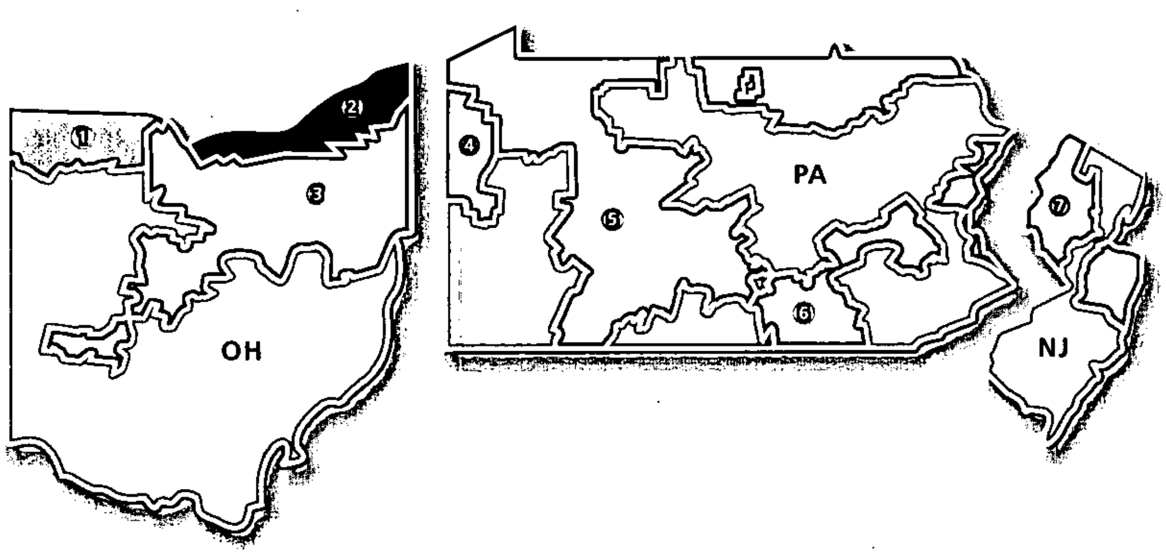
2006 ANNUAL REPORT

FirstEnergy

Electric Utility Operating Companies

1. THE TOLEDO EDISON COMPANY
2. THE CLEVELAND ELECTRIC ILLUMINATING COMPANY
3. OHIO EDISON COMPANY
4. PENNSYLVANIA POWER COMPANY
5. PENNSYLVANIA ELECTRIC COMPANY
6. METROPOLITAN EDISON COMPANY
7. JERSEY CENTRAL POWER & LIGHT COMPANY



Contents

EMPLOYEES ON THE COVER:

SANDRA RUDOLPH, MORRISTOWN, NJ; WALT NEBELSKI, EASTLAKE, OH; MICHELLE WISE, READING, PA; EVAN SUBOTICKI, AKRON, OH

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 4.5 million customers served within a 36,100-square-mile area of Ohio, Pennsylvania and New Jersey.

Financial Highlights

(Dollars in millions, except per share amounts)

	2006	2005
Total revenues	**$11,501**	$11,358
Income from continuing operations*	**$ 1,258**	$ 879
Net income	**$ 1,254**	$ 861
Basic earnings per common share:		
Income from continuing operations	**$ 3.85**	$ 2.68
Net earnings per basic share	**$ 3.84**	$ 2.62
Diluted earnings per common share:		
Income from continuing operations	**$ 3.82**	$ 2.67
Net earnings per diluted share	**$ 3.81**	$ 2.61
Dividends paid per common share**	**$ 1.80**	$ 1.67
Book value per common share	**$ 28.35**	$ 27.98
Net cash from operating activities	**$ 1,939**	$ 2,220

** The 2006 and 2005 discontinued operations are described in Note 2(J) to the consolidated financial statements. The 2005 accounting change is described in Note 2(K).*

*** A quarterly dividend of $0.50 was paid on March 1, 2007, increasing the indicated annual dividend rate to $2.00 per share.*

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, the continued ability of our regulated utilities to collect transition and other charges or to recover increased transmission costs, maintenance costs being higher than anticipated, legislative and regulatory changes (including revised environmental requirements), and the legal and regulatory changes resulting from the implementation of the Energy Policy Act of 2005 (including, but not limited to, the repeal of the Public Utility Holding Company Act of 1935), the uncertainty of the timing and amounts of the capital expenditures needed to, among other things, implement our Air Quality Compliance Plan (including that such amounts could be higher than anticipated) or levels of emission reductions related to the Consent Decree resolving the New Source Review litigation, adverse regulatory or legal decisions and outcomes (including, but not limited to, the revocation of necessary licenses or operating permits, fines or other enforcement actions and remedies) of governmental investigations and oversight, including by the Securities and Exchange Commission, the Nuclear Regulatory Commission and the various state public utility commissions as disclosed in our Securities and Exchange Commission filings, the timing and outcome of various proceedings before the Public Utilities Commission of Ohio (including, but not limited to, the successful resolution of the issues remanded to the PUCO by the Ohio Supreme Court regarding the Rate Stabilization Plan) and the Pennsylvania Public Utility Commission, including, but not limited to, the transition rate plan filings for Met-Ed and Penelec, the continuing availability and operation of generating units, the ability of generating units to continue to operate at, or near full capacity, the inability to accomplish or realize anticipated benefits from strategic goals (including employee workforce initiatives), the anticipated benefits from voluntary pension plan contributions, the ability to improve electric commodity margins and to experience growth in the distribution business, the ability to access the public securities and other capital markets and the cost of such capital, the outcome, cost and other effects of present and potential legal and administrative proceedings and claims related to the August 14, 2003, regional power outage, the successful structuring and completion of a potential sale and leaseback transaction for Bruce Mansfield Unit 1 currently under consideration by management, the successful completion of the share repurchase program announced March 2, 2007, the risks and other factors discussed from time to time in our Securities and Exchange Commission filings, including our annual report on Form 10-K for the year ended December 31, 2006, 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

ANTHONY J. ALEXANDER

In 2006, we achieved our strongest financial and operating performance since our formation nearly a decade ago. We continued to build long-term shareholder value by executing our strategy and accomplishing the goals we set for the year. Significant achievements included:

- Repurchasing nearly 25 million shares of outstanding common stock, or almost 8 percent, since last year
- Attaining an Occupational Safety and Health Administration (OSHA) rate of 0.96 incidents per 100 employees – one of the top safety performances in the industry and the best in our history
- Achieving world-class performance by replacing the steam generators and reactor vessel head at our Beaver Valley Power Station Unit 1 in 65 days – and under budget
- Producing a Company record of 82 million megawatt-hours (MWH) of electricity from our power plants
- Delivering top-decile performance for our bulk transmission system and improving overall distribution reliability by 20 percent
- Hiring more than 1,000 employees to replace those retiring, which helps ensure we maintain the highest level of talent and expertise for future success

Solid Financial Performance

We produced solid financial results in 2006, ending the year with basic earnings per share of $3.84, up significantly from 2005 basic earnings per share of $2.62. We also exceeded our guidance to the financial community for the year.

Earnings growth was driven primarily by increased electric sales revenues, reduced operating expenses, implementation of our Ohio rate plans and deferral of incremental transmission charges in Pennsylvania.

In 2006, we delivered a total annualized return to shareholders of 27.2 percent. This important measure of stock price appreciation plus reinvested dividends reflected a 23-percent increase in our stock price in 2006, which added $3 billion of value for shareholders. Over the past three years, we have delivered an annualized total return of 24 percent and added more than $7 billion in value to our shareholders.

In December, your Board approved an increased quarterly dividend, bringing the new indicated annual dividend to $2.00 per share. This increase – the fourth since March 2005 for a total increase of $0.50 per share annually – underscores the Board's confidence in the Company's direction and prospects for continued success.

"In 2006, we delivered a total annualized return to shareholders of 27.2 percent."

Based on our financial performance, potential for long-term growth and corporate governance practices, *Forbes* magazine once again named FirstEnergy to its annual listing of "The 400 Best Big Companies in America."

