed	13	3,245

(B) CASH AND SHORT-TERM FINANCIAL INSTRUMENTS

All temporary cash investments purchased with an initial maturity of three months or less are reported as cash equivalents on the Consolidated Balance Sheets at cost, which approximates their fair market value.

(C) REVENUES AND RECEIVABLES

The Companies' principal business is providing electric service to customers in Ohio, Pennsylvania and New Jersey. The Companies' retail customers are metered on a cycle basis. Electric revenues are recorded based on energy delivered through the end of the calendar month. An estimate of unbilled revenues is calculated to recognize electric service provided between the last meter reading and the end of the month. This estimate includes many factors including estimated weather impacts, customer shopping activity, historical line loss factors and prices in effect for each class of customer. In each accounting period, the Companies accrue the estimated unbilled amount receivable as revenue and reverse the related prior period estimate.

Receivables from customers include sales to residential, commercial and industrial customers and sales to wholesale customers. There was no material concentration of receivables as of December 31, 2004 or 2003, with respect to any particular segment of FirstEnergy's customers. Total customer receivables were $979 million (billed – $672 million and unbilled – $307 million) and $1.0 billion (billed – $664 million and unbilled – $336 million) as of December 31, 2004 and 2003, respectively.

Other receivables include amounts due from customers for unregulated sales and CEI's retained interest in customer receivables sold to CFC (see Note 12).

(D) ACCOUNTING FOR CERTAIN WHOLESALE ENERGY TRANSACTIONS

FES engages in purchase and sale transactions in the PJM Market to support the supply of end-use customers, including its BGS obligation in New Jersey and PLR requirements in Pennsylvania. FES meets its supply commitments by transmitting energy into the PJM control area and through bilateral purchased power contracts with counterparties in PJM. FES schedules purchase and sale transactions for each hour in PJM on a day-ahead basis with system balancing occurring real-time. FES sells energy to the PJM Market at the location of its supply (transmitted and contracted energy) and purchases energy from the PJM Market at the location of its demand (end-use customer load).

FES accounts for energy transactions in the PJM Market in accordance with EITF 99-19, recognizing purchases and sales on a gross basis by recording each discrete transaction. This presentation may not be comparable to other energy companies that have dedicated generating capacity in ISOs or fail to meet the criteria for gross presentation in EITF 99-19.

FES' purchase and sale transactions in the PJM Market for the three years ended December 31, 2004 are summarized as follows:

	2004	2003	2002
		(In millions)	
Sales	$ 1,182	$ 665	$ 272
Purchases	1,107	826	376

(E) EARNINGS PER SHARE

Basic earnings per share are computed using the weighted average of actual common shares outstanding during the respective period as the denominator. The denominator for diluted earnings per share reflects the weighted average of common shares outstanding plus the potential additional common shares that could result if dilutive securities and other agreements to issue common stock were exercised. In 2004, 2003 and 2002, stock-based awards to purchase shares of common stock totaling 0.1 million, 3.3 million and 3.4 million, respectively, were excluded from the calculation of diluted earnings per share of common stock because their exercise prices were greater than the average market price of common shares during the period. The following table reconciles the denominators for basic and diluted earnings per share from Income Before Discontinued Operations and Cumulative Effect of Accounting Change:

Reconciliation of Basic and Diluted Earnings per Share	2004	2003	2002
		(In thousands)	
Income Before Discontinued Operations and Cumulative Effect of Accounting Change	$873,779	$424,249	$618,385
Average Shares of Common Stock Outstanding:			
Denominator for basic earnings per share (weighted average shares outstanding)	327,387	303,582	293,194
Assumed exercise of dilutive stock options and awards	1,595	1,390	1,227
Denominator for diluted earnings per share	328,982	304,972	294,421
Income Before Discontinued Operations and Cumulative Effect of Accounting Change per common share:			
Basic	$2.67	$1.40	$2.11
Diluted	$2.66	$1.40	$2.10

(F) PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment reflects original cost (except for nuclear generating assets which were adjusted to fair value), including payroll and related costs such as taxes, employee benefits, administrative and general costs, and interest costs incurred to place the assets in service. The costs of normal maintenance, repairs and minor replacements are expensed as incurred. FirstEnergy's accounting policy for planned major maintenance projects is to recognize liabilities as they are incurred.

The Companies provide for depreciation on a straight-line basis at various rates over the estimated lives of property included in plant in service. The respective annual composite rates for the Companies' electric plant in 2004, 2003 and 2002 are shown in the following table:

Annual Composite Depreciation Rate	2004	2003	2002
OE	2.3%	2.2%	2.4%
CEI	2.8	2.8	3.6
TE	2.8	2.8	3.8
Penn	2.2	2.2	2.3
JCP&L	2.1	2.8	3.5
Met-Ed	2.4	2.6	3.0
Penelec	2.5	2.7	3.0

Jointly-Owned Generating Stations

JCP&L holds a 50 percent ownership interest in Yards Creek Pumped Storage Facility – its net book value was approximately $19.2 million as of December 31, 2004. All other generating units are owned and/or leased by the Companies individually or together as tenants in common.

Asset Retirement Obligations

FirstEnergy recognizes a liability for retirement obligations associated with tangible assets in accordance with SFAS 143. This standard requires recognition of the fair value of a liability for an ARO in the period in which it is incurred. The associated asset retirement costs are capitalized as part of the carrying value of the long-lived asset and depreciated over time, as described further in Note 11, "Asset Retirement Obligations".

Nuclear Fuel

Property, plant and equipment includes nuclear fuel recorded at original cost, which includes material, enrichment, fabrication and interest costs incurred prior to reactor load. The Companies amortize the cost of nuclear fuel based on the units of production method.

(G) STOCK-BASED COMPENSATION

FirstEnergy applies the recognition and measurement principles of APB 25 and related Interpretations in accounting for its stock-based compensation plans (see Note 4). No material stock-based employee compensation expense is reflected in net income for options as all options granted under those plans had an exercise price equal to the market value of the underlying common stock on the grant date, resulting in substantially no intrinsic value. FirstEnergy will apply the recognition and measurement principles of SFAS 123R effective July 1, 2005 (see Note 15).

(H) ASSET IMPAIRMENTS

Long-Lived Assets

FirstEnergy evaluates the carrying value of its long-lived assets when events or circumstances indicate that the carrying amount may not be recoverable. In accordance with SFAS 144, the carrying amount of a long-lived asset is not recoverable if it exceeds the sum of the undiscounted cash flows expected to result from the use and eventual disposition of the asset. If an impairment exists, a loss is recognized for the amount by which the carrying value of the long-lived asset exceeds its estimated fair value. Fair value is estimated by using available market valuations or the long-lived asset's expected future net discounted cash flows. The calculation of expected cash flows is based on estimates and assumptions about future events.

Goodwill

In a business combination, the excess of the purchase price over the estimated fair values of assets acquired and liabilities assumed is recognized as goodwill. Based on the guidance provided by SFAS 142, FirstEnergy evaluates its goodwill for impairment at least annually and makes such evaluations more frequently if indicators of impairment arise. In accordance with the accounting standard, if the fair value of a reporting unit is less than its carrying value (including goodwill), the goodwill is tested for impairment. If an impairment is indicated, FirstEnergy recognizes a loss – calculated as the difference between the implied fair value of a reporting unit's goodwill and the carrying value of the goodwill.

FirstEnergy's 2003 annual review resulted in a non-cash goodwill impairment charge of $122 million in the third quarter of 2003, reducing the carrying value of FSG. Of this amount, $117 million was reported as an operating expense and $5 million was included in the results from discontinued operations. The impairment charge reflected the slow down in the development of competitive retail markets and depressed economic conditions that affected the value of FSG. The fair value of FSG was estimated using primarily its expected discounted future cash flows.

FirstEnergy's 2004 annual review was completed in the third quarter of 2004 with no impairment indicated. In December 2004, the FSG subsidiaries qualified as held for sale in accordance with SFAS 144. SFAS 142 requires the goodwill of a reporting unit to be tested for impairment if there is a more-likely-than-not expectation that the reporting unit or a significant asset group within the reporting unit will be sold. As required by SFAS 142, the goodwill of FSG was tested for impairment, resulting in a non-cash charge of $36 million in the fourth quarter of 2004. FSG's fair value was estimated using current market valuations.

The forecasts used in FirstEnergy's evaluations of goodwill reflect operations consistent with its general business assumptions. Unanticipated changes in those assumptions could have a significant effect on FirstEnergy's future evaluations of goodwill. FirstEnergy's goodwill primarily relates to its regulated services segment. In the year ended December 31, 2004, FirstEnergy adjusted goodwill related to the former GPU companies for interest received on a pre-merger income tax refund and for the reversal of tax valuation allowances related to income tax benefits realized attributable to prior period capital loss carryforwards that were used to offset capital gains generated in 2004. The impairment analysis includes a significant source of cash representing the Companies' recovery of transition costs as described in Note 9. FirstEnergy estimates that completion of transition cost recovery will not result in an impairment of goodwill relating to its regulated business segment.

A summary of the changes in FirstEnergy's goodwill for the years ended December 31, 2004 and 2003 is shown below by segment (See Note 14 – Segment Information):

	Regulated Services	Competitive Electric Energy Services	Facilities Services	Other	Consolidated
			(In millions)		
Balance as of Jan. 1, 2003	$5,993	$24	$196	$65	$6,278
Impairment charges			(122)		(122)
FSG divestitures			(41)		(41)
Other			3	10	13
Balance as of Dec. 31, 2003	5,993	24	36	75	6,128
Impairment charges			(36)		(36)
Adjustments related to GPU acquisition	(42)				(42)
Balance as of Dec. 31, 2004	$5,951	$24	$ –	$75	$6,050

Investments

The Companies periodically evaluate for impairment investments that include available-for-sale securities held by their nuclear decommissioning trusts. In accordance with SFAS 115, securities classified as available-for-sale are evaluated to determine whether a decline in fair value below the cost basis is other than temporary. If the decline in fair value is determined to be other than temporary, the cost basis of the security is written down to fair value. FirstEnergy considers, among other factors, the length of time and the extent to which the security's fair value has been less than cost and the near-term financial prospects of the security issuer when evaluating investments for impairment. The fair value and unrealized gains and losses of the Companies' investments are disclosed in Note 5.

(I) COMPREHENSIVE INCOME

Comprehensive income includes net income as reported on the Consolidated Statements of Income and all other changes in common stockholders' equity except those resulting from transactions with common stockholders. As of December 31, 2004, AOCL consisted of a minimum liability for unfunded retirement benefits of $312 million, unrealized gains on investments in securities available for sale of $91 million, and unrealized losses on derivative instrument hedges of $92 million. As of December 31, 2003, AOCL consisted of a minimum liability for unfunded retirement benefits of $306 million, unrealized gains on investments in securities available for sale of $64 million, and unrealized losses on derivative instrument hedges of $111 million. Other comprehensive income of $8 million was reclassified to net income in 2004, including an $8 million loss on derivative instrument hedges ($5 million net of tax) and a $22 million gain on available-for-sale securities ($13 million net of tax). Other comprehensive income (loss) reclassified to net income in 2003 and 2002 totaled $29 million and $(10) million, respectively. These amounts were net of income taxes in 2003 and 2002 of $20 million and $(7) million, respectively.

(J) ASSETS HELD FOR SALE AND DISCONTINUED OPERATIONS

In December 2004, the FSG subsidiaries qualified as held for sale in accordance with SFAS 144. Management anticipates that the transfer of FSG assets, with a carrying value of $57 million as of December 31, 2004, will qualify for recognition as completed sales within one year. As required by SFAS 142, the goodwill of FSG was tested for impairment, resulting in a non-cash charge of $36 million in the fourth quarter of 2004 (See Note 2(H)). As of December 31, 2004, the FSG subsidiaries classified as held for sale did not meet the criteria for discontinued operations. The carrying amounts of FSG's assets and liabilities held for sale are not material to and have not been classified as assets held for sale on FirstEnergy's Consolidated Balance Sheets. See Note 14 for FSG's segment financial information.

FES operates a natural gas business with commercial and industrial customers in Ohio, Pennsylvania and West Virginia. Sales requirements are sourced through a combination of short-term and long-term supply agreements. In December 2004, FES' natural gas business qualified as held for sale in accordance with SFAS 144. Management expects to complete the sale within one year. As required by SFAS 142, goodwill associated with FES' natural gas business was tested for impairment as of December 31, 2004 with no impairment indicated. Financial results are included in discontinued operations on the Consolidated Statements of Income and classified as "Other" in the segment financial information (See Note 14). FES' natural gas purchases and sales for the three years ended December 31, 2004 are summarized as follows:

	2004	2003	2002
		(In millions)	
Natural gas sales	$ 496	$ 603	$ 594
Natural gas purchases	480	583	544

In December 2003, EGSA, GPU Power's Bolivia subsidiary, was sold to Bolivia Integrated Energy Limited. FirstEnergy included in discontinued operations a $33 million loss on the sale of EGSA in the fourth quarter of 2003 (no income tax benefit was realized) and an operating loss for the year of $2 million. Discontinued operations in 2002 include EGSA's operating income of $10 million.

In April 2003, FirstEnergy divested its ownership in Emdersa through the abandonment of its shares in Emdersa's parent company, GPU Argentina Holdings, Inc. The abandonment was accomplished by relinquishing FirstEnergy's shares to the independent Board of Directors of GPU Argentina Holdings, relieving FirstEnergy of all rights and obligations relative to this business. FirstEnergy included in discontinued operations Emdersa's operating income of $11 million and a $67 million charge for the abandonment in the second quarter of 2003 (no income tax benefit was recognized). An after-tax loss of $87 million (including $109 million in currency transaction losses arising principally from U.S. dollar denominated debt) was included in discontinued operations in 2002.

The FSG subsidiaries, Colonial Mechanical and Webb Technologies, were sold in January 2003 and Ancoma, Inc. was sold in December 2003. The MARBEL subsidiary, NEO was sold in June 2003. The 2003 and 2002 operating results for these divested businesses included in discontinued operations ("Other" in the table below) for the years ended December 2003 and 2002 totaled $(6) million and $5 million, respectively.

Revenues associated with discontinued operations were $496 million, $655 million and $878 million for 2004, 2003 and 2002, respectively. The following table summarizes the net income (loss) included in "Discontinued Operations" on the Consolidated Statements of Income for the three years ended December 31, 2004:

	2004	2003	2002
		(In millions)	
FES' natural gas business	$ 4	$ (2)	$ 15
EGSA	—	(35)	5
Emdersa	—	(60)	(87)
Other	—	(6)	2
Discontinued operations income (loss)	$4	$(103)	$(65)

(K) CUMULATIVE EFFECT OF ACCOUNTING CHANGE

As a result of adopting SFAS 143 in January 2003, FirstEnergy recorded a $175 million increase to income, $102 million net of tax, or $0.33 per share of common stock (basic and diluted) in the year ended December 31, 2003. Upon adoption of the accounting standard, FirstEnergy reversed accrued nuclear plant decommissioning costs of $1.24 billion and recorded an ARO of $1.11 billion, including accumulated accretion of $507 million for the period from the date the liability was incurred to the date of adoption. FirstEnergy also recorded asset retirement costs of $602 million as part of the carrying amount of the related long-lived asset and accumulated depreciation of $415 million. FirstEnergy recognized a regulatory liability of $185 million for the transition amounts subject to refund through rates related to the ARO for nuclear decommissioning. The cumulative effect adjustment also included the reversal of $60 million of accumulated estimated removal costs for non-regulated generation assets.

(L) INCOME TAXES

Details of the total provision for income taxes are shown on the Consolidated Statements of Taxes. FirstEnergy records income taxes in accordance with the liability method of accounting. Deferred income taxes reflect the net tax effect of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts recognized for tax purposes. Investment tax credits, which were deferred when utilized, are being amortized over the recovery period of the related property. Deferred income tax liabilities related to tax and accounting basis differences and tax credit carryforward items are recognized at the statutory income tax rates in effect when the liabilities are expected to be paid. Deferred tax assets are recognized based on income tax rates expected to be in effect when they are settled.

FirstEnergy has capital loss carryforwards of approximately $1.1 billion, most of which expire in 2007. The deferred tax assets associated with these capital loss carryforwards ($364 million) are fully offset by a valuation allowance as of December 31, 2004, since management is unable to predict whether sufficient capital gains will be generated to utilize all of these capital loss carryforwards. Any ultimate utilization of capital loss carryforwards for which valuation allowances were established through purchase accounting would adjust goodwill.