Record Safety Performance

There is no more important measure of our success than the safety of our employees, who achieved the lowest OSHA rate in our history last year. Key to this effort were our FirstEnergy Nuclear Operating Company employees, who set a record for personal safety with just one incident for an OSHA rate of 0.03, the best record of any nuclear fleet in the United States.

Mining Our Assets

In 2006, we continued to focus on maximizing the full potential of our assets. We invested nearly $1.2 billion in capital projects at our power plants and in our transmission and distribution systems to increase capacity, environmental performance and reliability.

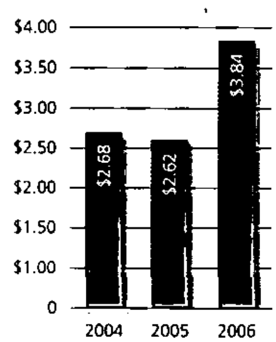
By installing advanced turbine technologies at our baseload coal and nuclear plants, we added 99 megawatts (MW) of capacity, which helped contribute to our record generating performance last year. Consistent with our strategy to achieve incremental generation increases, we expect to add nearly 200 MW of capacity this year at our existing baseload and peaking plants.

Our fossil generating plants set another record in 2006, producing 53 million MWH. Baseload units operated at an 89-percent capacity factor, a top-decile industry performance for the third straight year.

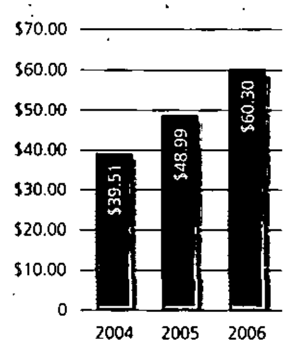
Our nuclear fleet generated 29 million MWH, a significant accomplishment considering that we completed three scheduled refueling outages during the year. And, with replacement of the steam generators and reactor vessel head at Beaver Valley Unit 1 and other enhancements across our nuclear fleet, we believe we are well-positioned to pursue 20-year license extensions for our nuclear plants.

With our plants now in two competitive subsidiaries – FirstEnergy Generation Corp. and FirstEnergy Nuclear Generation Corp. – we are better positioned to succeed in the retail and wholesale marketplace as the states in which we operate move toward fully competitive markets for generation.

BASIC EARNINGS PER SHARE



YEAR-END STOCK PRICE



"Our diversified generation mix remains a key advantage as the industry prepares to address new, more stringent environmental regulations."

Leveraging Technology

We continued to enhance the quality of service to our customers through the use of new technologies, completion of state-of-the-art control centers for three of our operating companies and upgrades to our distribution system.

As a result of these efforts, as well as milder weather for much of our region, more than half a million fewer customers experienced outages last year than in 2005. And, for those who did experience service interruptions, the duration of those outages was reduced by nearly 20 percent on average across our system. Two of our operating companies – Pennsylvania Electric (Penelec) and Pennsylvania Power (Penn Power) – achieved the most notable improvements, with outage durations being reduced by more than 40 percent compared with the previous year.

Our bulk transmission lines – 230 kilovolts and above – ranked among the industry's most reliable in 2006. We continue to derive benefits from enhanced technologies that focus on real-time operations, and comprehensive maintenance of our infrastructure and transmission corridors.

While we are pleased with our progress in enhancing service reliability, we also want to ensure that we are responsive when customers have questions or problems. We continue to receive high marks in this area, with surveys indicating that nearly 85 percent of customers who contact us rate our representatives a 9 or 10 on a 10-point scale.

And, we once again received the Edison Electric Institute's Emergency Assistance award last year. We were recognized for our efforts to restore power to National Grid customers in Buffalo, New York, following a devastating late-fall snowstorm. While we certainly appreciate industry recognition, it was equally gratifying to receive so many notes of thanks from residents for the job our crews did to help bring power back to the area.

Focus on the Environment

Meeting the needs of our customers in an environmentally responsible manner continues to be a priority. Our diversified generation mix remains a key advantage as the industry prepares to address new, more stringent environmental regulations. With more than 60 percent of the electricity we generate coming from scrubbed coal and non-emitting nuclear units, our overall emissions of sulfur-dioxide (SO_2), nitrogen oxides (NO_X) and carbon dioxide (CO_2) per MWH generated are well below regional averages for power generators.

Last year we outlined a $1.8 billion air-quality compliance program designed to meet new federal environmental requirements, including those under the Clean Air Interstate Rule. The centerpiece of this plan is a major environmental retrofit at the W. H. Sammis Plant designed to reduce emissions of SO_2 by at least 95 percent and NO_X by at least 64 percent. This project will add SO_2 scrubbers and NO_X reduction equipment to all seven units at the plant.

We believe our diversified generation mix also means we are better positioned than many of our competitors to manage changes that may come as our nation looks at ways to address global climate change by reducing greenhouse gas emissions such as CO_2.

To that end, we're partnering with government and industry groups to identify and develop the next generation of clean-coal technologies. These include work at our R. E. Burger Plant to test carbon sequestration and capture technologies. We are part of a U.S. Department of Energy initiative with Battelle Memorial Institute to assess the potential to store CO_2 underground in

"As we mark our 10th year as FirstEnergy, I believe we are better positioned than ever before – financially, organizationally and operationally – to meet the challenges that lie ahead."

deep geological formations. And, we're working with New Hampshire-based Powerspan Corp. to test their CO_2 capture technology at the Burger Plant. Additionally, we continue looking for ways to improve the efficiency of our existing units to reduce the amount of CO_2 produced per MWH of generation.

We're also active in CoalFleet for Tomorrow, a partnership with the Electric Power Research Institute to accelerate the development of technologies to reduce the amount of CO_2 produced from the combustion of coal.

And, we continue adding renewable resources to our portfolio with long-term contracts to purchase the output of wind generators under development. We currently have contracts for more than 300 MW of wind capacity, positioning FirstEnergy to be a leading provider of renewable energy in the region.

Building Regulatory Certainty

Through implementation of new rate plans in Ohio last year, we made significant progress on ensuring timely recovery of our investments. Under these plans we will maintain customers' electricity prices through 2008 and defer for future recovery increased fuel costs and investments in our distribution system.

In Ohio, we also began recovering incremental costs associated with our participation in the Midwest Independent Transmission System Operator (MISO). We're doing this through an adjustable charge on customer bills that will collect what we have to pay for MISO's service.

In New Jersey, we received approval to recover $165 million in costs that had been deferred since August 2003 related to mandated contracts with non-utility generation suppliers and the authority to securitize $182 million in costs deferred prior to that time.

In Pennsylvania, we filed the first comprehensive rate case for our Metropolitan Edison and Penelec companies in 14 and 20 years, respectively. A key element of that case – recovery of incremental transmission costs that we pay PJM Interconnection, the regional transmission operator – was approved by the Pennsylvania Public Utility Commission. However, the total revenue increase of $109 million was approximately one-third of our request.

In our Penn Power service territory, we successfully transitioned to market-based generation pricing as part of Pennsylvania's electric competition law. The new prices, which were established through a competitive bid process, went into effect beginning January 1, 2007.

Positioned for Future Success

As we mark our 10th year as FirstEnergy, I believe we are better positioned than ever before – financially, organizationally and operationally – to meet the challenges that lie ahead. With your support, and that of our employees, I am confident in our prospects for continued success.

Sincerely,

Anthony J. Alexander

PRESIDENT AND CHIEF EXECUTIVE OFFICER

MARCH 20, 2007

FirstEnergy Board of Directors

Dear Shareholders:

FirstEnergy management and employees achieved considerable success in 2006 – adding $3 billion to the value of your Company, based on the market capitalization of our common stock. I join our Board members in thanking them for this outstanding performance.

Our record earnings and stronger stock price performance helped FirstEnergy deliver a total shareholder return, including reinvested dividends, of 27.2 percent in 2006 and an annualized return of 24 percent over the past three years.

Given our confidence in the Company's prospects, your Board approved an additional increase in the common stock dividend in 2006, for a total of four increases since March 2005. The new indicated annual dividend of $2.00 per share represents a 33-percent increase during this period.

Your Board also approved two share repurchase programs since June 2006 that retired nearly 25 million shares of FirstEnergy stock. These programs play an important role in our efforts to create additional value for shareholders.