The Company has also recorded valuation allowances of $51 million for deferred tax assets associated with impairment losses related to certain domestic assets and the divestiture of international assets acquired through the merger with GPU (see Note 8).

FirstEnergy has net operating loss carryforwards for state and local income tax purposes of approximately $884 million. A valuation allowance of $5 million has been recorded against the associated deferred tax assets of $48 million. These losses expire as follows:

Expiration Period	**Amount**
	(In millions)
2005-2009	$260
2010-2014	46
2015-2019	217
2020-2023	361
	$884

3. Pension and Other Postretirement Benefit Plans

FirstEnergy provides noncontributory defined benefit pension plans that cover substantially all of its employees. The trusteed plans provide defined benefits based on years of service and compensation levels. The Company's funding policy is based on actuarial computations using the projected unit credit method. In the third quarter of 2004, FirstEnergy made a $500 million voluntary contribution to its pension plan. Prior to this contribution, projections indicated that cash contributions of approximately $600 million would have been required during the 2006 to 2007 time period under minimum funding requirements established by the IRS. The election to pre-fund the plan is expected to eliminate that funding requirement. Since the contribution is deductible for tax purposes, the after-tax cash impact of the voluntary contribution was approximately $300 million.

FirstEnergy provides a minimum amount of noncontributory life insurance to retired employees in addition to optional contributory insurance. Health care benefits, which include certain employee contributions, deductibles and copayments, are also available to retired employees, their dependents and, under certain circumstances, their survivors. The Company recognizes the expected cost of providing other postretirement benefits to employees and their beneficiaries and covered dependents from the time employees are hired until they become eligible to receive those benefits.

Pension and OPEB costs are affected by employee demographics (including age, compensation levels, and employment periods), the level of contributions made to the plans and earnings on plan assets. Such factors may be further affected by business combinations which impact employee demographics, plan experience and other factors. Pension and OPEB costs may also be affected by changes in key assumptions, including anticipated rates of return on plan assets, the discount rates and health care trend rates used in determining the projected benefit obligations and pension and OPEB costs. FirstEnergy uses a December 31 measurement date for the majority of its plans.

Obligations and Funded Status As of December 31

	Pension Benefits		**Other Benefits**	
	2004	**2003**	**2004**	**2003**
	(In millions)			
Change in benefit obligation				
Benefit obligation as of January 1	$4,162	$3,866	$ 2,368	$ 2,077
Service cost	77	66	36	43
Interest cost	252	253	112	136
Plan participants' contributions	—	—	14	6
Plan amendments	—	—	(281)	(123)
Actuarial (gain) loss	134	222	(211)	323
Benefits paid	(261)	(245)	(108)	(94)
Benefit obligation as of December 31	$4,364	$4,162	$ 1,930	$ 2,368
Change in fair value of plan assets				
Fair value of plan assets as of January 1	$3,315	$2,889	$ 537	$ 473
Actual return on plan assets	415	671	57	88
Company contribution	500	—	64	68
Plan participants' contribution	—	—	14	2
Benefits paid	(261)	(245)	(108)	(94)
Fair value of plan assets as of December 31	$3,969	$3,315	$ 564	$ 537
Funded status	$ (395)	$ (847)	$ (1,366)	$(1,831)
Unrecognized net actuarial loss	885	919	730	994
Unrecognized prior service cost (benefit)	63	72	(378)	(221)
Unrecognized net transition obligation	—	—	—	83
Net asset (liability) recognized	$ 553	$ 144	$ (1,014)	$ (975)
Amounts Recognized in the Consolidated Balance Sheets As of December 31				
Accrued benefit cost	$ (14)	$ (438)	$(1,014)	$ (975)
Intangible assets	63	72	—	—
Accumulated other comprehensive loss	504	510	—	—
Net amount recognized	$553	$ 144	$(1,014)	$ (975)
Increase (decrease) in minimum liability included in other comprehensive income (net of tax)	$ (4)	$ (145)	—	—
Assumptions Used to Determine Benefit Obligations As of December 31				
Discount rate	6.00%	6.25%	6.00%	6.25%
Rate of compensation increase	3.50%	3.50%		
Allocation of Plan Assets As of December 31				
Asset Category				
Equity securities	68%	70%	74%	71%
Debt securities	29	27	25	22
Real estate	2	2	—	—
Cash	1	1	1	7
Total	100%	100%	100%	100%

Information for Pension Plans With an Accumulated Benefit Obligation in Excess of Plan Assets	**2004**	**2003**
	(In millions)	
Projected benefit obligation	$4,364	$4,162
Accumulated benefit obligation	3,983	3,753
Fair value of plan assets	3,969	3,315

Components of Net Periodic Benefit Costs

	Pension Benefits			Other Benefits		
	2004	2003	2002	2004	2003	2002
	(In millions)					
Service cost	$ 77	$ 66	$ 59	$ 36	$ 43	$ 29
Interest cost	252	253	249	112	137	114
Expected return on plan assets	(286)	(248)	(346)	(44)	(43)	(52)
Amortization of prior service cost	9	9	9	(40)	(9)	3
Amortization of transition obligation (asset)	—	—	—	—	9	9
Recognized net actuarial loss	39	62	—	39	40	11
Net periodic cost (income)	$ 91	$142	$ (29)	$103	$177	$114

Weighted-Average Assumptions Used to Determine Net Periodic Benefit Cost for Years Ended December 31

	Pension Benefits			Other Benefits		
	2004	2003	2002	2004	2003	2002
Discount rate	6.25%	6.75%	7.25%	6.25%	6.75%	7.25%
Expected long-term return on plan assets	9.00%	9.00%	10.25%	9.00%	9.00%	10.25%
Rate of compensation increase	3.50%	3.50%	4.00%			

In selecting an assumed discount rate, FirstEnergy considers currently available rates of return on high-quality fixed income investments expected to be available during the period to maturity of the pension and other postretirement benefit obligations. The assumed rate of return on pension plan assets considers historical market returns and economic forecasts for the types of investments held by the Company's pension trusts. The long-term rate of return is developed considering the portfolio's asset allocation strategy.

FirstEnergy employs a total return investment approach whereby a mix of equities and fixed income investments are used to maximize the long-term return of plan assets for a prudent level of risk. Risk tolerance is established through careful consideration of plan liabilities, plan funded status, and corporate financial condition. The investment portfolio contains a diversified blend of equity and fixed-income investments. Furthermore, equity investments are diversified across U.S. and non-U.S. stocks, as well as growth, value, and small and large capitalizations. Other assets such as real estate are used to enhance long-term returns while improving portfolio diversification. Derivatives may be used to gain market exposure in an efficient and timely manner; however, derivatives are not used to leverage the portfolio beyond the market value of the underlying investments. Investment risk is measured and monitored on a continuing basis through periodic investment portfolio reviews, annual liability measurements, and periodic asset/liability studies.

Assumed Health Care Cost Trend Rates As of December 31	2004	2003
Health care cost trend rate assumed for next year (pre/post-Medicare)	9%-11%	10%-12%
Rate to which the cost trend rate is assumed to decline (the ultimate trend rate)	5%	5%
Year that the rate reaches the ultimate trend rate (pre/post-Medicare)	2009-2011	2009-2011

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:

	1-Percentage Point Increase	1-Percentage Point Decrease
	(In millions)	
Effect on total of service and interest cost	$ 19	$ (16)
Effect on postretirement benefit obligation	$205	$(179)

Pursuant to FSP 106-1 issued January 12, 2004, FirstEnergy began accounting for the effects of the Medicare Act effective January 1, 2004 because of a plan amendment during the quarter, which required remeasurement of the plan's obligations. The plan amendment, which increases cost sharing by employees and retirees effective January 1, 2005, reduced postretirement benefit costs by $51 million during 2004.

Consistent with the guidance in FSP 106-2 issued on May 19, 2004, FirstEnergy recognized a reduction of $318 million in the accumulated postretirement benefit obligation as a result of the federal subsidy provided under the Medicare Act related to benefits for past service. This reduction was accounted for as an actuarial gain in 2004 pursuant to FSP 106-2. The subsidy reduced net periodic postretirement benefit costs by $48 million during 2004.

As a result of its voluntary contribution and the increased market value of pension plan assets, FirstEnergy reduced its accrued benefit cost as of December 31, 2004 by $424 million. As prescribed by SFAS 87, FirstEnergy reduced its additional minimum liability by $15 million, recording a decrease in an intangible asset of $9 million and crediting OCI by $6 million. The balance in AOCL of $296 million (net of $208 million in deferred taxes) will reverse in future periods to the extent the fair value of trust assets exceeds the accumulated benefit obligation.

Taking into account estimated employee future service, FirstEnergy expects to make the following benefit payments from plan assets:

	Pension Benefits	Other Benefits
	(In millions)	
2005	$ 228	$111
2006	228	106
2007	236	109
2008	247	112
2009	264	115
Years 2010 – 2014	1,531	627

4. Stock-Based Compensation Plans

FirstEnergy has four stock-based compensation programs: Long-term Incentive Program (LTIP); Executive Deferred Compensation Plan (EDCP); Employee Stock Ownership Plan (ESOP); and the Deferred Compensation Plan for Outside Directors (DCPD). FirstEnergy has also assumed responsibility for several stock-based plans through acquisitions. In 2001, FirstEnergy assumed responsibility for two stock-based plans as a result of its acquisition of GPU. No further stock-based compensation can be awarded under GPU's Stock Option and Restricted Stock Plan for MYR Group Inc. Employees (MYR Plan) or 1990 Stock Plan for Employees of GPU, Inc. and Subsidiaries (GPU Plan). All options and restricted stock under both plans have been converted into FirstEnergy options and restricted stock. Options under the GPU Plan became fully vested on November 7, 2001, and will expire on or before June 1, 2010. Under the MYR Plan, all options and restricted stock maintained their original vesting periods, which range from one to four years, and will expire on or before December 17, 2006. The Centerior Equity Plan (CE Plan) is an additional stock-based plan administered by FirstEnergy for which it assumed responsibility as a result of the acquisition of Centerior Energy Corporation in 1997. All options are fully vested under the CE Plan, and no further awards are permitted. Outstanding options will expire on or before February 25, 2007.

(A) LTIP

FirstEnergy's LTIP includes three stock-based compensation programs – restricted stock, stock options, and performance shares.

Under FirstEnergy's LTIP, total awards cannot exceed 22.5 million shares of common stock or their equivalent. Only stock options and restricted stock have currently been designated to pay out in common stock, with vesting periods ranging from two months to seven years. Performance share awards are currently designated to be paid in cash rather than common stock and therefore do not count against the limit on stock-based awards. As of December 31, 2004, 4.5 million shares were available for future awards.

Restricted Stock

Eligible employees receive awards of FirstEnergy common stock subject to restrictions. Those restrictions lapse over a defined period of time or based on performance. Dividends are received on the restricted stock and are reinvested in additional shares. Restricted common stock grants under the FE Plan were as follows:

	2004	2003*	2002
Restricted common shares granted	62,370		36,922
Weighted average market price	$40.69		$36.04
Weighted average vesting period (years)	2.7		3.2
Dividends restricted	Yes		Yes

** No restricted stock was granted.*

Compensation expense recognized for restricted stock during 2004, 2003 and 2002 totaled $1,982,000, $1,747,000 and $2,259,000, respectively.

Stock Options

Stock option grants are provided to eligible employees allowing them to purchase a specified number of common shares at a fixed grant price over a defined period of time. Stock option activities under the FE Programs for the past three years were as follows:

Stock Option Activities	Number of Options	Weighted Average Exercise Price
Balance, January 1, 2002	8,447,688	$26.04
(1,828,341 options exercisable)		24.83
Options granted	3,399,579	34.48
Options exercised	1,018,852	23.56
Options forfeited	392,929	28.19
Balance, December 31, 2002	10,435,486	28.95
(1,400,206 options exercisable)		26.07
Options granted	3,981,100	29.71
Options exercised	455,986	25.94
Options forfeited	311,731	29.09
Balance, December 31, 2003	13,648,869	29.27
(1,919,662 options exercisable)		29.67
Options granted	3,373,459	38.77
Options exercised	3,622,148	26.52
Options forfeited	167,425	32.58
Balance, December 31, 2004	13,232,755	32.40
(3,175,023 options exercisable)		29.07

Options outstanding by plan and range of exercise price as of December 31, 2004 were as follows:

		Options Outstanding			Options Exercisable	
FE Program	Range of Exercise Prices	Shares	Weighted Avg. Exercise Price	Remaining Contractual Life	Shares	Weighted Avg. Exercise Price
FE plan	$19.31-$29.87	6,972,940	$28.82	7.0	1,903,790	$26.72
	$30.17-$39.46	5,907,710	$36.89	8.3	919,128	$34.37
Plans acquired Through merger:						
GPU plan	$23.75-$35.92	341,455	$28.35	4.4	341,455	$28.35
MYR plan	$ 9.35-$14.23	8,550	$12.70	4.5	8,550	$12.70
CE plan	$25.14-$25.15	2,100	$25.14	2.2	2,100	$25.14
Total		13,232,755	$32.40	7.5	3,175,023	$29.07

The weighted average fair value of options granted in 2004, 2003 and 2002, respectively, are estimated below using the Black-Scholes option-pricing model and the following assumptions:

	2004	2003	2002
Fair value per option	$6.72	$5.09	$6.45
Weighted average valuation assumptions:			
Expected option term (years)	7.6	7.9	8.1
Expected volatility	26.25%	26.91%	23.31%
Expected dividend yield	3.88%	5.09%	4.36%
Risk-free interest rate	1.99%	3.67%	4.60%

Compensation expense for FirstEnergy stock options is based on intrinsic value, which equals any positive difference between FirstEnergy's common stock price on the option's grant date and the option's exercise price. The exercise prices of all stock options granted in 2004, 2003 and 2002 equaled the market price of FirstEnergy's common stock on the options' grant dates. If fair value accounting were applied to FirstEnergy's stock options, net income and earnings per share would be reduced as summarized below.

	2004	2003	2002
	(In thousands, except per share amounts)		
Net Income, as reported	$878,175	$422,764	$552,804
Add back compensation expense reported in net income, net of tax (based on APB 25)*	21,177	23,625	22,981
Deduct compensation expense based upon estimated fair value, net of tax*	(35,660)	(35,816)	(31,640)
Proforma net income	$863,692	$410,573	$544,145
Earnings Per Share of Common Stock –			
Basic			
As Reported	$2.68	$1.39	$1.89
Proforma	$2.64	$1.35	$1.86
Diluted			
As Reported	$2.67	$1.39	$1.88
Proforma	$2.63	$1.35	$1.85

* *Includes restricted stock, stock options, performance shares, ESOP, EDCP and DCPD.*

FirstEnergy anticipates reducing its use of stock options beginning in 2005 and increasing its use of performance-based, restricted stock units. Therefore, the pro forma effects of applying SFAS 123 may not be representative of its future effect. FirstEnergy has not and does not expect to accelerate out-of-the-money options in anticipation of implementing revisions to SFAS 123 on July 1, 2005 (see Note 15 - "New Accounting Standards and Interpretations").

Performance Shares

Performance shares are share equivalents and do not have voting rights. The shares track the performance of FirstEnergy's common stock over a three-year vesting period. During that time dividend equivalents are converted into additional shares. The final account value may be adjusted based on the ranking of FirstEnergy stock to a composite of peer companies. Compensation expense recognized for performance shares during 2004, 2003 and 2002 totaled $4,924,000, $7,131,000 and $6,757,000, respectively.

(B) ESOP

An ESOP Trust funds most of the matching contribution for FirstEnergy's 401(k) savings plan. All full-time employees eligible for participation in the 401(k) savings plan are covered by the ESOP. The ESOP borrowed $200 million from OE and acquired 10,654,114 shares of OE's common stock (subsequently converted to FirstEnergy common stock) through market purchases. Dividends on ESOP shares are used to service the debt. Shares are released from the ESOP on a pro rata basis as debt service payments are made. In 2004, 2003 and 2002, 864,151 shares, 1,069,318 shares and 1,151,106 shares, respectively, were allocated to employees with the corresponding expense recognized based on the shares allocated method. The fair value of 2,032,800 shares unallocated, as of December 31, 2004, was approximately $80 million. Total ESOP-related compensation expense was calculated as follows:

	2004	2003	2002
		(In millions)	
Base compensation	$32	$35	$34
Dividends on common stock held by the ESOP and used to service debt	(9)	(9)	(8)
Net expense	$23	$26	$26

(C) EDCP

Under the EDCP, covered employees can direct a portion of their compensation, including annual incentive awards and/or long-term incentive awards, into an unfunded FirstEnergy stock account to receive vested stock units. An additional 20 percent premium is received in the form of stock units based on the amount allocated to the FirstEnergy stock account. Dividends are calculated quarterly on stock units outstanding and are paid in the form of additional stock units. Upon withdrawal, stock units are converted to FirstEnergy shares. Payout typically occurs three years from the date of deferral; however, an election can be made in the year prior to payout to further defer shares into a retirement stock account that will pay out in cash upon retirement. Of the 1.3 million EDCP stock units authorized, 776,072 stock units were available for future award as of December 31, 2004. Compensation expense recognized on EDCP stock units in 2004, 2003 and 2002 totaled $2,311,000, $2,312,000 and $206,000, respectively.