As FirstEnergy achieves these and other key milestones, your Board and management remain committed to the values of good corporate governance and maintenance of the highest ethical standards. In fact, at the beginning of this year, FirstEnergy was outperforming 95 percent of companies in the S&P 500 Index in a commonly used measure of corporate

Paul T. Addison, 60
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, 55
President and Chief Executive Officer of FirstEnergy Corp. Director of FirstEnergy Corp. since 2002.

Michael J. Anderson, 55
President and Chief Executive Officer of The Andersons, Inc., and Chairman of the Board of Interstate Bakeries Corporation. Member, Finance and Nuclear Committees. Director of FirstEnergy Corp. since February 2007.

Dr. Carol A. Cartwright, 65
Retired, formerly President of 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, 61
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.

Robert B. Heisler, Jr., 58
Retired, formerly Chairman of the Board of KeyBank N.A., Chief Executive Officer of the McDonald Financial Group, and Executive Vice President of KeyCorp. Member, Compensation and Finance Committees. Director of FirstEnergy Corp. from 1998-2004 and since 2006.

Russell W. Maier, 70
President and Chief Executive Officer of Michigan Seamless Tube LLC. Chair, Audit Committee; Member, Compensation Committee. Director of FirstEnergy Corp. since 1997 and of Ohio Edison from 1995-1997.

governance effectiveness developed by Institutional Shareholder Services.

On a personal note, let me express my gratitude on behalf of your Board to Russell W. Maier and Robert C. Savage, whose terms as Directors will end with the 2007 Annual Meeting of Shareholders. We thank them for their leadership and dedicated service to shareholders and the Board, and wish them the best in their future pursuits.

I also welcome Michael J. Anderson, who was elected to the Board in January 2007. He serves as President and Chief Executive Officer and a Director of The Andersons, Inc., and as Chairman of the Board of Interstate Bakeries Corporation.

Your Board appreciates your ongoing trust and support. We look forward to representing your interests and working with your management team to meet the challenges and take advantage of the opportunities that lie ahead.

Sincerely,

George M. Smart

George M. Smart
CHAIRMAN OF THE BOARD

Ernest J. Novak, Jr., 62
Retired, formerly Managing Partner of the Cleveland office of Ernst & Young LLP. Member, Audit and Finance Committees. Director of FirstEnergy Corp. since 2004.

Catherine A. Rein, 64
Senior Executive Vice President and Chief Administrative Officer of MetLife Inc. Chair, Compensation Committee; Member, Audit Committee. Director of FirstEnergy Corp. since 2001 and of the former GPU, Inc., from 1989-2001.

Robert C. Savage, 69
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, 61
Non-executive Chairman of the FirstEnergy Board of Directors. Retired, formerly President of Sonoco-Phoenix, Inc. Member, Audit and Corporate Governance Committees. Director of FirstEnergy Corp. since 1997 and of Ohio Edison from 1988-1997.

Wes M. Taylor, 64
Retired, formerly President of TXU Generation. Member, Compensation and Nuclear Committees. Director of FirstEnergy Corp. since 2004.

Jesse T. Williams, Sr., 67
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.

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

James F. Pearson*
VICE PRESIDENT AND TREASURER

Harvey L. Wagner*
VICE PRESIDENT, CONTROLLER AND CHIEF ACCOUNTING OFFICER

David W. Whitehead*
CORPORATE SECRETARY

Paulette R. Chatman*
ASSISTANT CONTROLLER

Jacqueline S. Cooper*
ASSISTANT CORPORATE SECRETARY

Jeffrey R. Kalata*
ASSISTANT CONTROLLER

Randy Scilla*
ASSISTANT TREASURER

Edward J. Udovich*
ASSISTANT CORPORATE SECRETARY

Lisa S. Wilson*
ASSISTANT CONTROLLER

Also holds a similar position 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

Lynn M. Cavalier
SENIOR VICE PRESIDENT

Mark T. Clark
SENIOR VICE PRESIDENT

Gary R. Leidich
SENIOR VICE PRESIDENT

David C. Luff
SENIOR VICE PRESIDENT

Guy L. Pipitone
SENIOR VICE PRESIDENT

Donald R. Schneider
SENIOR VICE PRESIDENT

Carole B. Snyder
SENIOR VICE PRESIDENT

Thomas M. Welsh
SENIOR VICE PRESIDENT

Tony C. Banks
VICE PRESIDENT

David M. Blank
VICE PRESIDENT

Mary Beth Carroll
VICE PRESIDENT

Thomas A. Clark
VICE PRESIDENT

Kathryn W. Dindo
VICE PRESIDENT AND CHIEF RISK OFFICER

Ralph J. DiNicola
VICE PRESIDENT

Michael J. Dowling
VICE PRESIDENT

Bradley S. Ewing
VICE PRESIDENT

Bennett L. Gaines
VICE PRESIDENT AND CHIEF INFORMATION OFFICER

Mark A. Julian
VICE PRESIDENT

Thomas C. Navin
VICE PRESIDENT

Robert P. Reffner
VICE PRESIDENT

Ronald E. Seeholzer
VICE PRESIDENT

Eugene J. Sitarz
VICE PRESIDENT

Daniel V. Steen
VICE PRESIDENT

Stanley F. Szwed
VICE PRESIDENT AND CHIEF FERC COMPLIANCE OFFICER

Bradford F. Tobin
VICE PRESIDENT AND CHIEF PROCUREMENT OFFICER

David W. Whitehead
VICE PRESIDENT, CORPORATE SECRETARY AND CHIEF ETHICS OFFICER

FirstEnergy Solutions Corp.

Charles E. Jones
PRESIDENT

Ali Jamshidi
VICE PRESIDENT

Charles D. Lasky
VICE PRESIDENT

Alfred G. Roth
VICE PRESIDENT

Arthur W. Yuan
VICE PRESIDENT

Dennis J. Fuster*
VICE PRESIDENT, SITE CONSTRUCTION

Frank A. Lubich*
VICE PRESIDENT, W. H. SAMMIS

Brian J. Warnaka*
VICE PRESIDENT, BRUCE MANSFIELD

* *FirstEnergy Generation Corp.*

FirstEnergy Nuclear Operating Company

Anthony J. Alexander
CHIEF EXECUTIVE OFFICER

Joseph J. Hagan
PRESIDENT AND CHIEF NUCLEAR OFFICER

James H. Lash
SENIOR VICE PRESIDENT, FLEET OPERATIONS
VICE PRESIDENT, BEAVER VALLEY

Danny L. Pace
SENIOR VICE PRESIDENT, FLEET ENGINEERING

Richard L. Anderson
VICE PRESIDENT, NUCLEAR OPERATIONS

Jeannie M. Rinckel
VICE PRESIDENT, FLEET OVERSIGHT

Mark B. Bezilla
VICE PRESIDENT, DAVIS-BESSE

L. William Pearce
VICE PRESIDENT, PERRY

FirstEnergy Regional Operations Management

OHIO

James M. Murray
PRESIDENT, OHIO OPERATIONS

Dennis M. Chack
REGIONAL PRESIDENT, THE CLEVELAND ELECTRIC ILLUMINATING COMPANY

Trent A. Smith
REGIONAL PRESIDENT, THE TOLEDO EDISON COMPANY

Steven E. Strah
REGIONAL PRESIDENT, OHIO EDISON COMPANY

PENNSYLVANIA

Douglas S. Elliott
PRESIDENT, PENNSYLVANIA OPERATIONS

Ronald P. Lantzy
REGIONAL PRESIDENT, METROPOLITAN EDISON COMPANY

John E. Paganie
REGIONAL PRESIDENT, PENNSYLVANIA ELECTRIC COMPANY

NEW JERSEY

Stephen E. Morgan
PRESIDENT, JERSEY CENTRAL POWER & LIGHT COMPANY

Donald M. Lynch
REGIONAL PRESIDENT, JERSEY CENTRAL POWER & LIGHT 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
Centerior	Centerior Energy Corporation, former parent of CEI and TE, which merged with OE to form FirstEnergy on November 8, 1997
Companies	OE, CEI, TE, Penn, JCP&L, Met-Ed and Penelec
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., owns and operates non-nuclear generating facilities
FirstCom	First Communications, LLC, provides local and long-distance telephone service
FirstEnergy	FirstEnergy Corp., a public utility holding company
FSG	FirstEnergy Facilities Services Group, LLC, former parent 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
JCP&L	Jersey Central Power & Light Company, a New Jersey electric utility operating subsidiary
JCP&L Transition Funding	JCP&L Transition Funding LLC, a Delaware limited liability company and issuer of transition bonds
JCP&L Transition Funding II	JCP&L Transition Funding II LLC, a Delaware limited liability company and issuer of transition bonds
Met-Ed	Metropolitan Edison Company, a Pennsylvania electric utility operating subsidiary
MYR	MYR Group, Inc., a utility infrastructure construction service company
NGC	FirstEnergy Nuclear Generation Corp., owns nuclear generating facilities
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"
ARO	Asset Retirement Obligation
B&W	Babcock & Wilcox Company
Bechtel	Bechtel Power Corporation
BGS	Basic Generation Service
BTU	British Thermal Unit
CAIR	Clean Air Interstate Rule
CAL	Confirmatory Action Letter
CAMR	Clean Air Mercury Rule
CAT	Commercial Activity Tax
CBP	Competitive Bid Process
CO_2	Carbon Dioxide
CONSOL	CONSOL Energy Inc.
CTC	Competitive Transition Charge
DCPD	Deferred Compensation Plan for Outside Directors
DOJ	United States Department of Justice
DRA	Division of Ratepayer Advocate
ECAR	East Central Area Reliability Coordination Agreement
EDCP	Executive Deferred Compensation Plan
EEI	Edison Electric Institute
EITF	Emerging Issues Task Force
EITF 99-19	EITF Issue No. 99-19, "Reporting Revenue Gross as a Principal versus Net as an Agent"
EPA	Environmental Protection Agency
EPACT	Energy Policy Act of 2005
ERO	Electric Reliability Organization
ESOP	Employee Stock Ownership Plan
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"
FIN 47	FIN 47, "Accounting for Conditional Asset Retirement Obligations - an interpretation of FASB Statement No. 143"
FIN 48	FIN 48, "Accounting for Uncertainty in Income Taxes-an interpretation of FASB Statement No. 109"
Fitch	Fitch Ratings, Ltd.
FMB	First Mortgage Bonds
FSP	FASB Staff Position
FSP SFAS 115-1 and SFAS 124-1	FSP SFAS 115-1 and SFAS 124-1, "The Meaning of Other-Than-Temporary Impairment and its Application to Certain Investments"
GAAP	Accounting Principles Generally Accepted in the United States
GHG	Greenhouse Gases
HVAC	Heating, Ventilation and Air-conditioning
IRS	Internal Revenue Service
KWH	Kilowatt-hours
LOC	Letter of Credit
LTIP	Long-term Incentive Program
MISO	Midwest Independent Transmission System Operator, Inc.
Moody's	Moody's Investors Service
MOU	Memorandum of Understanding
MTC	Market Transition Charge
MW	Megawatts
NAAQS	National Ambient Air Quality Standards
NERC	North American Electric Reliability Corporation
NJBPU	New Jersey Board of Public Utilities
NOPR	Notice of Proposed Rulemaking
NOV	Notice of Violation
NO_X	Nitrogen Oxide
NRC	Nuclear Regulatory Commission
NUG	Non-Utility Generation
NUGC	Non-Utility Generation Charge
OCC	Office of the Ohio Consumers' Counsel
OCI	Other Comprehensive Income
OPEB	Other Post-Employment Benefits
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 of 1935
RCP	Rate Certainty Plan
RFP	Request for Proposal
RSP	Rate Stabilization Plan
RTC	Regulatory Transition Charge
RTO	Regional Transmission Organization
RTOR	Regional Through and Out Rates
S&P	Standard & Poor's Ratings Service
S&P 500	Standard & Poor's Index of Widely Held Common Stocks
SBC	Societal Benefits Charge
SEC	U.S. 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 107	SFAS No. 107, "Disclosure about Fair Value of Financial Instruments"
SFAS 115	SFAS No. 115, "Accounting for Certain Investments in Debt and Equity Securities"
SFAS 123(R)	SFAS No. 123(R), "Share-Based Payment"
SFAS 133	SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities"
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 157	SFAS No. 157, "Fair Value Measurements"
SFAS 158	SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans-an amendment of FASB Statements No. 87, 88, 106, and 132(R)"
SFAS 159	SFAS No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities – Including an Amendment of FASB Statement No. 115"
SIP	State Implementation Plan(s) Under the Clean Air Act
SO_2	Sulfur Dioxide
SRM	Special Reliability Master
TBC	Transition Bond Charge
TMI-1	Three Mile Island Unit 1
TMI-2	Three Mile Island Unit 2
VIE	Variable Interest Entity
VMEP	Vegetation Management Enhancement Project

Management Reports

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 2006 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 ten meetings in 2006.

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 Rule13a-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, 2006. Management's assessment of the effectiveness of the Company's internal control over financial reporting, as of December 31, 2006, 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 integrated audits of FirstEnergy Corp.'s consolidated financial statements and of its internal control over financial reporting as of December 31, 2006, 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 and cash flows present fairly, in all material respects, the financial position of FirstEnergy Corp. and its subsidiaries at December 31, 2006 and 2005, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2006 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 3 to the consolidated financial statements, the Company changed the manner in which it accounts for defined benefit pension and other postretirement benefit plans as of December 31, 2006. As discussed in Note 2(K) and Note 12 to the consolidated financial statements, the Company changed its method of accounting for conditional asset retirement obligations as of December 31, 2005.

INTERNAL CONTROL OVER FINANCIAL REPORTING

Also, in our opinion, management's assessment, included in 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, 2006 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, 2006, 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
February 27, 2007

The following selected financial data should be read in conjunction with, and is qualified in its entirety by reference to, the sections entitled "Management's Discussion and Analysis of Results of Operations and Financial Condition" and with our consolidated financial statements and the "Notes to Consolidated Financial Statements." Our Statements of Income are not necessarily indicative of future conditions or results of operations.

SELECTED FINANCIAL DATA *(In millions, except per share amounts)*

For the Years Ended December 31,	2006	2005	2004	2003	2002
Revenues	**$11,501**	$11,358	$11,600	$10,802	$10,527
Income From Continuing Operations	**$ 1,258**	$ 879	$ 907	$ 494	$ 609
Net Income	**$ 1,254**	$ 861	$ 878	$ 423	$ 553
Basic Earnings per Share of Common Stock:					
Income from continuing operations	**$ 3.85**	$ 2.68	$ 2.77	$ 1.63	$ 2.08
Net earnings per basic share	**$ 3.84**	$ 2.62	$ 2.68	$ 1.39	$ 1.89
Diluted Earnings per Share of Common Stock:					
Income from continuing operations	**$ 3.82**	$ 2.67	$ 2.76	$ 1.62	$ 2.07
Net earnings per diluted share	**$ 3.81**	$ 2.61	$ 2.67	$ 1.39	$ 1.88
Dividends Declared per Share of Common Stock (1)	**$ 1.85**	$ 1.705	$1.9125	$ 1.50	$ 1.50
Total Assets	**$31,196**	$31,841	$31,035	$32,878	$34,366
Capitalization as of December 31:					
Common Stockholders' Equity	**$ 9,035**	$ 9,188	$ 8,590	$ 8,290	$ 7,051
Preferred Stock:					
Not Subject to Mandatory Redemption	–	184	335	335	335
Subject to Mandatory Redemption	–	–	–	–	428
Long-Term Debt and Other Long-Term Obligations	**8,535**	8,155	10,013	9,789	10,872
Total Capitalization	**$17,570**	$17,527	$18,938	$18,414	$18,686
Weighted Average Number of Basic Shares Outstanding	**324**	328	327	304	293
Weighted Average Number of Diluted Shares Outstanding	**327**	330	329	305	294

(1) Dividends declared in 2006 include three quarterly payments of $0.45 per share in 2006 and one quarterly payment of $0.50 per share payable in 2007, increasing the indicated annual dividend rate from $1.80 to $2.00 per share. Dividends declared in 2005 include two quarterly payments of $0.4125 per share in 2005, one quarterly payment of $0.43 per share in 2005 and one quarterly payment of $0.45 per share in 2006. Dividends declared in 2004 include four quarterly dividends of $0.375 per share paid in 2004 and a quarterly dividend of $0.4125 per share paid in 2005. Dividends declared in 2002 and 2003 include four quarterly dividends of $0.375 per share.