(D) DCPD

Under the DCPD, directors can elect to allocate all or a portion of their cash retainers, meeting fees and chair fees to a deferred stock or deferred cash accounts. If the funds are deferred into the stock account, a 20 percent match is added to the funds allocated. The 20 percent match and any appreciation on it are forfeited if the director leaves the Board within three years from the date of deferral for any reason other than retirement, disability, death, upon a change in control, or when a director is ineligible to stand for re-election. Compensation expense is recognized for the 20 percent match over the three-year investing period. Directors may also elect to defer their equity retainers into the deferred stock account, however, they do not receive a 20 percent match for this deferral. DCPD expenses recognized in 2004, 2003, and 2002 were $3,556,000, $2,233,000 and $2,728,000, respectively.

5. Fair Value of Financial Instruments

Long-term Debt and Other Long-term Obligations

All borrowings with initial maturities of less than one year are defined as financial instruments under GAAP and are reported on the Consolidated Balance Sheets at cost, which approximates their fair market value. The following table provides the approximate fair value and related carrying amounts of long-term debt and other long-term obligations as of December 31:

	2004		2003	
	Carrying Value	Fair Value	Carrying Value	Fair Value
		(In millions)		
Long-term debt	$10,787	$11,341	$11,177	$11,648
Subordinated debentures to affiliated trusts	103	112	294	322
Preferred stock subject to mandatory redemption	17	16	19	19
	$10,907	$11,469	$11,490	$11,989

The fair values of long-term debt and other long-term obligations reflect the present value of the cash outflows relating to those securities based on the current call price, the yield to maturity or the yield to call, as deemed appropriate at the end of each respective year. The yields assumed were based on securities with similar characteristics offered by corporations with credit ratings similar to the Companies' ratings.

Investments

The carrying amounts of cash and cash equivalents approximate fair value due to the short-term nature of these investments. The following table provides the approximate fair value and related carrying amounts of investments other than cash and cash equivalents as of December 31:

	2004		2003	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	(In millions)			
Debt securities: [1]				
-Government obligations	$ 797	$ 797	$ 707	$ 707
-Corporate debt securities [2]	1,205	1,362	1,492	1,601
-Mortgage-backed securities	2	2	—	—
	2,004	2,161	2,199	2,308
Equity securities [1]	1,033	1,033	1,068	1,068
	$3,037	$3,194	$3,267	$3,376

[1] *Includes nuclear decommissioning, nuclear fuel disposal and NUG trust investments.*
[2] *Includes investments in lease obligation bonds (See Note 6).*

The fair value of investments other than cash and cash equivalents represent cost (which approximates fair value) or the present value of the cash inflows based on the yield to maturity. The yields assumed were based on financial instruments with similar characteristics and terms.

Investments other than cash and cash equivalents include held-to-maturity securities and available-for-sale securities. Decommissioning trust investments are classified as available-for-sale. The Companies have no securities held for trading purposes. The following table summarizes the amortized cost basis, unrealized gains and losses and fair values for decommissioning trust investments as of December 31:

	2004				2003			
	Cost Basis	Un-realized Gains	Un-realized Losses	Fair Value	Cost Basis	Un-realized Gains	Un-realized Losses	Fair Value
	(In millions)							
Debt securities	$ 616	$ 19	$ 3	$ 632	$ 548	$ 26	$ 1	$ 573
Equity securities	763	207	19	951	593	217	31	779
	$1,379	$226	$22	$1,583	$1,141	$243	$32	$1,352

Proceeds from the sale of decommissioning trust investments, realized gains and losses on those sales, and interest and dividend income for the three years ended December 31, 2004 were as follows:

	2004	2003	2002
	(In millions)		
Proceeds from sales	$1,234	$ 758	$599
Realized gains	144	38	32
Realized losses	43	32	47
Interest and dividend income	45	37	33

The following table provides the fair value of and unrealized losses on nuclear decommissioning trust investments that are deemed to be temporarily impaired as of December 31, 2004:

	Less Than 12 Months		12 Months or More		Total	
	Fair Value	Unrealized Losses	Fair Value	Unrealized Losses	Fair Value	Unrealized Losses
	(In millions)					
Debt securities	$175	$ 3	$20	$—	$195	$ 3
Equity securities	129	12	39	7	168	19
	$304	$15	$59	$7	$363	$22

The Companies periodically evaluate the securities held by their nuclear decommissioning trusts for other-than-temporary impairment. FirstEnergy considers the length of time and the extent to which the security's fair value has been less than its cost basis and other factors to determine whether impairment is other than temporary. Unrealized gains and losses applicable to the decommissioning trusts of FirstEnergy's Ohio Companies are recognized in OCI in accordance with SFAS 115, as fluctuations in fair value will eventually affect earnings. The decommissioning trusts of FirstEnergy's Pennsylvania and New Jersey Companies are subject to regulatory accounting in accordance with SFAS 71. Net unrealized gains and losses are recorded as regulatory liabilities or assets since the difference between investments held in trust and the decommissioning liabilities are recovered from, or refunded to, customers.

The investment policy for the nuclear decommissioning trust funds restricts or limits the ability to hold certain types of assets including private or direct placements, warrants, securities of FirstEnergy, investments in companies owning nuclear power plants, financial derivatives, preferred stocks, securities convertible into common stock and securities of the trust fund's custodian or managers and their parents or subsidiaries.

Derivatives

FirstEnergy is exposed to financial risks resulting from the fluctuation of interest rates and commodity prices, including prices for electricity, natural gas and coal. To manage the volatility relating to these exposures, FirstEnergy uses a variety of non-derivative and derivative instruments, including forward contracts, options, futures contracts and swaps. The derivatives are used principally for hedging purposes, and to a lesser extent, for trading purposes. FirstEnergy's Risk Policy Committee, comprised of members of senior management, provides general management oversight to risk management activities throughout the Company. They are responsible for promoting the effective design and implementation of sound risk management programs. They also oversee compliance with corporate risk management policies and established risk management practices.

How derivative instruments are used and classified determines how they are reported in FirstEnergy's financial statements. FirstEnergy accounts for derivative instruments on its Consolidated Balance Sheet at their fair value unless they meet the normal purchase and normal sales criteria. The changes in the fair value of a derivative instrument are recorded in current earnings, in other comprehensive income, or as part of the value of the hedged item depending on whether or not it is designated as part of a hedge transaction and on the nature of the hedge transaction. FirstEnergy's primary ongoing hedging activity involves cash flow hedges of electricity and natural gas purchases. The maximum periods over which the variability of electricity and natural gas cash flows are hedged are two and three years, respectively. Gains and losses from hedges of commodity price risks are included in net income when the underlying hedged commodities are delivered. Also, gains and losses are included in net income when ineffectiveness occurs on certain natural gas hedges. The impact of ineffectiveness on earnings during 2004 was not material. FirstEnergy entered into interest rate derivative transactions during 2001 to hedge a portion of the anticipated interest payments on debt related to the GPU acquisition. Gains and losses from hedges of anticipated interest payments on acquisition debt are included in net income over the periods that hedged interest payments are made – 5, 10 and 30 years. Gains and losses from derivative contracts are included in other operating expenses. AOCL as of December 31, 2004 includes a net deferred loss of $92 million for derivative hedging activity. The $19 million decrease from the December 31, 2003 balance of $111 million includes an $11 million reduction due to the sale of GLEP, a $3 million reduction related to current hedging activity and a $5 million decrease due to net hedge losses included in earnings during the year. Approximately $14 million (after tax) of the current net deferred loss on derivative instruments in AOCL is expected to be reclassified to earnings during the next twelve months as hedged transactions occur. The fair value of these derivative instruments will continue to fluctuate from period to period based on various market factors.

During 2004, FirstEnergy executed fixed-for-floating interest rate swap agreements, whereby FirstEnergy receives fixed cash flows based on the fixed coupons of the hedged securities and pays variable cash flows based on short-term variable market interest rates (3 and 6 months LIBOR index). These derivatives are treated as fair value hedges of fixed-rate, long-term debt issues – protecting against the risk of changes in the fair value of fixed-rate debt instruments due to lower interest rates. Swap maturities, fixed interest rates received, and interest payment dates match those of the underlying obligations. FirstEnergy entered into interest rate swap agreements on a $900 million notional amount of subsidiaries' senior notes and subordinated debentures with a weighted average fixed interest rate of 5.67%. In addition, FirstEnergy unwound swaps with a total notional amount of $400 million from which it received $12 million in cash gains during 2004. The gains will be recognized over the remaining maturity of each respective hedged security as reduced interest expense. As of December 31, 2004, the aggregate notional value of interest rate swap agreements outstanding was $1.65 billion.

FirstEnergy engages in the trading of commodity derivatives and periodically experiences net open positions. FirstEnergy's risk management policies limit the exposure to market risk from open positions and require daily reporting to management of potential financial exposures. Discretionary trading in 2004 resulted in a $2 million gain.

6. Leases

The Companies lease certain generating facilities, office space and other property and equipment under cancelable and noncancelable leases.

OE sold portions of its ownership interests in Perry Unit 1 and Beaver Valley Unit 2 and entered into operating leases on the portions sold for basic lease terms of approximately 29 years. CEI and TE also sold portions of their ownership interests in Beaver Valley Unit 2 and Bruce Mansfield Units 1, 2 and 3 and entered into similar operating leases for lease terms of approximately 30 years. During the terms of their respective leases, OE, CEI and TE continue to be responsible, to the extent of their individual combined ownership and leasehold interests, for costs associated with the units including construction expenditures, operation and maintenance expenses, insurance, nuclear fuel, property taxes and decommissioning. They have the right, at the expiration of the respective basic lease terms, to renew their respective leases. They also have the right to purchase the facilities at the expiration of the basic lease term or any renewal term at a price equal to the fair market value of the facilities. The basic rental payments are adjusted when applicable federal tax law changes.

Consistent with the regulatory treatment, the rentals for capital and operating leases are charged to operating expenses on the Consolidated Statements of Income. Such costs for the three years ended December 31, 2004 are summarized as follows:

	2004	2003	2002
		(In millions)	
Operating leases			
Interest element	$172	$181	$188
Other	126	150	136
Capital leases			
Interest element	1	2	2
Other	3	2	3
Total rentals	$302	$335	$329

OE invested in the PNBV Capital Trust, which was established to purchase a portion of the lease obligation bonds issued on behalf of lessors in OE's Perry Unit 1 and Beaver Valley Unit 2 sale and leaseback transactions. CEI and TE established the Shippingport Capital Trust to purchase the lease obligation bonds issued on behalf of lessors in their Bruce Mansfield Units 1, 2 and 3 sale and leaseback transactions. The PNBV and Shippingport Capital Trust arrangements effectively reduce lease costs related to those transactions (see Note 7).

The future minimum lease payments as of December 31, 2004 are:

		Operating Leases		
	Capital Leases	Lease Payments	Capital Trusts	Net
		(In millions)		
2005	$ 5	$ 313	$ 130	$ 183
2006	5	322	142	180
2007	1	299	130	169
2008	1	294	105	189
2009	1	298	111	187
Years thereafter	6	2,217	763	1,454
Total minimum lease payments	19	$3,743	$1,381	$2,362
Executory costs	4			
Net minimum lease payments	15			
Interest portion	4			
Present value of net minimum lease payments	11			
Less current portion	2			
Noncurrent portion	$ 9			

FirstEnergy has recorded above-market lease liabilities for Beaver Valley Unit 2 and the Bruce Mansfield Plant associated with the 1997 merger between OE and Centerior. The total above-market lease obligation of $722 million associated with Beaver Valley Unit 2 is being amortized on a straight-line basis through the end of the lease term in 2017 (approximately $37 million per year). The total above-market lease obligation of $755 million associated with the Bruce Mansfield Plant is being amortized on a straight-line basis through the end of 2016 (approximately $48 million per year). As of December 31, 2004 the above-market lease liabilities for Beaver Valley Unit 2 and the Bruce Mansfield Plant totaled $1.0 billion, of which $85 million is current.

7. Variable Interest Entities

FIN 46R, addresses the consolidation of VIEs, including special-purpose entities, that are not controlled through voting interests or in which the equity investors do not bear the residual economic risks and rewards. FirstEnergy adopted FIN 46R for special-purpose entities as of December 31, 2003 and for all other entities in the first quarter of 2004. The first step under FIN 46R is to determine whether an entity is within the scope of FIN 46R, which occurs if it is deemed to be a VIE. FirstEnergy and its subsidiaries consolidate VIEs where they have determined that they are the primary beneficiaries as defined by FIN 46R.

Leases

Included in FirstEnergy's consolidated financial statements are PNBV and Shippingport, two VIEs created in 1996 and 1997, respectively, to refinance debt originally issued in connection with the sale and leaseback transactions discussed above in Note 6. PNBV and Shippingport financial data are included in the consolidated financial statements of OE and CEI, respectively.

PNBV was established to purchase a portion of the lease obligation bonds issued in connection with OE's 1987 sale and leaseback of its interests in the Perry Plant and Beaver Valley Unit 2. OE used debt and available funds to purchase the notes issued by PNBV. Ownership of PNBV includes a three-percent equity interest by a nonaffiliated third party and a three-percent equity interest held by OES Ventures, a wholly owned subsidiary of OE. Shippingport was established to purchase all of the lease obligation bonds issued in connection with CEI's and TE's Bruce Mansfield Plant sale and leaseback transaction in 1987. CEI and TE used debt and available funds to purchase the notes issued by Shippingport.

Through its investment in PNBV, OE has, and through their investments in Shippingport, CEI and TE have, variable interests in certain owner trusts that acquired the interests in the Perry Plant and Beaver Valley Unit 2, in the case of OE, and the Bruce Mansfield Plant, in the case of CEI and TE. FirstEnergy concluded that OE, CEI and TE were not the primary beneficiaries of the relevant owner trusts and were therefore not required to consolidate these entities. The combined purchase price of $3.1 billion for all of the interests acquired by the owner trusts in 1987 was funded with debt of $2.5 billion and equity of $600 million.

OE, CEI and TE are exposed to losses under the applicable sale-leaseback agreements upon the occurrence of certain contingent events that each company considers unlikely to occur. OE, CEI and TE each have a maximum exposure to loss under these provisions of approximately $1 billion, which represents the net amount of casualty value payments upon the occurrence of specified casualty events that render the applicable plant worthless. Under the applicable sale and leaseback agreements, OE, CEI and TE have net minimum discounted lease payments of $673 million, $115 million and $570 million, respectively, that would not be payable if the casualty value payments are made.

Power Purchase Agreements

FirstEnergy has evaluated its power purchase agreements and determined that certain NUG entities may be VIEs to the extent they own a plant that sells substantially all of its output to the Companies and the contract price for power is correlated with the plant's variable costs of production. FirstEnergy, through its subsidiaries JCP&L, Met-Ed and Penelec, maintains approximately 30 long-term power purchase agreements with NUG entities. The agreements were structured pursuant to the Public Utility Regulatory Policies Act of 1978. FirstEnergy was not involved in the creation of, and has no equity or debt invested in, these entities.

FirstEnergy has determined that for all but nine of these entities, neither JCP&L, Met-Ed nor Penelec have variable interests in the entities or the entities are governmental or not-for-profit organizations not within the scope of FIN 46R. JCP&L, Met-Ed or Penelec may hold variable interests in the remaining nine entities, which sell their output at variable prices that correlate to some extent with the operating costs of the plants.

As required by FIN 46R, FirstEnergy requests, on a quarterly basis, the information necessary from these nine entities to determine whether they are VIEs or whether JCP&L, Met-Ed or Penelec is the primary beneficiary. FirstEnergy has been unable to obtain the requested information, which in most cases was deemed by the requested entity to be proprietary. As such, FirstEnergy applied the scope exception that exempts enterprises unable to obtain the necessary information to evaluate entities under FIN 46R. The maximum exposure to loss from these entities results from increases in the variable pricing component under the contract terms and cannot be determined without the requested data. The cost of power purchased from these entities during 2004, 2003 and 2002 was $210 million, $194 million and $184 million, respectively.

FirstEnergy is required to continue to make exhaustive efforts to obtain the necessary information in future periods and is unable to determine the possible impact of consolidating any such entity without this information.

8. Divestitures

International Operations

FirstEnergy completed the sale of its international operations in January 2004 with the sales of its remaining 20.1

percent interest in Avon (parent of Midlands Electricity in the United Kingdom) on January 16, 2004, and its 28.67 percent interest in TEBSA for $12 million on January 30, 2004. Impairment charges related to TEBSA and Avon (included in Other Operating Expenses on the Consolidated Statements of Income) were recorded in the fourth quarter of 2003 and no gain or loss was recognized upon the sales in 2004. Avon, TEBSA and other international assets sold in 2003 were originally acquired as part of FirstEnergy's November 2001 merger with GPU.

International operations in Bolivia were divested by the December 2003 sale of FirstEnergy's wholly owned subsidiary, Guaracachi America, Inc., a holding company with a 50.001 percent interest in EGSA, resulting in a loss on sale of $33 million (recognized in Discontinued Operations in the Consolidated Statement of Income for the year ended December 31, 2003). International operations in Argentina represented by FirstEnergy's ownership in Emdersa were divested through the abandonment of its shares in Emdersa's parent company, GPU Argentina Holdings, Inc. in April 2003. As a result of the abandonment, FirstEnergy recognized a one-time, non-cash charge of $67 million, or $0.23 per share of common stock in the second quarter of 2003. The charge did not include the expected income tax benefits related to the abandonment, which were fully reserved during the second quarter of 2003. FirstEnergy expects tax benefits of approximately $129 million, of which $50 million would increase net income in the period that it becomes probable those benefits will be realized. The remaining $79 million of tax benefits would reduce goodwill recognized in connection with the acquisition of GPU.

FirstEnergy had sold a 79.9 percent equity interest in Avon in May 2002 to Aquila, Inc. for approximately $1.9 billion (consisting of the assumption of $1.7 billion of debt, $155 million in cash and a $87 million note receivable). In the fourth quarter of 2002, FirstEnergy recorded a $50 million after-tax charge to reduce the carrying value of its remaining 20.1 percent interest. After reaching agreement to sell its remaining 20.1 percent interest in the fourth quarter of 2003, FirstEnergy recorded a $5 million after-tax charge to reduce the carrying value. These charges were included in Other Operating Expenses on the Consolidated Statements of Income for the years ended December 31, 2002 and 2003, respectively. In the second quarter of 2003, FirstEnergy recognized an impairment of $13 million ($8 million net of tax) related to the carrying value of the note receivable from Aquila. After receiving the first annual installment payment of $19 million in May 2003, FirstEnergy sold the remaining balance of its note receivable in the secondary market and received $63 million in proceeds in July 2003.

Generation Assets

In August 2002, FirstEnergy cancelled a November 2001 agreement to sell four coal-fired power plants (2,535 MW) to NRG Energy Inc. because NRG stated that it could not complete the transaction under the original terms of the agreement. NRG filed voluntary bankruptcy petitions in May 2003; subsequently, FirstEnergy reached an agreement for settlement of its claim against NRG. FirstEnergy sold its entire claim (including $32 million of cash proceeds received in December 2003) for $170 million in January 2004.

Other Domestic Operations

FirstEnergy sold its 50 percent interest in GLEP on June 23, 2004. Proceeds of $220 million included cash of $200 million and the right, valued at $20 million, to participate for up to a 40% interest in future wells in Ohio. This transaction produced an after-tax loss of $7 million, or $0.02 per share of common stock, including the benefits of prior tax capital losses that had been previously fully reserved, which offset the capital gain from the sale. In 2003, FirstEnergy sold three FSG subsidiaries – Ancoma, Inc., a mechanical contracting company based in Rochester, New York, and Virginia-based Colonial Mechanical and Webb Technologies – and a MARBEL subsidiary – Northeast Ohio Natural Gas (see Note 2(J)).

9. Regulatory Matters

Reliability Initiatives

In late 2003 and early 2004, a series of letters, reports and recommendations were issued from various entities, including governmental, industry and ad hoc reliability entities (PUCO, FERC, NERC and the U.S. – Canada Power System Outage Task Force) regarding enhancements to regional reliability. With respect to each of these reliability enhancement initiatives, FirstEnergy submitted its response to the respective entity according to any required response dates. In 2004, FirstEnergy completed implementation of all actions and initiatives related to enhancing area reliability, improving voltage and reactive management, operator readiness and training, and emergency response preparedness recommended for completion in 2004. Furthermore, FirstEnergy certified to NERC on June 30, 2004, with minor exceptions noted, that FirstEnergy had completed the recommended enhancements, policies, procedures and actions it had recommended be completed by June 30, 2004. In addition, FirstEnergy requested, and NERC provided, a technical assistance team of experts to assist in implementing and confirming timely and successful completion of various initiatives. The NERC-assembled independent verification team confirmed on July 14, 2004, that FirstEnergy had implemented the NERC Recommended Actions to Prevent and Mitigate the Impacts of Future Cascading Blackouts required to be completed by June 30, 2004, as well as NERC recommendations contained in the Control Area Readiness Audit Report required to be completed by summer 2004, and recommendations in the U.S. – Canada Power System Outage Task Force Report directed toward FirstEnergy and required to be completed by June 30, 2004, with minor exceptions noted by FirstEnergy. On December 28, 2004, FirstEnergy submitted a follow-up to its June 30, 2004 Certification and Report of Completion to NERC addressing the minor exceptions, which are now essentially complete.

FirstEnergy is proceeding with the implementation of the recommendations that were to be completed subsequent to 2004 and will continue to periodically assess the FERC-ordered Reliability Study recommendations for forecasted 2009 system conditions, recognizing revised load forecasts and other changing system conditions which may impact the recommendations. Thus far, implementation of the recommendations has not required, nor is expected to require, substantial investment in new, or material upgrades, to existing equipment. FirstEnergy notes, however, that FERC or other applicable government agencies and reliability coordinators may take a different view as to recommended enhancements or may recommend additional enhancements in the future that could require additional, material expenditures. Finally, the PUCO is continuing to review the FirstEnergy filing that addressed upgrades to control room computer hardware and software and enhancements to the training of control room operators, before determining the next steps, if any, in the proceeding.

On July 5, 2003, JCP&L experienced a series of 34.5 kilovolt sub-transmission line faults that resulted in outages on the New Jersey shore. On July 16, 2003, the NJBPU initiated an investigation into the cause of JCP&L's outages of the July 4, 2003 weekend. The NJBPU selected an SRM to oversee and make recommendations on appropriate courses of action necessary to ensure system-wide reliability. Additionally, pursuant to the stipulation of settlement that was adopted in the NJBPU's Order of March 13, 2003 in its docket relating to the investigation of outages in August 2002, the NJBPU, through an independent auditor working under direction of the NJBPU Staff, undertook a review and focused audit of JCP&L's Planning and Operations and Maintenance programs and practices (Focused Audit). Subsequent to the initial engagement of the auditor, the scope of the review was expanded to include the outages during July 2003.

Both the independent auditor and the SRM submitted interim reports primarily addressing improvements to be made prior to the next occurrence of peak loads in the summer of 2004. On December 17, 2003, the NJBPU adopted the SRM's interim recommendations related to service reliability. With the assistance of the independent auditor and the SRM, JCP&L and the NJBPU staff created a Memorandum of Understanding (MOU) that set out specific tasks to be performed by JCP&L and a timetable for completion. On March 29, 2004, the NJBPU adopted the MOU and endorsed JCP&L's ongoing actions to implement the MOU. On June 9, 2004, the NJBPU approved a Stipulation that incorporates the final report of the SRM and the Executive Summary and Recommendation portions of the final report of the Focused Audit. A Final Order in the Focused Audit docket was issued by the NJBPU on July 23, 2004. JCP&L continues to file compliance reports reflecting activities associated with the MOU and Stipulation.

In May 2004, the PPUC issued an order approving the revised reliability benchmark and standards, including revised benchmarks and standards for Met-Ed, Penelec and Penn. Met-Ed, Penelec and Penn filed a Petition for Amendment of Benchmarks with the PPUC on May 26, 2004 seeking amendment of the benchmarks and standards due to their implementation of automated outage management systems following restructuring. Evidentiary hearings have been scheduled for September 2005. FirstEnergy is unable to predict the outcome of this proceeding.

On January 16, 2004, the PPUC initiated a formal investigation of whether Met-Ed's, Penelec's and Penn's "service reliability performance deteriorated to a point below the level of service reliability that existed prior to restructuring" in Pennsylvania. Hearings were held in early August 2004. On September 30, 2004, Met-Ed, Penelec and Penn filed a settlement agreement with the PPUC that addresses the issues related to this investigation. As part of the settlement, Met-Ed, Penelec and Penn agreed to enhance service reliability, ongoing periodic performance reporting and communications with customers and to collectively maintain their current spending levels of at least $255 million annually on combined capital and operation and maintenance expenditures for transmission and distribution for the years 2005 through 2007. The settlement also outlines an expedited remediation process to address any alleged non-compliance with terms of the settlement and an expedited PPUC hearing process if remediation is unsuccessful. On November 4, 2004, the PPUC accepted the recommendation of the ALJ approving the settlement.

Ohio

In October 2003, the Ohio Companies filed an application for a Rate Stabilization Plan with the PUCO to establish generation service rates beginning January 1, 2006, in response to PUCO concerns about price and supply uncertainty following the end of the Ohio Companies' transition plan market development period. On February 24, 2004, the Ohio Companies filed a revised Rate Stabilization Plan to address PUCO concerns related to the original Rate Stabilization Plan. On June 9, 2004, the PUCO issued an order approving the revised Rate Stabilization Plan, subject to conducting a competitive bid process. On August 5, 2004, the Ohio Companies accepted the Rate Stabilization Plan as modified and approved by the PUCO on August 4, 2004. In the second quarter of 2004, the Ohio Companies implemented the accounting modifications related to the extended amortization periods and interest costs deferral on the deferred customer shopping incentive balances. On October 1 and October 4, 2004, the OCC and NOAC, respectively, filed appeals with the Supreme Court of Ohio to overturn the June 9, 2004 PUCO order and associated entries on rehearing.

The revised Rate Stabilization Plan extends current generation prices through 2008, ensuring adequate generation supply at stabilized prices, and continues the Ohio Companies' support of energy efficiency and economic development efforts. Other key components of the revised Rate Stabilization Plan include the following:

- extension of the transition cost amortization period for OE from 2006 to as late as 2007; for CEI from 2008 to as late as mid-2009 and for TE from mid-2007 to as late as mid-2008;
- deferral of interest costs on the accumulated customer shopping incentives as new regulatory assets; and

- ability to request increases in generation charges during 2006 through 2008, under certain limited conditions, for increases in fuel costs and taxes.

On December 9, 2004, the PUCO rejected the auction price results from a required competitive bid process and issued an entry stating that the pricing under the approved revised Rate Stabilization Plan will take effect on January 1, 2006. The PUCO may cause the Ohio Companies to undertake, no more often than annually, a similar competitive bid process to secure generation for the years 2007 and 2008. Any acceptance of future competitive bid results would terminate the Rate Stabilization Plan pricing, but not the related approved accounting, and not until twelve months after the PUCO authorizes such termination.

New Jersey

JCP&L is permitted to defer for future collection from customers the amounts by which its costs of supplying BGS to non-shopping customers and costs incurred under NUG agreements exceed amounts collected through BGS and MTC rates. As of December 31, 2004, the accumulated deferred cost balance totaled approximately $446 million. New Jersey law allows for securitization of JCP&L's deferred balance upon application by JCP&L and a determination by the NJBPU that the conditions of the New Jersey restructuring legislation are met. On February 14, 2003, JCP&L filed for approval of the securitization of the deferred balance. There can be no assurance as to the extent, if any, that the NJBPU will permit such securitization.

In July 2003, the NJBPU announced its JCP&L base electric rate proceeding decision, which reduced JCP&L's annual revenues effective August 1, 2003 and disallowed $153 million of deferred energy costs. The NJBPU decision also provided for an interim return on equity of 9.5% on JCP&L's rate base. The decision ordered a Phase II proceeding be conducted to review whether JCP&L is in compliance with current service reliability and quality standards. The BPU also ordered that any expenditures and projects undertaken by JCP&L to increase its system's reliability be reviewed as part of the Phase II proceeding, to determine their prudence and reasonableness for rate recovery. In that Phase II proceeding, the NJBPU could increase JCP&L's return on equity to 9.75% or decrease it to 9.25%, depending on its assessment of the reliability of JCP&L's service. Any reduction would be retroactive to August 1, 2003. JCP&L recorded charges to net income for the year ended December 31, 2003, aggregating $185 million ($109 million net of tax) consisting of the $153 million of disallowed deferred energy costs and $32 million of other disallowed regulatory assets. In its final decision and order issued on May 17, 2004, the NJPBU clarified the method for calculating interest attributable to the cost disallowances, resulting in a $5.4 million reduction from the amount estimated in 2003. JCP&L filed an August 15, 2003 interim motion for rehearing and reconsideration with the NJBPU and a June 1, 2004 supplemental and amended motion for rehearing and reconsideration. On July 7, 2004, the NJBPU granted limited reconsideration and rehearing on the following issues: (1) deferred cost disallowances (2) the capital structure including the rate of return (3) merger savings, including amortization of costs to achieve merger savings; and (4) decommissioning costs. Management is unable to predict when a decision may be reached by the NJBPU.

On July 16, 2004, JCP&L filed the Phase II petition and testimony with the NJBPU, requesting an increase in base rates of $36 million for the recovery of system reliability costs and a 9.75% return on equity. The filing also requests an increase to the MTC deferred balance recovery of approximately $20 million annually. The Ratepayer Advocate filed testimony on November 16, 2004, and JCP&L submitted rebuttal testimony on January 4, 2005. Settlement conferences are ongoing.

JCP&L sells all self-supplied energy (NUGs and owned generation) to the wholesale market with offsetting credits to its deferred energy balance with the exception of 300 MW from JCP&L's NUG committed supply currently being used to serve BGS customers pursuant to NJBPU order. The BGS auction for periods beginning June 1, 2004 was completed in February 2004 and new BGS tariffs reflecting the auction results became effective June 1, 2004. The NJBPU decision on the BGS post transition year three process was announced on October 22, 2004, approving with minor modifications the BGS procurement process filed by JCP&L and the other New Jersey electric distribution companies and authorizing the continued use of NUG committed supply to serve 300 MW of BGS load. The auction for the supply period beginning June 1, 2005 was completed in February 2005.

In accordance with an April 28, 2004 NJBPU order, JCP&L filed testimony on June 7, 2004 supporting a continuation of the current level and duration of the funding of TMI-2 decommissioning costs by New Jersey customers without a reduction, termination or capping of the funding. On September 30, 2004, JCP&L filed an updated TMI-2 decommissioning study (see Note 11 – Asset Retirement Obligations). This study resulted in an updated total decommissioning cost estimate of $729 million (in 2003 dollars) compared to the estimated $528 million (in 2003 dollars) from the prior 1995 decommissioning study. The Ratepayer Advocate filed comments on February 28, 2005. A schedule for further proceedings has not yet been set.

Pennsylvania

In June 2001, the PPUC approved the Settlement Stipulation with all of the major parties in the combined merger and rate relief proceedings, which approved the FirstEnergy/GPU merger and provided Met-Ed and Penelec PLR deferred accounting treatment for energy costs. A February 2002 Commonwealth Court of Pennsylvania decision affirmed the PPUC decision regarding approval of the merger, remanded the issue of quantification and allocation of merger savings to the PPUC and denied the PLR deferral accounting treatment. In October 2003, the PPUC issued an order concluding that the Commonwealth Court reversed the PPUC's June 2001 order in its entirety. In accordance with the PPUC's direction, Met-Ed and Penelec filed supplements to their tariffs which were effective October 2003 that reflected the CTC rates and shopping credits in effect prior to the June 21, 2001 order.