PRICE RANGE OF COMMON STOCK

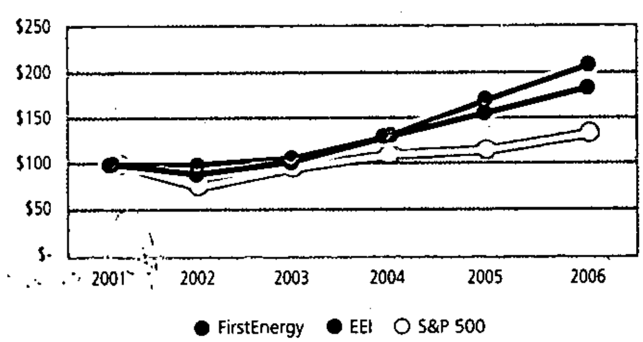
The Common Stock of FirstEnergy Corp. is listed on the New York Stock Exchange under the symbol "FE" and is traded on other registered exchanges.

	2006		2005	
First Quarter High-Low	**$52.17**	**$47.75**	$42.36	$37.70
Second Quarter High-Low	**$54.57**	**$48.23**	$48.96	$40.75
Third Quarter High-Low	**$57.50**	**$53.47**	$53.00	$47.46
Fourth Quarter High-Low	**$61.70**	**$55.99**	$53.36	$45.78
Yearly High-Low	**$61.70**	**$47.75**	$53.36	$37.70

Prices are from http://finance.yahoo.com.

SHAREHOLDER RETURN

The following graph shows the total cumulative return from a $100 investment on December 31, 2001 in FirstEnergy's common stock compared with the total cumulative returns of the EEI's Index of Investor-Owned Electric Utility Companies and the S&P 500.



HOLDERS OF COMMON STOCK

There were 127,400 and 126,821 holders of 319,205,517 shares of FirstEnergy's Common Stock as of December 31, 2006 and January 31, 2007, respectively. Information regarding retained earnings available for payment of cash dividends is given in Note 11(A) to the consolidated financial statements.

Management's Discussion And Analysis Of Results Of Operations And Financial Condition

Forward-Looking Statements: *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. 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, the continued ability of our regulated utilities to collect transition and other charges or to recover increased transmission costs, maintenance costs being higher than anticipated, legislative and regulatory changes (including revised environmental requirements), and the legal and regulatory changes resulting from the implementation of the EPACT (including, but not limited to, the repeal of the PUHCA), the uncertainty of the timing and amounts of the capital expenditures needed to, among other things, implement the Air Quality Compliance Plan (including that such amounts could be higher than anticipated) or levels of emission reductions related to the Consent Decree resolving the New Source Review litigation, adverse regulatory or legal decisions and outcomes (including, but not limited to, the revocation of necessary licenses or operating permits, fines or other enforcement actions and remedies) of governmental investigations and oversight, including by the SEC, the NRC and the various state public utility commissions as disclosed in our SEC filings, generally, and heightened scrutiny at the Perry Nuclear Power Plant in particular, the timing and outcome of various proceedings before the PUCO (including, but not limited to, the successful resolution of the issues remanded to the PUCO by the Ohio Supreme Court regarding the Rate Stabilization Plan) and the PPUC, including the transition rate plan filings for Met-Ed and Penelec, the continuing availability and operation of generating units, the ability of our generating units to continue to operate at, or near full capacity, the inability to accomplish or realize anticipated benefits from strategic goals (including employee workforce initiatives), the anticipated benefits from voluntary pension plan contributions, the ability to improve electric commodity margins and to experience growth in the distribution business, the ability to access the public securities and other capital markets and the cost of such capital, the outcome, cost and other effects of present and potential legal and administrative proceedings and claims related to the August 14, 2003 regional power outage, the successful structuring and completion of a potential sale and leaseback transaction for Bruce Mansfield Unit 1 currently under consideration by management, the successful implementation of the share repurchase program announced January 31, 2007, the risks and other factors discussed from time to time in our SEC filings, and other similar factors. Dividends declared from time to time on FirstEnergy's common stock during any annual period may in aggregate vary from the indicated amounts due to circumstances considered by FirstEnergy's Board of Directors at the time of the actual declarations. Also, a security rating is not a recommendation to buy, sell or hold securities, and it may be subject to revision or withdrawal at any time and each such rating should be evaluated independently of any other rating. We expressly disclaim any current intention to update any forward-looking statements contained herein as a result of new information, future events, or otherwise.*

EXECUTIVE SUMMARY

Net income in 2006 was $1.25 billion, or basic earnings of $3.84 per share of common stock ($3.81 diluted), compared with net income of $861 million, or basic earnings of $2.62 per share ($2.61 diluted) in 2005 and $878 million, or basic earnings of $2.68 per share ($2.67 diluted) in 2004. The increase in FirstEnergy's earnings was driven primarily by increased electric sales revenues, reduced transition cost amortization for the Ohio Companies, cost deferrals authorized by the PUCO and PPUC, and reduced operating expenses.

Change in Basic Earnings Per Share From Prior Year

	2006	2005	2004
Basic Earnings Per Share – Prior Year	$2.62	$2.68	$1.39
PPUC NUG accounting adjustment in 2006	(0.02)	–	–
Trust securities impairment in 2006	(0.02)	–	–
Ohio/New Jersey income tax adjustments in 2005	0.19	(0.19)	–
Sammis Plant New Source Review settlement in 2005	0.04	(0.04)	–
Davis-Besse fine/penalty in 2005	0.10	(0.10)	–
JCP&L arbitration decision in 2005	0.03	(0.03)	–
New regulatory assets - JCP&L settlement in 2005	(0.05)	0.05	–
Lawsuits settlements in 2004	–	0.03	(0.03)
Nuclear operations severance costs in 2004	–	0.01	(0.01)
Davis-Besse extended outage impacts	–	0.12	0.44
Discontinued Operations:			
Non-core asset sales/impairments	(0.02)	0.21	(0.19)
Other	(0.02)	(0.09)	0.67
Revenues	0.26	(0.44)	1.46
Transition costs amortization	0.82	(0.18)	(0.10)
Deferral of new regulatory assets	0.23	0.22	0.12
Fuel and purchased power	(0.43)	0.72	(0.81)
Other expenses	0.24	(0.30)	(0.20)
Investment income	(0.11)	0.02	0.04
Interest expense	(0.11)	0.02	0.23
Cumulative effect of a change in accounting principle	0.09	(0.09)	(0.33)
Basic Earnings Per Share	$3.84	$2.62	$2.68

Total electric generation sales increased 1.1% during 2006 compared to the prior year as a 6.7% increase in retail sales more than offset a 19.1% reduction in wholesale sales. The increase was primarily due to the return of customers to the Ohio Companies from third-party suppliers that exited the northern Ohio marketplace. Electric distribution deliveries were down 2.3% in 2006, compared to 2005, reflecting milder weather conditions in 2006.

Dividends – On December 19, 2006, FirstEnergy's Board of Directors declared a quarterly dividend of $0.50 per share on outstanding common stock payable March 1, 2007. The new indicated annual dividend will be $2.00 per share, $0.20 per share higher than the previous annual level. This action is consistent with our policy, which targets sustainable annual dividend growth and a payout that is appropriate for our level of earnings.

Share Repurchase – On January 30, 2007, FirstEnergy's Board of Directors authorized a new share repurchase program for up to 16 million shares, or approximately 5% of FirstEnergy's outstanding common stock. This new program supplements the prior repurchase program approved on June 20, 2006, such that up to 26.6 million potential shares may ultimately be repurchased under the combined plans. At management's discretion, shares may be acquired on the open market or through privately negotiated transactions, subject to market conditions and other factors. The Board's authorization of the repurchase program does not require FirstEnergy to purchase any shares and the program may be terminated at any time. Under the prior program, approximately 10.6 million shares were repurchased on August 10, 2006 at an initial purchase price of $600 million, or $56.44 per share. The final purchase price under that program will be adjusted to reflect the ultimate cost to acquire the shares over a period of up to seven months ending March 2007. FirstEnergy is currently in negotiations with a major financial institution to enter into a new accelerated share repurchase program contingent among other things on amending its current accelerated share repurchase program to allow FirstEnergy to enter into the new accelerated repurchase program.

Generation

FirstEnergy's generating fleet produced a record 82.0 billion KWH during 2006 compared to 80.2 billion KWH in 2005. FirstEnergy's non-nuclear fleet produced a record 53.0 billion KWH, while its nuclear facilities produced 29.0 billion KWH.

Increased Generation Capacity – During 2006, generation capacity at several units in FirstEnergy's fleet increased as a result of work completed in connection with outages for refueling or other maintenance. These capacity additions were achieved in support of FirstEnergy's operating strategy to maximize its existing generation assets. The resulting increases in generating capacity are summarized below:

2006 Power Uprates (MW)	
Fossil:	
Bruce Mansfield Unit 2	50
Nuclear:	
Beaver Valley Unit 1	25
Beaver Valley Unit 2	10
Davis-Besse	14
	49
Total	99

Beaver Valley Power Station – On December 19, 2006, the NRC issued a NOV and a Confirmatory Order related to a June 1, 2005, incident in which a contract engineer at Beaver Valley signed off on an incomplete Engineering Change Package (ECP) related to the planned 2006 Beaver Valley Unit 1 reactor head replacement. The NRC's investigation concluded that the contractor deliberately violated FENOC's procedure; that FENOC quickly identified and resolved the incomplete ECP; and that FENOC implemented corrective actions to prevent a recurrence. The violation was classified as Level III, with no civil penalty.

New Coal Supply Agreement – On June 22, 2006, FGCO entered into a new coal supply agreement with CONSOL under which CONSOL will supply a total of more than 128 million tons of high-BTU coal to FirstEnergy for a 20-year period beginning in 2009. The new agreement will replace a coal supply agreement that took effect in 2003 and extended through 2020. Under the new agreement, CONSOL will increase its coal shipments by approximately 2 million tons per year.

Environmental Update – In June 2006, FirstEnergy finalized its air quality compliance strategy for 2006 through 2011. The program, which is currently expected to cost approximately $1.8 billion with the majority of those expenditures occurring between 2007 and 2009, is consistent with previous estimates and assumptions reflected in FirstEnergy's long-term financial planning for air and water quality and other environmental matters.

Wind Power Generation – In 2006, FirstEnergy entered into multi-year agreements to purchase a combined 284.5 MW of wind power output from three wind power generation projects. Two of the projects are being developed in Pennsylvania and the third is being developed in West Virginia. The projects are anticipated to be completed by the end of 2007. When combined with prior agreements, this brings the total wind power generation output under long-term contracts to 314.5 MW.

Rate Matters

Pennsylvania – On April 10, 2006 Met-Ed and Penelec made a comprehensive rate filing with the PPUC that addressed transmission, distribution and supply issues and requested annual rate increases of $216 million and $157 million, respectively. On January 11, 2007, the PPUC issued an order approving overall rate increases for Met-Ed of 5% ($59 million) and Penelec of 4.5% ($50 million). Based on the outcome of the rate filing, Met-Ed, Penelec and FES agreed to restate their partial requirements power sales agreement effective January 1, 2007. The restated agreement incorporates the same fixed price for energy and capacity supplied by FES as in prior arrangements and allows Met-Ed and Penelec to sell the output of their NUG generation into the market.

New Jersey – On December 6, 2006, the NJBPU approved a stipulation of settlement in its NUGC rate proceeding allowing JCP&L to recover $165 million of deferred costs over an 18-month period beginning on December 6, 2006. The costs were incurred by JCP&L during the period August 1, 2003 through December 31, 2005 to meet a portion of customers' generation needs with mandated NUG supply contracts. The approved stipulation increases JCP&L's cash flow, but is earnings neutral.

Ohio – On May 3, 2006, the Ohio Supreme Court affirmed the Ohio Companies' RSP for their customers, with respect to the rate stabilization charge, the shopping credits, the granting of interest on shopping credit incentive deferral amounts, and the Ohio Companies' financial separation plan. It remanded back to the PUCO the matter of ensuring the availability of sufficient means for customer participation in the competitive marketplace. On September 29, 2006, FirstEnergy's Ohio electric utility companies filed their proposal to establish a competitive bid process for market-based generation supply under which suppliers could submit prices to serve a portion of each Ohio Company's customer load. This proposal was in response to a July 26, 2006 PUCO directive to file plans for a competitive retail electric service option. If adopted, customers would have the opportunity to switch to alternative generation suppliers at prices established through the RFP program during 2007 and 2008.

Penn Power RFP – On October 19, 2006, the PPUC certified the RFP results for all customer classes reflecting the successful completion of the RFP bidding process. The RFP was conducted to secure Penn's PLR supply for the period January 1, 2007 through May 31, 2008 for those customers that do not choose alternative suppliers.

Financings

New Long-Term Debt Issuances – During 2006, several of FirstEnergy's subsidiaries issued new long-term debt. The proceeds from these transactions were primarily used to support FirstEnergy's financing strategy of obtaining more financial flexibility at the holding company and having more appropriate capital structures at the operating companies. The table below summarizes the new long-term debt issued in 2006, including the respective uses of proceeds:

Company	Principal (millions)	Maturity	Use of Proceeds
JCP&L	$200	2036	Fund maturing long-term debt
JCP&L*	182	2021	Preferred stock redemption; common stock repurchase; short-term debt reduction
OE	250	2016	Preferred stock redemption; common stock repurchase; short-term debt reduction
OE	350	2036	Preferred stock redemption; common stock repurchase; short-term debt reduction
TE	300	2037	Preferred stock redemption; common stock repurchase
CEI	300	2036	Common stock repurchase
FGCO	26	2041	Short-term debt reduction
	$1,608		

** Securitization bonds*

FirstEnergy Senior Note Retirement – On July 31, 2006, FirstEnergy redeemed $400 million of the $1 billion principal amount of its 5.5% Notes, Series A, in advance of the November 15, 2006 maturity date, with the remaining $600 million repaid at maturity.

Preferred Stock Redemptions – During the year, several of FirstEnergy's electric utilities redeemed all of their outstanding issues of preferred stock to reduce overall financing costs and improve financial flexibility: OE - $61 million, Penn - $14 million, TE - $96 million and JCP&L - $13 million. As a result of these redemptions, FirstEnergy's electric utility subsidiaries no longer have outstanding preferred stock.

Pollution Control Debt Transfers - In April and December 2006, approximately $1.1 billion of pollution control debt of OE, CEI, TE, and Penn was refinanced by FGCO and NGC. These transactions bring the total amount of the utilities' pollution control debt refinanced by the generation companies to approximately $1.4 billion, with approximately $700 million remaining to be transferred. These refinancings support the intra-system generation asset transfer that was completed in 2005.

Renewed and Upsized Credit Facility – On August 24, 2006, FirstEnergy and certain of its subsidiaries, including all of its operating utility subsidiaries, entered into a new five-year syndicated credit facility totaling $2.75 billion. The new facility replaced FirstEnergy's previous $2 billion credit facility and provides an average annual savings of 10 basis points on facility-related borrowing costs.

FIRSTENERGY'S BUSINESS

FirstEnergy is a public utility holding company headquartered in Akron, Ohio that operates primarily through two core business segments (see Results of Operations).