In response to its October 8, 2003 petition, the PPUC approved June 30, 2004 as the date for Met-Ed's and Penelec's NUG trust fund refunds and denied their accounting request regarding the CTC rate/shopping credit swap by requiring Met-Ed and Penelec to treat the stipulated CTC rates that were in effect from January 1, 2002 on a retroactive basis. Met-Ed and Penelec subsequently filed with the Commonwealth Court, on October 31, 2003, an Application for Clarification with the judge, a Petition for Review of the PPUC's October 2 and October 16 Orders, and an application for reargument if the judge, in his clarification order, indicates that Met-Ed's and Penelec's Objection was intended to be denied on the merits. The Reargument Brief before the Commonwealth Court was filed January 28, 2005.

In accordance with PPUC directives, Met-Ed and Penelec have been negotiating with interested parties in an attempt to resolve the merger savings issues that are the subject of remand from the Commonwealth Court. These companies' combined portion of total merger savings is estimated to be approximately $31.5 million. If no settlement can be reached, Met-Ed and Penelec will take the position that any portion of such savings should be allocated to customers during each company's next rate proceeding.

Met-Ed and Penelec purchase a portion of their PLR requirements from FES through a wholesale power sale agreement. The PLR sale is automatically extended for each successive calendar year unless any party elects to cancel the agreement by November 1 of the preceding year. Under the terms of the wholesale agreement, FES retains the supply obligation and the supply profit and loss risk, for the portion of power supply requirements not self-supplied by Met-Ed and Penelec under their NUG contracts and other power contracts with nonaffiliated third party suppliers. This arrangement reduces Met-Ed's and Penelec's exposure to high wholesale power prices by providing power at a fixed price for their uncommitted PLR energy costs during the term of the agreement with FES. Met-Ed and Penelec are authorized to continue deferring differences between NUG contract costs and current market prices.

Transmission

On November 1, 2004, ATSI requested authority from the FERC to defer approximately $54 million of vegetation management costs ($13 deferred as of December 31, 2004 pending authorization) estimated to be incurred from 2004 through 2007. The FERC approved ATSI's request to defer those costs on March 4, 2005.

ATSI and MISO filed with the FERC on December 2, 2004, seeking approval for ATSI to have transmission rates established based on a FERC-approved cost of service - formula rate included in Attachment O under the MISO tariff. The ATSI Network Service net revenue requirement increased under the formula rate to approximately $159 million. On January 28, 2005, the FERC accepted for filing the revised tariff sheets to become effective February 1, 2005, subject to refund, and ordered a public hearing be held to address the reasonableness of the proposal to eliminate the voltage-differentiated rate design for the ATSI zone.

On December 30, 2004, the Ohio Companies filed an application with the PUCO seeking tariff adjustments to recover increases of approximately $30 million in transmission and ancillary service costs beginning January 1, 2006. The Ohio Companies also filed an application for authority to defer costs associated with MISO Day 1, MISO Day 2, congestion fees, FERC assessment fees, and the ATSI rate increase, as applicable, from October 1, 2003 through December 31, 2005.

On January 12, 2005, Met-Ed and Penelec filed, before the PPUC, a request for deferral of transmission-related costs beginning January 1, 2005, estimated to be approximately $8 million per month.

Various parties have intervened in each of the cases above.

On September 16, 2004, the FERC issued an order that imposed additional obligations on CEI under certain pre-Open Access transmission contracts among CEI and the cities of Cleveland and Painesville. Under the FERC's decision, CEI may be responsible for a portion of new energy market charges imposed by MISO when its energy markets begin in the spring of 2005. CEI filed for rehearing of the order from the FERC on October 18, 2004. The impact of the FERC decision on CEI is dependent upon many factors, including the arrangements made by the cities for transmission service, the startup date for the MISO energy market, and the resolution of the rehearing request, and cannot be determined at this time.

10. Capitalization

(A) COMMON STOCK

Retained Earnings and Dividends

Under applicable federal law, FirstEnergy (as a registered holding company) and its subsidiaries can pay dividends only from retained, undistributed or current earnings, unless the SEC specifically authorizes payment from other capital accounts. As of December 31, 2004, FirstEnergy's unrestricted retained earnings were $1.9 billion. Provisions within the articles of incorporation, indentures and various other agreements relating to the long-term debt and preferred stock of certain FirstEnergy subsidiaries contain provisions that could restrict the payment of dividends on their common and preferred stock. As of December 31, 2004, there were no material restrictions on retained earnings under these agreements for payment of cash dividends on FirstEnergy's common stock.

On November 30, 2004, the Board of Directors increased the indicated annual dividend to $1.65 per share, payable quarterly at a rate of $0.4125 per share, and declared the first quarter 2005 dividend. At December 31, 2004, accrued dividends of approximately $135 million were included in other current liabilities on the Consolidated Balance Sheet. Dividends declared in 2004 were $1.9125 which included quarterly dividends of $0.375 per share paid in each quarter of 2004 and a dividend of $0.4125 payable in the first quarter of 2005. Dividends declared in 2003 were

$1.50, which included quarterly dividends of $0.375 per share paid in each quarter of 2003. The amount and timing of all dividend declarations are subject to the discretion of the Board and its consideration of business conditions, results of operations, financial conditions and other factors.

(B) PREFERRED AND PREFERENCE STOCK

All preferred stock may be redeemed by the Companies in whole, or in part, with 30-90 days' notice.

CEI will exercise its option to redeem all outstanding shares of two series of preferred stock during the first quarter of 2005 as follows:

Series	Outstanding Shares	Call Price
7.40A	500,000	101.00
L	474,000	100.00

Met-Ed's and Penelec's preferred stock authorizations consist of 10 million and 11.435 million shares, respectively, without par value. No preferred shares are currently outstanding for those companies.

The Companies' preference stock authorization consists of 8 million shares without par value for OE; 3 million shares without par value for CEI; and 5 million shares, $25 par value for TE. No preference shares are currently outstanding.

(C) LONG-TERM DEBT AND OTHER LONG-TERM OBLIGATIONS

Preferred Stock Subject to Mandatory Redemption

SFAS 150 requires financial instruments issued in the form of shares that are mandatorily redeemable to be classified as long-term debt. Annual sinking fund provisions for the Companies' preferred stock are as follows:

	Series	Shares	Redemption Price Per Share
CEI	$ 7.35C	10,000	$100
Penn	7.625%	7,500	100

Annual sinking fund requirements will be satisfied by the end of 2008 and consist of $1.8 million in 2005 and 2006, $12.3 million in 2007 and $1.0 million in 2008.

Subordinated Debentures to Affiliated Trusts

As of December 31, 2004, CEI's wholly owned statutory business trust, Cleveland Electric Financing Trust, had $100 million of outstanding 9.00% preferred securities maturing in 2031. The sole assets of the trust are CEI's subordinated debentures with the same rate and maturity date as the preferred securities.

CEI formed the trust to sell preferred securities and invest the gross proceeds in the 9.00% subordinated debentures of CEI. The sole assets of the trust are the applicable subordinated debentures. Interest payment provisions of the subordinated debentures match the distribution payment provisions of the trust's preferred securities. In addition, upon redemption or payment at maturity of subordinated debentures, the trust's preferred securities will be redeemed on a pro rata basis at their liquidation value. Under certain circumstances, the applicable subordinated debentures could be distributed to the holders of the outstanding preferred securities of the trust in the event that the trust is liquidated. CEI has effectively provided a full and unconditional guarantee of payments due on the trust's preferred securities. The trust's preferred securities are redeemable at 100 percent of their principal amount at CEI's option beginning in December 2006. Interest on the subordinated debentures (and therefore distributions on the trust's preferred securities) may be deferred for up to 60 months, but CEI may not pay dividends on, or redeem or acquire, any of its cumulative preferred or common stock until deferred payments on its subordinated debentures are paid in full.

Met-Ed and Penelec had each formed statutory business trusts for substantially similar transactions to those of CEI, with ownership of the respective Met-Ed and Penelec trusts through separate wholly owned limited partnerships. In June 2004 and September 2004, respectively, Met-Ed and Penelec extinguished the subordinated debentures held by their respective trusts, who in turn redeemed their respective preferred securities.

Securitized Transition Bonds

On June 11, 2002, JCP&L Transition Funding LLC (Issuer), a wholly owned limited liability company of JCP&L, sold $320 million of transition bonds to securitize the recovery of JCP&L's bondable stranded costs associated with the previously divested Oyster Creek Nuclear Generating Station.

JCP&L does not own nor did it purchase any of the transition bonds, which are included in long-term debt on FirstEnergy's Consolidated Balance Sheets. The transition bonds represent obligations only of the Issuer and are collateralized solely by the equity and assets of the Issuer, which consist primarily of bondable transition property. The bondable transition property is solely the property of the Issuer.

Bondable transition property represents the irrevocable right of a utility company to charge, collect and receive from its customers, through a non-bypassable TBC, the principal amount and interest on the transition bonds and other fees and expenses associated with their issuance. JCP&L, as servicer, manages and administers the bondable transition property, including the billing, collection and remittance of the TBC, pursuant to a servicing agreement with the Issuer.

Other Long-term Debt

Each of the Companies has a first mortgage indenture under which it issues FMBs secured by a direct first mortgage lien on substantially all of its property and franchises, other than specifically excepted property. FirstEnergy and its subsidiaries have various debt covenants under their respective financing arrangements. The most restrictive of the debt covenants relate to the nonpayment of interest and/or principal on debt and the maintenance of certain financial ratios. The fixed charge ratio and debt-to-capitalization ratio covenants are applicable to only financing arrangements of FirstEnergy, the Ohio Companies and Penn. There also exist cross-default provisions among financing arrangements of

FirstEnergy and the Companies.

Based on the amount of FMBs authenticated by the respective mortgage bond trustees through December 31, 2004, the Companies' annual sinking fund requirements for all FMBs issued under the various mortgage indentures amounts to $71 million. OE and Penn expect to deposit funds with their respective mortgage bond trustees in 2005 that will then be withdrawn upon the surrender for cancellation of a like principal amount of FMBs, specifically authenticated for such purposes against unfunded property additions or against previously retired FMBs. This method can result in minor increases in the amount of the annual sinking fund requirement. JCP&L, Met-Ed and Penelec expect to fulfill their sinking fund obligations by providing bondable property additions and/or previously retired FMBs to the respective mortgage bond trustees.

Sinking fund requirements for FMBs and maturing long-term debt (excluding capital leases) for the next five years are:

	(In millions)
2005	$ 937
2006	1,327
2007	453
2008	470
2009	285

Included in the table above are amounts for various variable interest rate pollution control bonds which have provisions by which individual debt holders have the option to "put back" or require the respective debt issuer to redeem their debt at those times when the interest rate may change prior to its maturity date. These amounts are $442 million and $132 million in 2005 and 2008, respectively, representing the next times the debt holders may exercise this provision.

The Companies' obligations to repay certain pollution control revenue bonds are secured by several series of FMBs. Certain pollution control revenue bonds are entitled to the benefit of irrevocable bank LOCs of $299 million or noncancelable municipal bond insurance policies of $922 million to pay principal of, or interest on, the applicable pollution control revenue bonds. To the extent that drawings are made under the LOCs or the policies, the Companies are entitled to a credit against their obligation to repay those bonds. The Companies pay annual fees of 1.0% to 1.7% of the amounts of the LOCs to the issuing banks and 0.20% to 0.55% of the amounts of the policies to the insurers and are obligated to reimburse the banks or insurers, as the case may be, for any drawings thereunder.

FirstEnergy had unsecured borrowings of $215 million as of December 31, 2004, under its $1 billion revolving credit facility agreement which expires June 22, 2007. FirstEnergy currently pays an annual facility fee of 0.30% on the total credit facility amount. FirstEnergy had no borrowings as of December 31, 2004 under a $375 million long-term revolving credit facility agreement, which expires October 23, 2006. FirstEnergy currently pays an annual facility fee of 0.50% on the total credit facility amount. The fees are subject to change based on changes to FirstEnergy's credit ratings.

OE had no unsecured borrowings as of December 31, 2004 under a $250 million long-term revolving credit facility agreement, which expires May 12, 2005. OE currently pays an annual facility fee of 0.20% on the total credit facility amount. OE had no unsecured borrowings as of December 31, 2004 under a $125 million long-term revolving credit facility, which expires October 23, 2006. OE currently pays an annual facility fee of 0.25% on the total credit facility amount. The fees are subject to change based on changes to OE's credit ratings.

OES Finance, Incorporated, a wholly owned subsidiary of OE, had maintained certificates of deposits pledged as collateral to secure reimbursement obligations relating to certain LOCs supporting OE's obligations to lessors under the Beaver Valley Unit 2 sale and leaseback arrangements. In June 2004, these LOCs were replaced by a new LOC, which did not require the collateral deposits. OE entered into a Credit Agreement pursuant to which a standby LOC was issued in support of the replacement LOCs and the issuer of the standby LOC obtained the right to pledge or assign participations in OE's reimbursement obligations to a trust. The trust then issued and sold trust certificates to institutional investors that were designed to be the credit equivalent of an investment directly in OE. The certificates of deposit were cancelled and FirstEnergy received cash proceeds of $278 million in the third quarter of 2004.

CEI and TE have unsecured LOCs of approximately $216 million in connection with the sale and leaseback of Beaver Valley Unit 2 that expire in April 2005. CEI and TE are jointly and severally liable for such LOCs. OE has LOCs of $294 million and $154 million in connection with the sale and leaseback of Beaver Valley Unit 2 and Perry Unit 1, respectively.

11. Asset Retirement Obligations

In January 2003, FirstEnergy implemented SFAS 143, which provides accounting guidance for retirement obligations associated with tangible long-lived assets. This standard requires recognition of the fair value of a liability for an ARO in the period in which it is incurred. The associated asset retirement costs are capitalized as part of the carrying amount of the long-lived asset. Over time the capitalized costs are depreciated and the present value of the ARO increases, resulting in a period expense. However, rate-regulated entities may recognize a regulatory asset or liability instead of an expense if the criteria for such treatment are met. Upon retirement, a gain or loss would be recognized if the cost to settle the retirement obligation differs from the carrying amount.

FirstEnergy has identified applicable legal obligations as defined under the standard for nuclear power plant decommissioning, reclamation of a sludge disposal pond related to the Bruce Mansfield Plant and closure of two coal ash disposal sites. The ARO liability was $1.078 billion as of December 31, 2004 and included $1.063 billion for nuclear decommissioning of the Beaver Valley, Davis-Besse, Perry and TMI-2 nuclear generating facilities. The Companies' share of the obligation to decommission these units was developed based on site specific studies performed by an independent engineer. FirstEnergy utilized an expected cash flow approach to measure the fair value of the nuclear decommissioning ARO.

In the third quarter of 2004, FirstEnergy revised the ARO associated with TMI-2 as the result of a recently completed study and the anticipated operating license extension for TMI-1. The abandoned TMI-2 is adjacent to TMI-1 and the units are expected to be decommissioned concurrently. The decrease in the present value of estimated cash flows associated with the license extension of $202 million was partially offset by the $26 million present value of an increase in projected decommissioning costs. The net decrease in the TMI-2 ARO liability and corresponding regulatory asset was $176 million.

The Companies maintain nuclear decommissioning trust funds that are legally restricted for purposes of settling the nuclear decommissioning ARO. As of December 31, 2004, the fair value of the decommissioning trust assets was $1.583 billion.

The following table describes the changes to the ARO balances during 2004 and 2003.

ARO Reconciliation	2004	2003
	(In millions)	
Balance at beginning of year	$1,179	$1,109
Liabilities incurred	—	—
Liabilities settled	—	—
Accretion	75	70
Revisions in estimated cash flows	(176)	—
Balance at end of year	$1,078	$1,179

The following table describes the changes to the ARO for 2002, as if SFAS 143 had been adopted on January 1, 2002.

Adjusted ARO Reconciliation	2002
	(In millions)
Beginning balance as of January 1, 2002	$1,042
Accretion	67
Ending balance as of December 31, 2002	$1,109

The following table provides the effect on income as if SFAS 143 had been applied during 2002.