- **Regulated Services** transmits and distributes electricity through FirstEnergy's eight utility operating companies, serving 4.5 million customers within 36,100 square miles of Ohio, Pennsylvania and New Jersey. This business segment derives its revenue principally from the delivery of electricity generated or purchased by the Power Supply Management Services segment or, in some cases, purchased from independent suppliers in the states where the utility subsidiaries operate and transition cost recovery. The service areas of FirstEnergy's utilities are summarized below:

Company	Area Served	Customers Served
OE	Central and Northeastern Ohio	1,042,000
Penn	Western Pennsylvania	159,000
CEI	Northeastern Ohio	762,000
TE	Northwestern Ohio	314,000
JCP&L	Northern, Western and East Central New Jersey	1,082,000
Met-Ed	Eastern Pennsylvania	542,000
Penelec	Western Pennsylvania	589,000
ATSI	Service areas of OE, Penn, CEI and TE	

- **Power Supply Management Services** owns and operates FirstEnergy's power plants and purchases power to supply the electric power needs of customers in Ohio, Pennsylvania, Michigan, Maryland and New Jersey. Wholesale arrangements with FirstEnergy's Ohio and Pennsylvania utility subsidiaries provide the power to meet all or a portion of their PLR requirements. This segment also markets energy and energy-related products to deregulated wholesale and retail markets. The segment's net income is primarily derived from electric generation sales revenues less the related costs of electricity generation, including purchased power, and net transmission, congestion and ancillary costs charged by PJM and MISO to deliver energy to retail customers.

Other operating segments include HVAC services (divestiture completed in 2006) and telecommunication services. We have substantially completed the divestiture of our non-core businesses (see Note 16 to the consolidated financial statements). The assets and revenues for the other business operations are below the quantifiable threshold for separate disclosure as "reportable operating segments."

STRATEGY

We have targeted four objectives that reflect our strong focus on the fundamentals: improve operating performance, strengthen financial performance, enhance shareholder value; and ensure a safe work environment for employees. To achieve these goals, we are pursuing strategies that include successfully managing the transition to competitive generation markets; investing in our transmission and distribution infrastructure to enhance system reliability and customer service; reinvesting in our generating assets for cost-effective growth and environmental improvement; effectively managing commodity supplies and risks; and delivering consistent and predictable financial results.

Our success in these and other key areas will help us continue to achieve our vision of being a leading regional energy provider, recognized for operational excellence, customer service and our commitment to safety; the choice for long-term growth, investment value and financial strength; and a company driven by the leadership, skills, diversity and character of its employees.

RISKS AND CHALLENGES

In executing our strategy, we face a number of industry and enterprise risks and challenges, including:

- Risks arising from the reliability of our power plants and transmission and distribution equipment;
- Changes in commodity prices that could adversely affect our profit margins;
- We are exposed to operational, price and credit risks associated with selling and marketing products in the power markets that we do not always completely hedge against;
- Our risk management policies relating to energy and fuel prices, and counterparty credit are by their very nature risk related, and we could suffer economic losses despite such policies;
- Nuclear generation involves risks that include uncertainties relating to health and safety, additional capital costs, the adequacy of insurance coverage and nuclear plant decommissioning;
- We rely on transmission and distribution assets that we do not own or control to deliver our wholesale electricity. If transmission is disrupted including our own transmission, or not operated efficiently, or if capacity is inadequate, our ability to sell and deliver power may be hindered;
- Disruptions in our fuel supplies could occur, which could adversely affect our ability to operate our generation facilities;
- Seasonal temperature variations, as well as weather conditions or other natural disasters, could have a negative impact on our results of operations specifically with respect to our PLR contracts that do not provide for a specific level of supply, and demand significantly below or above our forecasts could adversely affect our energy margins;
- We are subject to financial performance risks related to the economic cycles of the electric utility industry;
- The goodwill of one or more of our operating subsidiaries may become impaired, which would result in write-offs of the impaired amounts;
- We face certain human resource risks associated with the availability of trained and qualified labor to meet our future staffing requirements;
- Significant increases in our operation and maintenance expenses, including our health care and pension costs, that could adversely affect our future earnings and liquidity;
- Acts of war or terrorism that could negatively impact our business;
- Complex and changing government regulations could have a negative impact on our results of operations;
- Regulatory changes in the electric industry including a reversal, discontinuance or delay of the present trend towards competitive markets could affect our competitive position and result in unrecoverable costs adversely affecting our business and results of operations;
- Our profitability is impacted by our affiliated companies' continued authorization to sell power at market-based rates;
- The amount we charge third parties for using our transmission facilities may be reduced and not recovered;
- There are uncertainties relating to our participation in the PJM and MISO regional transmission organizations;
- Costs of compliance with environmental laws are significant, and the cost of compliance with future environmental laws could adversely affect cash flow and profitability;
- We are and may become subject to legal claims arising from the presence of asbestos or other regulated substances at some of our facilities;
- The continuing availability and operation of generating units is dependent on retaining the necessary licenses, permits, and operating authority from governmental entities, including the NRC;
- We may ultimately incur liability in connection with federal proceedings;
- Interest rates and/or a credit ratings downgrade could negatively affect our financing costs and our ability to access capital;
- We must rely on cash from our subsidiaries; and
- We cannot assure common shareholders that future dividend payments will be made, or if made, in what amounts they may be paid.

FIRSTENERGY INTRA-SYSTEM GENERATION ASSET TRANSFERS

In 2005, the Ohio Companies and Penn entered into certain agreements implementing a series of intra-system generation asset transfers that were completed in the fourth quarter of 2005. The asset transfers resulted in the respective undivided ownership interests of the Ohio Companies and Penn in our nuclear and non-nuclear generation assets being owned by NGC and FGCO, respectively. The generating plant interests transferred do not include leasehold interests of CEI, OE and TE in certain of the plants that are currently subject to sale and leaseback arrangements with non-affiliates.

On October 24, 2005, the Ohio Companies and Penn completed the intra-system transfer of non-nuclear generation assets to FGCO. Prior to the transfer, FGCO, as lessee under a Master Facility Lease with the Ohio Companies and Penn, leased, operated and maintained the non-nuclear generation assets that it now owns. The asset transfers were consummated pursuant to FGCO's purchase option under the Master Facility Lease.

On December 16, 2005, the Ohio Companies and Penn completed the intra-system transfer of their respective ownership interests in the nuclear generation assets to NGC through, in the case of OE and Penn, an asset spin-off in the form of a dividend and, in the case of CEI and TE, a sale at net book value.

On December 28, 2006, the NRC approved the transfer of ownership in NGC from FirstEnergy to FES. Effective December 31, 2006, NGC is a wholly owned subsidiary of FES and second tier subsidiary of FirstEnergy. FENOC continues to operate and maintain the nuclear generation assets.

These transactions were undertaken pursuant to the Ohio Companies' and Penn's restructuring plans that were approved by the PUCO and the PPUC, respectively, under applicable Ohio and Pennsylvania electric utility restructuring legislation. Consistent with the restructuring plans, generation assets that had been owned by the Ohio Companies and Penn were required to be separated from the regulated delivery business of those companies through transfer or sale to a separate corporate entity. The transactions essentially completed the divestitures of owned assets contemplated by the restructuring plans by transferring the ownership interests to NGC and FGCO without impacting the operation of the plants. The transfers were intra-company transactions and, therefore, had no impact on our consolidated results.

RECLASSIFICATIONS

As discussed in Notes 1 and 16 to the consolidated financial statements, certain prior year amounts have been reclassified to conform to the current year presentation and to reflect certain businesses divested in 2006 that have been classified as discontinued operations (see Note 2(J)). These reclassifications did not change previously reported earnings for 2005 and 2004. All reclassifications have been evaluated and determined to be properly reflected as reclassifications in the respective period as presented in the Consolidated Statements of Income, Balance Sheets and Statements of Cash Flow.