Effect of the Change in Accounting Principle Applied Retroactively	
	(In millions)
Reported net income	$553
Increase (Decrease):	
Elimination of decommissioning expense	88
Depreciation of asset retirement cost	(3)
Accretion of ARO liability	(38)
Non-regulated generation cost of removal component, net	15
Income tax effect	(25)
Net earnings increase	37
Net income adjusted	$590
Basic earnings per share of common stock:	
Net income as previously reported	$1.89
Adjustment for effect of change in accounting principle applied retroactively	0.12
Net income adjusted	$2.01
Diluted earnings per share of common stock:	
Net income as previously reported	$1.88
Adjustment for effect of change in accounting principle applied retroactively	0.12
Net income adjusted	$2.00

12. Short-Term Borrowings and Bank Lines of Credit:

Short-term borrowings outstanding as of December 31, 2004, consisted of $29 million of OE bank borrowings and $142 million of OES Capital, Incorporated borrowings. OES Capital is a wholly owned subsidiary of OE whose borrowings are secured by customer accounts receivable purchased from OE. OES Capital can borrow up to $170 million under a receivables financing arrangement at rates based on certain bank commercial paper and is required to pay an annual fee of 0.25% on the amount of the entire finance limit. The receivables financing agreement expires in October 2005. Penn, Met-Ed and Penelec have, through separate wholly owned subsidiaries, receivables financing arrangements that provide a combined borrowing capability of up to $180 million at rates based on bank commercial paper rates. The financing arrangements require payment of an annual facility fee of 0.30% on the entire finance limit. The receivables financing agreements for Penn, Met-Ed and Penelec expire in March 2005. These receivables financing arrangements are expected to be renewed prior to expiration.

OE has various bi-lateral credit facilities with domestic banks that provide for borrowings of up to $34 million under various interest rate options. To assure the availability of these lines, OE is required to pay annual commitment fees that vary from 0.20% to 0.25% of total lender commitments. These lines expire at various times during 2005. The weighted average interest rates on short-term borrowings outstanding as of December 31, 2004 and 2003 were 2.35% and 2.14%, respectively.

CEI and TE sell substantially all of their retail customer receivables to CFC, a wholly owned subsidiary of CEI. CFC subsequently transfers the receivables to a trust under an asset-backed securitization agreement. The trust is a "qualified special purpose entity" under SFAS 140, which provides it with certain rights relative to the transferred assets. Transfers are made in return for an interest in the trust (62% as of December 31, 2004), which is stated at fair value, reflecting adjustments for anticipated credit losses. The fair value of CFC's interest in the trust approximates the stated value of its retained interest in the underlying receivables, after adjusting for anticipated credit losses, because the average collection period is 27 days. Accordingly, subsequent measurements of the retained interest under SFAS 115, (as an available-for-sale financial instrument) result in no material change in value. Sensitivity analyses reflecting 10% and 20% increases in the rate of anticipated credit losses would not have significantly affected FirstEnergy's retained interest in the pool of receivables through the trust.

Of the $222 million sold to the trust and outstanding as of December 31, 2004, FirstEnergy retained interests in $138 million of the receivables. Accordingly, receivables recorded as other receivables on the Consolidated Balance Sheets were reduced by approximately $84 million due to these sales. Collections of receivables previously transferred to the trust and used for the purchase of new receivables from CFC during 2004 totaled approximately $2.5 billion. CEI and TE processed receivables for the trust and received servicing fees of approximately $4.8 million in 2004. Expenses associated with the factoring discount related to the sale of receivables were $3.5 million in 2004.

13. Commitments, Guarantees and Contingencies:

(A) NUCLEAR INSURANCE-

The Price-Anderson Act limits the public liability relative to a single incident at a nuclear power plant to $10.8 billion. The amount is covered by a combination of private insurance and an industry retrospective rating plan. The Companies' maximum potential assessment under the industry retrospective rating plan would be $402 million per incident but not more than $40 million in any one year for each incident.

The Companies are also insured under policies for each nuclear plant. Under these policies, up to $2.75 billion is provided for property damage and decontamination costs. The Companies have also obtained approximately $1.5 billion of insurance coverage for replacement power costs. Under these policies, the Companies can be assessed a maximum of approximately $67.5 million for incidents at any covered nuclear facility occurring during a policy year which are in excess of accumulated funds available to the insurer for paying losses.

The Companies intend to maintain insurance against nuclear risks as long as it is available. To the extent that replacement power, property damage, decontamination, repair and replacement costs and other such costs arising from a nuclear incident at any of the Companies' plants exceed the policy limits of the insurance in effect with respect to that plant, to the extent a nuclear incident is determined not to be covered by the Companies' insurance policies, or to the extent such insurance becomes unavailable in the future, the Companies would remain at risk for such costs.

(B) GUARANTEES AND OTHER ASSURANCES-

As part of normal business activities, FirstEnergy enters into various agreements on behalf of its subsidiaries to provide financial or performance assurances to third parties. Such agreements include contract guarantees, surety bonds and ratings contingent collateralization provisions. As of December 31, 2004, outstanding guarantees and other assurances aggregated approximately $2.4 billion and included contract guarantees ($1.0 billion), surety bonds ($0.3 billion) and LOC ($1.1 billion).

FirstEnergy guarantees energy and energy-related payments of its subsidiaries involved in energy commodity activities – principally to facilitate normal physical transactions involving electricity, gas, emission allowances and coal. FirstEnergy also provides guarantees to various providers of subsidiary financing principally for the acquisition of property, plant and equipment. These agreements legally obligate FirstEnergy to fulfill the obligations of those subsidiaries directly involved in energy and energy-related transactions or financing where the law might otherwise limit the counterparties' claims. If demands of a counterparty were to exceed the ability of a subsidiary to satisfy existing obligations, FirstEnergy's guarantee enables the counterparty's legal claim to be satisfied by other FirstEnergy assets. The likelihood is remote that such parental guarantees of $0.9 billion (included in the $1.0 billion discussed above) as of December 31, 2004 will increase amounts otherwise to be paid by FirstEnergy to meet its obligations incurred in connection with financings and ongoing energy and energy-related activities.

While these types of guarantees are normally parental commitments for the future payment of subsidiary obligations, subsequent to the occurrence of a credit rating downgrade or "material adverse event" the immediate posting of cash collateral or provision of an LOC may be required of the subsidiary. The following table summarizes collateral provisions as of December 31, 2004:

Collateral Provisions	Exposure	Collateral Paid Cash	LOC	Remaining Exposure[1]
		(In millions)		
Credit rating downgrade	$349	$162	$18	$169
Adverse Event	135	—	22	113
Total	$484	$162	$40	$282

[1] As of February 7, 2005, the total exposure decreased to $476 million and the remaining exposure increased to $290 million - net of $146 million of cash collateral and $40 million of LOC collateral provided by counterparties.

Most of FirstEnergy's surety bonds are backed by various indemnities common within the insurance industry. Surety bonds and related FirstEnergy guarantees of $279 million provide additional assurance to outside parties that contractual and statutory obligations will be met in a number of areas including construction jobs, environmental commitments and various retail transactions.

FirstEnergy has also guaranteed the obligations of the operators of the TEBSA project, up to a maximum of $6 million (subject to escalation) under the project's operations and maintenance agreement. In connection with the sale of TEBSA in January 2004, the purchaser indemnified FirstEnergy against any loss under this guarantee. FirstEnergy has also provided an LOC (currently at $47 million), which is renewable and declines yearly based upon the senior outstanding debt of TEBSA.

(C) ENVIRONMENTAL MATTERS

Various federal, state and local authorities regulate the Companies with regard to air and water quality and other environmental matters. The effects of compliance on the Companies with regard to environmental matters could have a material adverse effect on FirstEnergy's earnings and competitive position. These environmental regulations affect FirstEnergy's earnings and competitive position to the extent that it competes with companies that are not subject to such regulations and therefore do not bear the risk of costs associated with compliance, or failure to comply, with such regulations. Overall, FirstEnergy believes it is in compliance with existing regulations but is unable to predict future change in regulatory policies and what, if any, the effects of such change would be. FirstEnergy estimates additional capital expenditures for environmental compliance of approximately $430 million for 2005 through 2007.

Clean Air Act Compliance

The Companies are required to meet federally approved SO_2 regulations. Violations of such regulations can result in shutdown of the generating unit involved and/or civil or criminal penalties of up to $32,500 for each day the unit is in violation. The EPA has an interim enforcement policy for SO_2 regulations in Ohio that allows for compliance based on a 30-day averaging period. The Companies cannot predict what action the EPA may take in the future with respect to the interim enforcement policy.

The Companies believe they are complying with SO_2 reduction requirements under the Clean Air Act Amendments of 1990 by burning lower-sulfur fuel, generating more electricity from lower-emitting plants, and/or using emission allowances. NOx reductions required by the 1990 Amendments are being achieved through combustion controls and the generation of more electricity at lower-emitting plants. In September 1998, the EPA finalized regulations requiring additional NOx reductions from the Companies' facilities. The EPA's NOx Transport Rule imposes uniform reductions of NOx emissions (an approximate 85 percent reduction in utility plant NOx emissions from projected 2007 emissions) across a region of nineteen states (including Michigan, New Jersey, Ohio and Pennsylvania) and the District of Columbia based on a conclusion that such NOx emissions are contributing significantly to ozone levels in the eastern United States. The Companies believe their facilities are also complying with the NOx budgets established under State Implementation Plans (SIPs) through combustion controls and post-combustion controls, including Selective Catalytic Reduction and Selective Non-Catalytic Reduction systems, and/or using emission allowances.

National Ambient Air Quality Standards

In July 1997, the EPA promulgated changes in the NAAQS for ozone and proposed a new NAAQS for fine particulate matter. On December 17, 2003, the EPA proposed the "Interstate Air Quality Rule" covering a total of 29 states (including Michigan, New Jersey, Ohio and Pennsylvania) and the District of Columbia based on proposed findings that air pollution emissions from 29 eastern states and the District of Columbia significantly contribute to nonattainment of the NAAQS for fine particles and/or the "8-hour" ozone NAAQS in other states. The EPA has proposed the Interstate Air Quality Rule to "cap-and-trade" NOx and SO_2 emissions in two phases (Phase I in 2010 and Phase II in 2015). According to the EPA, SO_2 emissions would be reduced by approximately 3.6 million tons annually by 2010, across states covered by the rule, with reductions ultimately reaching more than 5.5 million tons annually. NOx emission reductions would measure about 1.5 million tons in 2010 and 1.8 million tons in 2015. The future cost of compliance with these proposed regulations may be substantial and will depend on whether and how they are ultimately implemented by the states in which the Companies operate affected facilities.

Mercury Emissions

In December 2000, the EPA announced it would proceed with the development of regulations regarding hazardous air pollutants from electric power plants, identifying mercury as the hazardous air pollutant of greatest concern. On December 15, 2003, the EPA proposed two different approaches to reduce mercury emissions from coal-fired power plants. The first approach would require plants to install controls known as MACT based on the type of coal burned. According to the EPA, if implemented, the MACT proposal would reduce nationwide mercury emissions from coal-fired power plants by 14 tons to approximately 34 tons per year. The second approach proposes a cap-and-trade program that would reduce mercury emissions in two distinct phases. Initially, mercury emissions would be reduced by 2010 as a "co-benefit" from implementation of SO_2 and NOx emission caps under the EPA's proposed Interstate Air Quality Rule. Phase II of the mercury cap-and-trade program would be implemented in 2018 to cap nationwide mercury emissions from coal-fired power plants at 15 tons per year. The EPA has agreed to choose between these two options and issue a final rule by March 15, 2005. The future cost of compliance with these regulations may be substantial.

W. H. Sammis Plant

In 1999 and 2000, the EPA issued NOV or Compliance Orders to nine utilities covering 44 power plants, including the W. H. Sammis Plant, which is owned by OE and Penn. In addition, the U.S. Department of Justice filed eight civil complaints against various investor-owned utilities, which included a complaint against OE and Penn in the U.S. District Court for the Southern District of Ohio. These cases are referred to as New Source Review cases. The NOV and complaint allege violations of the Clean Air Act based on operation and maintenance of the W. H. Sammis Plant dating back to 1984. The complaint requests permanent injunctive relief to require the installation of "best available control technology" and civil penalties of up to $27,500 per day of violation. On August 7, 2003, the United States District Court for the Southern District of Ohio ruled that 11 projects undertaken at the W. H. Sammis Plant between 1984 and 1998 required pre-construction permits under the Clean Air Act. The ruling concludes the liability phase of the case, which deals with applicability of Prevention of Significant Deterioration provisions of the Clean Air Act. The remedy phase of the trial to address civil penalties and what, if any, actions should be taken to further reduce emissions at the plant has been delayed without rescheduling by the Court because the parties are engaged in meaningful settlement negotiations. The Court indicated, in its August 2003 ruling, that the remedies it "may consider and impose involved a much broader, equitable analysis, requiring the Court to consider air quality, public health, economic impact, and employment consequences. The Court may also consider the less than consistent efforts of the EPA to apply and further enforce the Clean Air Act." The potential penalties that may be imposed, as well as the capital expenditures necessary to comply with substantive remedial measures that may be required, could have a material adverse impact on FirstEnergy's, OE's and Penn's respective financial condition and results of operations. While the parties are engaged in meaningful settlement discussions, management is unable to predict the ultimate outcome of this matter and no liability has been accrued as of December 31, 2004.

Regulation of Hazardous Waste

As a result of the Resource Conservation and Recovery Act of 1976, as amended, and the Toxic Substances Control Act of 1976, federal and state hazardous waste regulations have been promulgated. Certain fossil-fuel combustion waste products, such as coal ash, were exempted from hazardous waste disposal requirements pending the EPA's evaluation of the need for future regulation. The EPA subsequently determined that regulation of coal ash as a hazardous waste is unnecessary. In April 2000, the EPA announced that it will develop national standards regulating disposal of coal ash under its authority to regulate nonhazardous waste.

The Companies have been named as PRPs at waste disposal sites, which may require cleanup under the Comprehensive Environmental Response, Compensation and Liability Act of 1980. Allegations of disposal of hazardous substances at historical sites and the liability involved are often unsubstantiated and subject to dispute; however, federal law provides that all PRPs for a particular site are liable on a joint and several basis. Therefore, environmental liabilities that are considered probable have been recognized on the Consolidated Balance Sheet as of December 31, 2004, based on estimates of the total costs of cleanup, the Companies' proportionate responsibility for such costs and the financial ability of other nonaffiliated entities to pay. In addition, JCP&L has accrued liabilities for environmental remediation of former manufactured gas plants in New Jersey; those costs are being recovered by JCP&L through a non-bypassable SBC. Included in Current Liabilities and Other Noncurrent Liabilities are accrued liabilities aggregating approximately $65 million as of December 31, 2004. The Companies accrue environmental liabilities only when they conclude that it is probable that they have an obligation for such costs and can reasonably determine the amount of such costs. Unasserted claims are reflected in the Companies' determination of environmental liabilities and are accrued in the period that they are both probable and reasonably estimable.

Climate Change

In December 1997, delegates to the United Nations' climate summit in Japan adopted an agreement, the Kyoto Protocol (Protocol), to address global warming by reducing the amount of man-made greenhouse gases emitted by developed countries by 5.2% from 1990 levels between 2008 and 2012. The United States signed the Protocol in 1998 but it failed to receive the two-thirds vote of the United States Senate required for ratification. However, the Bush administration has committed the United States to a voluntary climate change strategy to reduce domestic greenhouse gas intensity – the ratio of emissions to economic output – by 18 percent through 2012.

The Companies cannot currently estimate the financial impact of climate change policies, although the potential restrictions on CO_2 emissions could require significant capital and other expenditures. However, the CO_2 emissions per kilowatt-hour of electricity generated by the Companies is lower than many regional competitors due to the Companies' diversified generation sources which includes low or non-CO_2 emitting gas-fired and nuclear generators.

Clean Water Act

Various water quality regulations, the majority of which are the result of the federal Clean Water Act and its amendments, apply to the Companies' plants. In addition, Ohio, New Jersey and Pennsylvania have water quality standards applicable to the Companies' operations. As provided in the Clean Water Act, authority to grant federal National Pollutant Discharge Elimination System water discharge permits can be assumed by a state. Ohio, New Jersey and Pennsylvania have assumed such authority.

On September 7, 2004, the EPA established new performance standards under Clean Water Act Section 316(b) for reducing impacts on fish and shellfish from cooling water intake structures at certain existing large electric generating plants. The regulations call for reductions in impingement mortality, when aquatic organisms are pinned against screens or other parts of a cooling water intake system and entrainment, which occurs when aquatic species are drawn into a facility's cooling water system. The Companies are conducting comprehensive demonstration studies, due in 2008, to determine the operational measures, equipment or restoration activities, if any, necessary for compliance by their facilities with the performance standards. FirstEnergy is unable to predict the outcome of such studies. Depending on the outcome of such studies, the future cost of compliance with these standards may require material capital expenditures.

(D) OTHER LEGAL PROCEEDINGS-

Power Outages and Related Litigation

In July 1999, the Mid-Atlantic States experienced a severe heat wave, which resulted in power outages throughout the service territories of many electric utilities, including JCP&L's territory. In an investigation into the causes of the outages and the reliability of the transmission and distribution systems of all four New Jersey electric utilities, the NJBPU concluded that there was not a prima facie case demonstrating that, overall, JCP&L provided unsafe, inadequate or improper service to its customers. Two class action lawsuits (subsequently consolidated into a single proceeding) were filed in New Jersey Superior Court in July 1999 against JCP&L, GPU and other GPU companies, seeking compensatory and punitive damages arising from the July 1999 service interruptions in the JCP&L territory.

In August 2002, the trial court granted partial summary judgment to JCP&L and dismissed the plaintiffs' claims for consumer fraud, common law fraud, negligent misrepresentation, and strict product liability. In November 2003, the trial court granted JCP&L's motion to decertify the class and denied plaintiffs' motion to permit into evidence their class-wide damage model indicating damages in excess of $50 million. These class decertification and damage rulings were appealed to the Appellate Division. The Appellate Court issued a decision on July 8, 2004, affirming the decertification of the originally certified class but remanding for certification of a class limited to those customers directly impacted by the outages of transformers in Red Bank, New Jersey. On September 8, 2004, the New Jersey Supreme Court denied the motions filed by plaintiffs and JCP&L for leave to appeal the decision of the Appellate Court. FirstEnergy is unable to predict the outcome of these matters and no liability has been accrued as of December 31, 2004.

On August 14, 2003, various states and parts of southern Canada experienced widespread power outages. The outages affected approximately 1.4 million customers in FirstEnergy's service area. On April 5, 2004, the U.S. – Canada Power System Outage Task Force released its final report on the outages. In the final report, the Task Force concluded, among other things, that the problems leading to the outages began in FirstEnergy's Ohio service area. Specifically, the final report concludes, among other things, that the initiation of the August 14, 2003 power outages resulted from an alleged failure of both FirstEnergy and ECAR to assess and understand perceived inadequacies within the FirstEnergy system; inadequate situational awareness of the developing conditions; and a perceived failure to adequately manage tree growth in certain transmission rights of way. The Task Force also concluded that there was a failure of the interconnected grid's reliability organizations (MISO and PJM) to provide effective real-time diagnostic support. The final report is publicly available through the Department of Energy's website (www.doe.gov). FirstEnergy believes that the final report does not provide a complete and comprehensive picture of the conditions that contributed to the August 14, 2003 power outages and that it does not adequately address the underlying causes of the outages. FirstEnergy remains convinced that the outages cannot be explained by events on any one utility's system. The final report contains 46 "recommendations to prevent or minimize the scope of future blackouts." Forty-five of those recommendations relate to broad industry or policy matters while one, including subparts, relates to activities the Task Force recommends be undertaken by FirstEnergy, MISO, PJM, ECAR, and other parties to correct the causes of the August 14, 2003 power outage. FirstEnergy implemented several initiatives, both prior to and since the August 14, 2003 power outages, which are consistent with these and other recommendations and collectively enhance the reliability of its electric system. FirstEnergy certified to NERC on June 30, 2004, completion of various reliability recommendations and further received independent verification of completion status from a NERC verification team on July 14, 2004 with minor exceptions noted by FirstEnergy (see Note 9). FirstEnergy's implementation of these recommendations included completion of the Task Force recommendations that were directed toward FirstEnergy. As many of these initiatives already were in process, FirstEnergy does not believe that any incremental expenses associated with additional initiatives undertaken during 2004 will have a material effect on its continuing operations or financial results. FirstEnergy notes, however, that the applicable government agencies and reliability coordinators may take a different view as to recommended enhancements or may recommend additional enhancements in the future that could require additional, material expenditures. FirstEnergy has not accrued a liability as of December 31, 2004 for any expenditures in excess of those actually incurred through that date.

Three substantially similar actions were filed in various Ohio state courts by plaintiffs seeking to represent customers who allegedly suffered damages as a result of the August 14, 2003 power outages. All three cases were dismissed for lack of jurisdiction. One case was refiled at the PUCO. The other two cases were appealed. One case was dismissed and no further appeal was sought. The remaining case is pending. In addition to the one case that was refiled at the PUCO, the Ohio Companies were named as respondents in a regulatory proceeding that was initiated at the PUCO in response to complaints alleging failure to provide reasonable and adequate service stemming primarily from the August 14, 2003 power outages.

One complaint has been filed against FirstEnergy in the New York State Supreme Court. In this case, several plaintiffs in the New York City metropolitan area allege that they suffered damages as a result of the August 14, 2003 power outages. None of the plaintiffs are customers of any FirstEnergy affiliate. FirstEnergy filed a motion to dismiss with the Court on October 22, 2004. No timetable for a decision on the motion to dismiss has been established by the Court. No damage estimate has been provided and thus potential liability has not been determined.

FirstEnergy is vigorously defending these actions, but cannot predict the outcome of any of these proceedings or whether any further regulatory proceedings or legal actions may be initiated against the Companies. In particular, if FirstEnergy or its subsidiaries were ultimately determined to have legal liability in connection with these proceedings, it could have a material adverse effect on FirstEnergy's or its subsidiaries' financial condition and results of operations.

Nuclear Plant Matters

FENOC received a subpoena in late 2003 from a grand jury sitting in the United States District Court for the Northern District of Ohio, Eastern Division requesting the production of certain documents and records relating to the inspection and maintenance of the reactor vessel head at the Davis-Besse Nuclear Power Station. On December 10, 2004, FirstEnergy received a letter from the United States Attorney's Office stating that FENOC is a target of the federal grand jury investigation into alleged false statements made to the NRC in the Fall of 2001 in response to NRC Bulletin 2001-01. The letter also said that the designation of FENOC as a target indicates that, in the view of the prosecutors assigned to the matter, it is likely that federal charges will be returned against FENOC by the grand jury. On February 10, 2005, FENOC received an additional subpoena for documents related to root cause reports regarding reactor head degradation and the assessment of reactor head management issues at Davis-Besse.

In addition, FENOC remains subject to possible civil enforcement action by the NRC in connection with the events leading to the Davis-Besse outage in 2002. If it were ultimately determined that FirstEnergy or its subsidiaries has legal liability or is otherwise made subject to enforcement action based on the Davis-Besse outage, it could have a material adverse effect on FirstEnergy's or its subsidiaries' financial condition and results of operations.

On August 12, 2004, the NRC notified FENOC that it will increase its regulatory oversight of the Perry Nuclear Power

Plant as a result of problems with safety system equipment over the past two years. FENOC operates the Perry Nuclear Power Plant, which is either owned or leased by OE, CEI, TE and Penn. Although the NRC noted that the plant continues to operate safely, the agency has indicated that its increased oversight will include an extensive NRC team inspection to assess the equipment problems and the sufficiency of FENOC's corrective actions. The outcome of these matters could include NRC enforcement action or other impacts on operating authority. As a result, these matters could have a material adverse effect on FirstEnergy's or its subsidiaries' financial condition.

Other Legal Matters

There are various lawsuits, claims (including claims for asbestos exposure) and proceedings related to FirstEnergy's normal business operations pending against FirstEnergy and its subsidiaries. The most significant not otherwise discussed above are described below.

Various legal proceedings alleging violations of federal securities laws and related state laws were filed against FirstEnergy in connection with, among other things, the restatements in August 2003 by FirstEnergy and the Ohio Companies of previously reported results, the August 14, 2003 power outages described above, and the extended outage at the Davis-Besse Nuclear Power Station. The lawsuits were filed against FirstEnergy and certain of its officers and directors. On July 27, 2004, FirstEnergy announced that it had reached an agreement to resolve these pending lawsuits. The settlement agreement, which does not constitute any admission of wrongdoing, provides for a total settlement payment of $89.9 million. Of that amount, FirstEnergy's insurance carriers paid $71.92 million, based on a contractual pre-allocation, and FirstEnergy paid $17.98 million, which resulted in an after-tax charge against FirstEnergy's second quarter 2004 earnings of $11 million or $0.03 per share of common stock (basic and diluted). On December 30, 2004, the court approved the settlement.

On October 20, 2004, FirstEnergy was notified by the SEC that the previously disclosed informal inquiry initiated by the SEC's Division of Enforcement in September 2003 relating to the restatements in August 2003 of previously reported results by FirstEnergy and the Ohio Companies, and the Davis-Besse extended outage, have become the subject of a formal order of investigation. The SEC's formal order of investigation also encompasses issues raised during the SEC's examination of FirstEnergy and the Companies under the PUHCA. Concurrent with this notification, FirstEnergy received a subpoena asking for background documents and documents related to the restatements and Davis-Besse issues. On December 30, 2004, FirstEnergy received a second subpoena asking for documents relating to issues raised during the SEC's PUHCA examination. FirstEnergy has cooperated fully with the informal inquiry and will continue to do so with the formal investigation.

If it were ultimately determined that FirstEnergy or its subsidiaries have legal liability or are otherwise made subject to liability based on the above matter, it could have a material adverse effect on FirstEnergy's or its subsidiaries' financial condition and results of operations.

14. Segment Information:

FirstEnergy has three reportable segments: regulated services, competitive electric energy services and facilities (HVAC) services. The aggregate "Other" segments do not individually meet the criteria to be considered a reportable segment. "Other" consists of international businesses that have subsequently been divested, MYR (a construction service company); natural gas operations and telecommunications services. The assets and revenues for the other business operations are below the quantifiable threshold for operating segments for separate disclosure as "reportable segments." FirstEnergy's primary segment is its regulated services segment, whose operations include the regulated sale of electricity and distribution and transmission services by its eight EUOC in Ohio, Pennsylvania and New Jersey. The competitive electric energy services business segment primarily consists of the subsidiaries (FES, FGCO and FENOC) that sell electricity in deregulated markets and operate the generation facilities of OE, CEI, TE and Penn resulting from the deregulation of the Companies' electric generation business (see Note 2(A) – Accounting for the Effects of Regulation).

The regulated services segment designs, constructs, operates and maintains FirstEnergy's regulated transmission and distribution systems. Its revenues are primarily derived from electricity delivery and transition costs recovery. The regulated services segment assets include generating units that are leased to the competitive electric energy services. Its internal revenues represent the rental revenues for the generating unit leases.

The competitive electric energy services segment has responsibility for FirstEnergy generation operations as discussed under Note 2(A). Its net income is primarily derived from revenues from all electric generation sales revenues consisting of generation services to regulated franchise customers who have not chosen an alternative generation supplier, retail sales in deregulated markets and all domestic unregulated electricity sales in the retail and wholesale markets and the related costs of electricity generation and sourcing of commodity requirements. Its net income also reflects the expense of the intersegment generating unit leases discussed above and property tax amounts related to those generating units.

Segment reporting for 2003 and 2002 was reclassified to conform with the current year business segment organization and operations emphasizing FirstEnergy's regulated electric businesses and competitive electric energy operations. A previous reportable segment was the more expansive competitive services segment whose aggregate operations consisted of FirstEnergy generation operations, natural gas commodity sales, providing local and long-distance phone service and other competitive energy related businesses such as facilities services and construction service (MYR) which was viewed as offering a comprehensive menu of energy related services. Management's focus is on its core electric business. This has resulted in a change in performance review analysis from an aggregate view of all competitive services operations to a focus on its competitive electric energy operations. During FirstEnergy's periodic review of reportable segments under SFAS 131, that change resulted in the revision of reportable segments to the separate reporting of competitive electric energy operations, facilities services and including all other competitive services operations in the "Other" segment. Facilities services is being disclosed as a reporting segment due to the subsidiaries qualifying as held for sale (see Note 2 (H)). In addition, certain amounts (including transmission and congestion charges) were reclassified among purchased power, other operating costs and depreciation and amortization to conform with the current year presentation of generation commodity costs. Interest expense on holding company debt and corporate support services revenues and expenses are now included in "Reconciling Items" and "Other" includes those operating segment results described above.

Segment Financial Information

	Regulated Services	Competitive Electric Energy Services	Facilities Services	Other	Reconciling Adjustments	Consolidated
			(In millions)			
2004						
External revenues	$5,395	$6,204	$398	$451	$ 5	$12,453
Internal revenues	318	—	—	—	(318)	—
Total revenues	5,713	6,204	398	451	(313)	12,453
Depreciation and amortization	1,422	35	5	3	34	1,499
Goodwill impairment	—	—	36	—	—	36
Net interest charges	363	37	1	14	252	667
Income taxes	740	72	(10)	(24)	(107)	671
Income before discontinued operations	1,015	104	(36)	41	(250)	874
Discontinued operations	—	—	—	4	—	4
Net income	1,015	104	(36)	45	(250)	878
Total assets	28,341	1,488	135	625	479	31,068
Total goodwill	5,951	24	—	75	—	6,050
Property additions	572	246	3	4	21	846
2003						
External revenues	$5,253	$5,487	$327	$564	$44	$11,675
Internal revenues	319	—	—	—	(319)	—
Total revenues	5,572	5,487	327	564	(275)	11,675
Depreciation and amortization	1,423	29	—	2	38	1,492
Goodwill impairment	—	—	117	—	—	117
Net interest charges	493	44	1	107	164	809
Income taxes	779	(222)	(35)	(18)	(96)	408
Income before discontinued operations and cumulative effect of accounting change	1,063	(320)	(75)	(64)	(180)	424
Discontinued operations	—	—	(6)	(97)	—	(103)
Cumulative effect of accounting change	101	—	—	1	—	102
Net income	1,164	(320)	(81)	(160)	(180)	423
Total assets	29,789	1,423	166	912	620	32,910
Total goodwill	5,993	24	36	75	—	6,128
Property additions	434	335	4	9	74	856
2002						
External revenues	$5,298	$4,825	$383	$907	$40	$11,453
Internal revenues	318	—	—	—	(318)	—
Total revenues	5,616	4,825	383	907	(278)	11,453
Depreciation and amortization	1,413	24	6	2	34	1,479
Net interest charges	588	43	2	134	189	956
Income taxes	722	(88)	2	(14)	(108)	514
Income before discontinued operations	962	(170)	—	21	(195)	618
Discontinued operations	—	—	3	(68)	—	(65)
Net income	962	(170)	3	(47)	(195)	553
Total assets	30,494	1,340	402	1,606	544	34,386
Total goodwill	5,993	24	196	65	—	6,278
Property additions	490	391	6	9	102	998

Reconciling adjustments to segment operating results from internal management reporting to consolidated external financial reporting primarily consists of interest expense related to holding company debt, corporate support services revenues and expenses, fuel marketing revenues, which are reflected as reductions to expenses for internal management reporting purposes and elimination of intersegment transactions.

Products and Services*

Year	Electricity Sales	Energy Related Sales and Services
	(In millions)	
2004	$10,831	$745
2003	10,205	766
2002	9,656	904

** See Note 2(J) for discussion of discontinued operations.*

Geographic Information

Following the sales of international operations in 2002 through January of 2004, less than one percent of FirstEnergy's revenues and assets were in foreign countries in 2003 and 2004. See Note 8 for a discussion of the divestitures.

15. New Accounting Standards and Interpretations

SFAS 153, "Exchanges of Nonmonetary Assets – an amendment of APB Opinion No. 29"

In December 2004, the FASB issued this Statement amending APB 29, which was based on the principle that nonmonetary assets should be measured based on the fair value of the assets exchanged. The guidance in APB 29 included certain exceptions to that principle. SFAS 153 eliminates the exception from fair value measurement for nonmonetary exchanges of similar productive assets and replaces it with an exception for exchanges that do not have commercial substance. This Statement specifies that a nonmonetary exchange has commercial substance if the future cash flows of the entity are expected to change significantly as a result of the exchange. The provisions of this statement are effective for nonmonetary exchanges occurring in fiscal periods beginning after June 15, 2005 and are to be applied prospectively. FirstEnergy is currently evaluating this standard but does not expect it to have a material impact on the financial statements.

SFAS 123 (revised 2004) "Share-Based Payment"

In December 2004, the FASB issued this revision to SFAS 123, which requires expensing stock options in the financial statements. Important to applying the new standard is understanding how to (1) measure the fair value of stock-based compensation awards and (2) recognize the related compensation cost for those awards. For an award to qualify for equity classification, it must meet certain criteria in SFAS 123(R). An award that does not meet those criteria will be classified as a liability and remeasured each period. SFAS 123(R) retains SFAS 123's requirements on accounting for income tax effects of stock-based compensation. The effective date for FirstEnergy is July 1, 2005 and the Company will be applying modified prospective application, without restatement of prior interim periods. Any potential cumulative adjustments have not been determined. FirstEnergy uses the Black-Scholes option-pricing model to value options and will continue to do so upon adoption of SFAS 123(R). The impacts of the fair value recognition provisions of SFAS 123 on FirstEnergy's net income and earnings per share for 2002 through 2004 are disclosed in Note 4. FirstEnergy is considering alternative compensation strategies in conjunction with the adoption of SFAS 123(R).

SFAS 151, "Inventory Costs – an amendment of ARB No. 43, Chapter 4"

In November 2004, the FASB issued this statement to clarify the accounting for abnormal amounts of idle facility expense, freight, handling costs and wasted material (spoilage). Previous guidance stated that in some circumstances these costs may be "so abnormal" that they would require treatment as current period costs. SFAS 151 requires abnormal amounts for these items to always be recorded as current period costs. In addition, this Statement requires that allocation of fixed production overheads to the cost of conversion be based on the normal capacity of the production facilities. The provisions of this statement are effective for inventory costs incurred by FirstEnergy after June 30, 2005. FirstEnergy is currently evaluating this standard but does not expect it to have a material impact on the financial statements.

EITF Issue No. 03-1, "The Meaning of Other-Than-Temporary Impairment and its Application to Certain Investments"

In March 2004, the EITF reached a consensus on the application guidance for Issue 03-1. EITF 03-1 provides a model for determining when investments in certain debt and equity securities are considered other than temporarily impaired. When an impairment is other-than-temporary, the investment must be measured at fair value and the impairment loss recognized in earnings. The recognition and measurement provisions of EITF 03-1, which were to be effective for periods beginning after June 15, 2004, were delayed by the issuance of FSP EITF 03-1-1 in September 2004. During the period of delay, FirstEnergy will continue to evaluate its investments as required by existing authoritative guidance.

EITF Issue No. 03-16, "Accounting for Investments in Limited Liability Companies"

In March 2004, the FASB ratified the final consensus on Issue 03-16. EITF 03-16 requires that an investment in a limited liability company that maintains a "specific ownership account" for each investor should be viewed as similar to an investment in a limited partnership for determining whether the cost or equity method of accounting should be used. The equity method of accounting is generally required for investments that represent more than a three to five percent interest in a limited partnership. EITF 03-16 was adopted by FirstEnergy in the third quarter of 2004 and did not affect the Companies' financial statements.

FSP 109-1, "Application of FASB Statement No. 109, Accounting for Income Taxes, to the Tax Deduction and Qualified Production Activities Provided by the American Jobs Creation Act of 2004"

Issued in December 2004, FSP 109-1 provides guidance related to the provision within the American Jobs Creation At of 2004 (Act) that provides a tax deduction on qualified production activities. The Act includes a tax deduction of up to 9 percent (when fully phased-in) of the lesser of (a) "qualified production activities income," as defined in the Act, or (b) taxable income (after the deduction for the utilization of any net operating loss carryforwards). This tax deduction is limited to 50 percent of W-2 wages paid by the taxpayer. The FASB believes that the deduction should be accounted for as a special deduction in accordance with SFAS No. 109, "Accounting for Income Taxes." FirstEnergy is currently evaluating this FSP but does not expect it to have a material impact on the Company's financial statements.

FSP 106-2, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003"

Issued in May 2004, FSP 106-2 provides guidance on accounting for the effects of the Medicare Act for employers that sponsor postretirement health care plans that provide prescription drug benefits. FSP 106-2 also requires certain disclosures regarding the effect of the federal subsidy provided by the Medicare Act. The effect of the federal subsidy provided under the Medicare Act on FirstEnergy's consolidated financial statements is described in Note 3.

16. Summary of Quarterly Financial Data (Unaudited):

The following summarizes certain consolidated operating results by quarter for 2004 and 2003. Certain financial results have been reclassified from amounts previously reported due to FES' natural gas business qualifying as held for sale in accordance with SFAS 144 as discussed in Note 2(J).

Three Months Ended	March 31, 2004	June 30, 2004	Sept. 30, 2004	Dec. 31, 2004
	(In millions, except per share amounts)			
Revenues	$3,027	$3,041	$3,435	$2,950
Expenses	2,568	2,481	2,771	2,421
Income Before Interest and Income Taxes	459	560	664	529
Net Interest Charges	171	180	151	165
Income Taxes	115	177	215	163
Income Before Discontinued Operations	173	203	298	201
Discontinued Operations (Net of Income Taxes)	1	1	1	1
Net Income	$174	$204	$299	$202
Basic Earnings Per Share of Common Stock:				
Before Discontinued Operations	$0.53	$0.62	$0.91	$0.61
Discontinued Operations	—	—	—	—
Basic Earnings Per Share of Common Stock	$0.53	$0.62	$0.91	$0.61
Diluted Earnings Per Share of Common Stock:				
Before Discontinued Operations	$0.53	$0.62	$0.91	$0.61
Discontinued Operations	—	—	—	—
Diluted Earnings Per Share of Common Stock	$0.53	$0.62	$ 0.91	$0.61

Three Months Ended	March 31, 2003	June 30, 2003	Sept. 30, 2003	Dec. 31, 2003
	(In millions, except per share amounts)			
Revenues	$2,981	$2,728	$3,317	$2,649
Expenses	2,571	2,488	2,833	2,310
Claim Settlement (Note 8)	—	—	—	168
Income Before Interest and Income Taxes	410	240	484	507
Net Interest Charges	205	205	200	199
Income Taxes	93	21	134	160
Income Before Discontinued Operations and Cumulative Effect of Accounting Change	112	14	150	148
Discontinued Operations (Net of Income Taxes)	5	(72)	2	(38)
Cumulative Effect of Accounting Change (Net of Income Taxes)	102	—	—	—
Net Income (Loss)	$ 219	$ (58)	$ 152	$ 110
Basic Earnings (Loss) Per Share of Common Stock:				
Before Discontinued Operations and Cumulative Effect of Accounting Change	$ 0.38	$ 0.05	$ 0.51	$ 0.45
Discontinued Operations	0.01	(0.25)	—	(0.12)
Cumulative Effect of Accounting Change	0.35	—	—	—
Basic Earnings (Loss) Per Share of Common Stock	$ 0.74	$ (0.20)	$ 0.51	$ 0.33
Diluted Earnings (Loss) Per Share of Common Stock:				
Before Discontinued Operations and Cumulative Effect of Accounting Change	$ 0.38	$ 0.05	$ 0.50	$ 0.45
Discontinued Operations	0.01	(0.25)	—	(0.12)
Cumulative Effect of Accounting Change	0.35	—	—	—
Diluted Earnings (Loss) Per Share of Common Stock	$ 0.74	$ (0.20)	$ 0.50	$ 0.33

Results in the second quarter of 2004 included FirstEnergy's sale of its 50 percent interest in GLEP, which produced an after-tax loss of $7 million, or $0.02 per share (see Note 8). Third quarter 2004 results were impacted by a $17 million net-of-tax, or $0.05 per share charge for losses and impairments relating to the divestiture of certain non-core, technology-related investments. Fourth quarter 2004 results included a $37 million net-of-tax, or $0.11 per share, non-cash charge for impairment of goodwill and other assets of FSG as required by SFAS 142 and SFAS 144 (see Note 2 (H)).

The net loss for the second quarter of 2003 included a charge resulting from the NJBPU's decision to disallow recovery by JCP&L of $153 million in deferred energy costs and a $67 million non-cash charge (no tax benefit recognized) from the abandonment of operations in Argentina.

Results for the fourth quarter of 2003 included a $33 million after-tax loss from the divestiture of assets in Bolivia reported as discontinued operations and a $26 million impairment of the equity TEBSA investment in Columbia included in continuing operations. The fourth quarter 2003 results also include a $170 million gain ($168 million net of expenses) from the NRG Energy Inc. settlement claim.

CONSOLIDATED FINANCIAL AND PRO FORMA COMBINED OPERATING STATISTICS *(Unaudited) (see Note 2(J))*

(Dollars in thousands)

	2004	2003	2002	2001	2000	1999	1994
General Financial Information							
Revenues	$12,453,046	$11,674,888	$11,453,354	$ 7,237,011	$ 6,470,488	$ 6,130,004	$2,390,957
Net Income	$ 878,175	$ 422,764	$ 552,804	$ 646,447	$ 598,970	$ 568,299	$ 281,852
SEC Ratio of Earnings to							
Fixed Charges	2.60	1.73	1.88	2.22	2.10	2.01	2.24
Capital Expenditures	$ 731,342	$ 791,834	$ 903,606	$ 887,929	$ 568,711	$ 474,118	$ 258,642
Total Capitalization [(a)]	$18,937,766	$18,413,530	$18,686,388	$21,339,001	$11,204,674	$11,469,795	$5,852,030
Capitalization Ratios [(a)]:							
Common Stockholders' Equity	45.3%	45.0%	37.7%	34.7%	41.5%	39.8%	39.6%
Preferred and Preference Stock:							
Not Subject to Mandatory Redemption	1.8	1.8	1.8	2.2	5.8	5.7	5.6
Subject to Mandatory Redemption	—	—	2.3	2.8	1.4	2.2	0.7
Long-Term Debt	52.9	53.2	58.2	60.3	51.3	52.3	54.1
Total Capitalization	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Average Capital Costs:							
Preferred and Preference Stock	6.51%	6.47%	7.50%	7.90%	7.92%	7.99%	7.15%
Long-Term Debt	5.93%	6.08%	6.56%	6.98%	7.84%	7.65%	8.17%
Common Stock Data							
Earnings per Share [(b)]:							
Basic	$2.67	$1.40	$2.11	$2.85	$2.69	$2.50	$1.97
Diluted	$2.66	$1.40	$2.10	$2.84	$2.69	$2.50	$1.97
Return on Average Common Equity [(b)]	10.4%	5.7%	8.2%	12.9%	13.0%	12.7%	12.4%
Dividends Paid per Share	$1.50	$1.50	$1.50	$1.50	$1.50	$1.50	$1.50
Dividend Payout Ratio [(b)]	56%	107%	71%	53%	56%	60%	76%
Dividend Yield	3.8%	4.3%	4.5%	4.3%	4.8%	6.6%	8.1%
Price/Earnings Ratio [(b)]	14.8	25.1	15.6	12.3	11.7	9.1	9.4
Book Value per Share	$26.20	$25.35	$24.01	$25.29	$21.29	$20.22	$16.15
Market Price per Share	$39.51	$35.20	$32.97	$34.98	$31.56	$22.69	$18.50
Ratio of Market Price to Book Value	151%	139%	137%	138%	148%	112%	115%
Operating Statistics [(c)]							
Generation Kilowatt-Hour Sales (Millions):							
Residential	31,781	31,322	31,937	32,708	32,519	32,616	29,969
Commercial	32,114	32,311	32,892	32,170	33,139	30,311	27,667
Industrial	31,675	32,451	32,726	33,024	31,140	30,422	33,893
Other	504	554	531	536	522	566	1,454
Total Retail	96,074	96,638	98,086	98,438	97,320	93,915	92,983
Total Wholesale	53,268	42,059	30,007	20,240	13,761	14,631	9,389
Total Sales	149,342	138,697	128,093	118,678	111,081	108,546	102,372
Customers Served:							
Residential	3,916,855	3,874,052	3,868,499	3,833,013	3,798,716	3,767,534	3,615,157
Commercial	500,695	496,253	471,440	464,053	472,410	455,919	422,468
Industrial	10,597	10,871	18,416	18,652	18,996	19,549	21,087
Other	5,654	5,635	5,716	5,762	6,001	5,992	7,468
Total	4,433,801	4,386,811	4,364,071	4,321,480	4,296,123	4,248,994	4,066,180
Number of Employees	15,245	15,905	17,560	18,700	18,912	19,470	22,488

[(a)] 2001 capitalization includes approximately $1.4 billion of long-term debt (excluding long-term debt due to be repaid within one year) included in "Liabilities Related to Assets Pending Sale" on the Consolidated Balance Sheet as of December 31, 2001.

[(b)] Before discontinued operations in 2004, 2003 and 2002, and accounting changes in 2003 and 2001.

[(c)] Reflects pro forma combined FirstEnergy and GPU statistics in the years 1999 to 2001 and pro forma combined Ohio Edison, Centerior and GPU statistics in years prior to 1999.

Shareholder Information

Shareholder Services, Transfer Agent and Registrar
FirstEnergy Securities Transfer Company, a subsidiary of FirstEnergy, acts as our own transfer agent and registrar for all stock issues of FirstEnergy and its subsidiaries. Shareholders wanting to transfer stock, or who need assistance or information, can send their stock or write to Shareholder Services, FirstEnergy Corp., 76 South Main Street, Akron, Ohio 44308-1890. Shareholders also can call the following toll-free telephone number, which is valid in the United States, Canada, Puerto Rico and the Virgin Islands, weekdays between 8 a.m. and 4:30 p.m., Eastern Time: 1-800-736-3402. For Internet access to general shareholder information and useful forms, visit our Web site at *www.firstenergycorp.com/ir.*

Stock Listings and Trading
Newspapers generally report FirstEnergy common stock under the abbreviation FSTENGY, but this can vary depending upon the newspaper. The common stock of FirstEnergy and preferred stock of its electric utility subsidiaries are listed on the following stock exchanges:

Company	Stock Exchange	Symbol
FirstEnergy	New York	FE
Jersey Central	New York	JYP
Ohio Edison	New York	OEC
Pennsylvania Power	Philadelphia	PPC
Toledo Edison	New York, OTC American	TED

Dividends
Proposed dates for the payment of FirstEnergy common stock dividends in 2005 are:

Ex-Dividend Date	Record Date	Payment Date
February 3	February 7	March 1
May 4	May 6	June 1
August 3	August 5	September 1
November 3	November 7	December 1

All dividends are subject to declaration by the Board of Directors at its discretion.

Direct Dividend Deposit
Shareholders can have their dividend payments automatically deposited to checking and savings accounts at any financial institution that accepts electronic direct deposits. Use of this free service ensures that payments will be available to you on the payment date, eliminating the possibility of mail delay or lost checks. Contact Shareholder Services to receive an authorization form.

Combining Stock Accounts
If you have more than one stock account and want to combine them, please write or call Shareholder Services and specify the account that you want to retain as well as the registration of each of your accounts.

Stock Investment Plan
Shareholders and others can purchase or sell shares of FirstEnergy common stock through the Company's Stock Investment Plan. Investors who are not registered shareholders can enroll with an initial $250 cash investment. Participants may invest all or some of their dividends or make optional cash payments at any time of at least $25 per payment up to $100,000 annually. Contact Shareholder Services to receive an enrollment form.

Safekeeping of Shares
Shareholders can request that the Company hold their shares of FirstEnergy common stock in safekeeping. To take advantage of this service, shareholders should forward their common stock certificate(s) to the Company along with a signed letter requesting that the Company hold the shares. Shareholders also should state whether future dividends for the held shares are to be reinvested or paid in cash. The certificate(s) should not be endorsed, and registered mail is suggested. The shares will be held in uncertificated form, and we will make certificate(s) available to shareholders upon request at no cost. Shares held in safekeeping will be reported on dividend checks or Stock Investment Plan statements.

Form 10-K Annual Report
Form 10-K, the Annual Report to the Securities and Exchange Commission, will be sent without charge by writing to David W. Whitehead, Corporate Secretary, FirstEnergy Corp., 76 South Main Street, Akron, Ohio 44308-1890.

Institutional Investor and Security Analyst Inquiries
Institutional investors and security analysts should direct inquiries to: Kurt E. Turosky, Director, Investor Relations, 330-384-5500.

Annual Meeting of Shareholders
Shareholders are invited to attend the 2005 Annual Meeting of Shareholders on Tuesday, May 17, at 10:30 a.m. Eastern Time, at the John S. Knight Center, 77 East Mill Street, in Akron, Ohio. Registered shareholders not attending the meeting can appoint a proxy and vote on the items of business by telephone, Internet or by completing and returning the proxy card that is sent to them. Shareholders whose shares are held in the name of a broker can attend the meeting if they present a letter from their broker indicating ownership of FirstEnergy common stock on the record date of March 22, 2005.

FirstEnergy has included as Exhibit 31 to its Annual Report on Form 10-K for fiscal year 2004 filed with the Securities and Exchange Commission certificates of FirstEnergy's Chief Executive Officer and Chief Financial Officer certifying the quality of the Company's public disclosure. FirstEnergy's Chief Executive Officer has also submitted to the New York Stock Exchange (NYSE) a certificate certifying that he was not aware of any violation by FirstEnergy of the NYSE corporate governance listing standards as of the date of the certification.

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FirstEnergy

76 South Main Street, Akron, OH 44308-1890
www.firstenergycorp.com

2004 Annual Report