RESULTS OF OPERATIONS

The financial results discussed below include revenues and expenses from transactions among our business segments. A reconciliation of segment financial results is provided in Note 16 to the consolidated financial statements. The divested FSG business segment is included in "Other and Reconciling Adjustments" due to its immaterial impact on current period financial results. Net income (loss) by major business segment was as follows:

	2006	2005	2004	Increase (Decrease) 2006 vs 2005	Increase (Decrease) 2005 vs 2004
	(In millions, except per share amounts)				
Net Income (Loss) By Business Segment:					
Regulated services	$ 932	$1,153	$1,047	$(221)	$ 106
Power supply management services	465	(50)	112	515	(162)
Other and reconciling adjustments*	(143)	(242)	(281)	99	39
Total	$1,254	$ 861	$ 878	$ 393	$ (17)
Basic Earnings Per Share:					
Income from continuing operations	$ 3.85	$ 2.68	$ 2.77	$1.17	$(0.09)
Discontinued operations	(0.01)	0.03	(0.09)	(0.04)	0.12
Cumulative effect of a change in accounting principle	–	(0.09)	–	0.09	(0.09)
Basic earnings per share	$ 3.84	$ 2.62	$ 2.68	$1.22	$(0.06)
Diluted Earnings Per Share:					
Income from continuing operations	$ 3.82	$ 2.67	$ 2.76	$1.15	$(0.09)
Discontinued operations	(0.01)	0.03	(0.09)	(0.04)	0.12
Cumulative effect of a change in accounting principle	–	(0.09)	–	0.09	(0.09)
Diluted earnings per share	$ 3.81	$ 2.61	$ 2.67	$1.20	$(0.06)

* *Represents other operating segments and reconciling items including interest expense on holding company debt, corporate support services revenues and expenses and the impact of the 2005 Ohio tax legislation.*

Summary of Results of Operations – 2006 Compared with 2005

Financial results for our major business segments in 2006 and 2005 were as follows:

2006 Financial Results	Regulated Services	Power Supply Management Services	Other and Reconciling Adjustments	FirstEnergy Consolidated
		(In millions)		
Revenues:				
External				
Electric	$3,850	$6,821	$ –	$10,671
Other	591	208	31	830
Internal	–	–	–	–
Total Revenues	4,441	7,029	31	11,501
Expenses:				
Fuel and purchased power	–	4,253	–	4,253
Other operating expenses	1,204	1,721	40	2,965
Provision for depreciation	376	194	26	596
Amortization of regulatory assets	842	19	–	861
Deferral of new regulatory assets	(217)	(283)	–	(500)
General taxes	532	171	17	720
Total Expenses	2,737	6,075	83	8,895
Operating Income (Loss)	1,704	954	(52)	2,606
Other Income (Expense):				
Investment income	270	36	(157)	149
Interest expense	(408)	(226)	(87)	(721)
Capitalized interest	14	11	1	26
Subsidiaries' preferred stock dividends	(16)	–	9	(7)
Total Other Expense	(140)	(179)	(234)	(553)
Income From Continuing Operations Before Income Taxes	1,564	775	(286)	2,053
Income taxes (benefit)	632	310	(147)	795
Income from continuing operations	932	465	(139)	1,258
Discontinued operations	–	–	(4)	(4)
Cumulative effect of a change in accounting principle	–	–	–	–
Net Income (Loss)	$ 932	$ 465	$(143)	$ 1,254

2005 Financial Results	Regulated Services	Power Supply Management Services	Other and Reconciling Adjustments	FirstEnergy Consolidated
		(In millions)		
Revenues:				
External				
Electric	$4,582	$5,964	$ –	$10,546
Other	573	103	136	812
Internal	270	–	(270)	–
Total Revenues	5,425	6,067	(134)	11,358
Expenses:				
Fuel and purchased power	–	4,011	–	4,011
Other operating expenses	1,250	1,986	(133)	3,103
Provision for depreciation	516	45	27	588
Amortization of regulatory assets	1,281	–	–	1,281
Deferral of new regulatory assets	(314)	(91)	–	(405)
General taxes	562	131	20	713
Total Expenses	3,295	6,082	(86)	9,291
Operating Income (Loss)	2,130	(15)	(48)	2,067
Other Income (Expense):				
Investment income	217	–	–	217
Interest expense	(392)	(55)	(213)	(660)
Capitalized interest	18	1	–	19
Subsidiaries' preferred stock dividends	(15)	–	–	(15)
Total Other Expense	(172)	(54)	(213)	(439)
Income From Continuing Operations Before Income Taxes	1,958	(69)	(261)	1,628
Income taxes (benefit)	784	(28)	(7)	749
Income from continuing operations	1,174	(41)	(254)	879
Discontinued operations	–	–	12	12
Cumulative effect of a change in accounting principle	(21)	(9)	–	(30)
Net Income (Loss)	$1,153	$ (50)	$(242)	$ 861

Changes Between 2006 and 2005 Financial Results – Increase (Decrease)	Regulated Services	Power Supply Management Services	Other and Reconciling Adjustments	FirstEnergy Consolidated
		(In millions)		
Revenues:				
External				
Electric	$(732)	$857	$ –	$125
Other	18	105	(105)	18
Internal	(270)	–	270	–
Total Revenues	(984)	962	165	143
Expenses:				
Fuel and purchased power	–	242	–	242
Other operating expenses	(46)	(265)	173	(138)
Provision for depreciation	(140)	149	(1)	8
Amortization of regulatory assets	(439)	19	–	(420)
Deferral of new regulatory assets	97	(192)	–	(95)
General taxes	(30)	40	(3)	7
Total Expenses	(558)	(7)	169	(396)
Operating Income	(426)	969	(4)	539
Other Income (Expense):				
Investment income	53	36	(157)	(68)
Interest expense	(16)	(171)	126	(61)
Capitalized interest	(4)	10	1	7
Subsidiaries' preferred stock dividends	(1)	–	9	8
Total Other Income (Expense)	32	(125)	(21)	(114)
Income From Continuing Operations Before Income Taxes	(394)	844	(25)	425
Income taxes (benefit)	(152)	338	(140)	46
Income from continuing operations	(242)	506	115	379
Discontinued operations	–	–	(16)	(16)
Cumulative effect of a change in accounting principle	21	9	–	30
Net Income	$(221)	$515	$ 99	$393

Regulated Services – 2006 Compared with 2005

Net income decreased $221 million (19%) to $932 million in 2006 compared to $1.153 billion in 2005, primarily due to decreased operating revenues partially offset by lower operating expenses.

Revenues –

The decrease in total revenues by service type is summarized below:

Revenues By Type of Service	2006	2005	Increase (Decrease)
		(In millions)	
Distribution services	$3,850	$4,582	$(732)
Transmission services	389	415	(26)
Internal lease revenues	–	270	(270)
Other	202	158	44
Total Revenues	$4,441	$5,425	$(984)

Decreases in distribution deliveries by customer class are summarized in the following table:

Electric Distribution Deliveries	
Residential	(3.9)%
Commercial	(1.4)%
Industrial	(1.4)%
Total Distribution Deliveries	(2.3)%

The completion of our Ohio Companies' and Penn's generation transition cost recovery under their respective transition plans in 2005 were the primary reasons for lower distribution unit prices, which, in conjunction with lower KWH deliveries, resulted in lower distribution delivery revenues. The decreases in deliveries to customers were primarily due to milder weather during 2006 as compared to 2005. The following table summarizes major factors contributing to the $732 million decrease in distribution service revenues in 2006 compared to 2005:

Sources of Change in Distribution Revenues	Increase (Decrease)
	(In millions)
Changes in customer usage	$(221)
Ohio shopping incentives	222
Reduced Ohio transition rates	(817)
Other	84
Net Decrease in Distribution Revenues	$(732)

The decrease in internal lease revenues reflected the effect of the 2005 generation asset transfers discussed above. The 2005 generation assets lease revenue from affiliates ceased as a result of the transfers. The increase in other revenues is due to higher payments received during the first quarter of 2006 under a contract provision associated with the prior sale of TMI-1, a 2006 uranium enrichment settlement and increased income from life insurance investments.

Expenses –

The decrease in revenues discussed above was partially offset by a $558 million decrease in total expenses.

- Other operating expenses were $46 million lower in 2006 due, in part, to the following factors:
  - The absence in 2006 of expenses for ancillary service refunds to third parties of $27 million in 2005 associated with implementation of the Ohio Companies' RCP in 2006 (under which alternate suppliers of ancillary services now bill customers directly for those services);
  - A $52 million decrease in employee and contractor costs resulting from lower storm-related expenses, reduced employee benefit costs and the decreased use of outside contractors for tree trimming, reliability work, legal services and jobbing and contracting; and
  - A $31 million increase in other expenses principally due to increased corporate support services of $18.5 million, and to the absence in 2006 of a $6 million insurance premium credit and an $8.6 million insurance settlement received in 2005.
- Lower depreciation expense of $140 million resulted principally from the generation asset transfers;
- Reduced amortization of regulatory assets of $439 million resulted from the completion of Ohio generation transition cost recovery and Penn's transition plan in 2005;
- A $97 million decrease in deferral of new regulatory assets due to a 2005 rate decision for JCP&L and the end of shopping incentive deferrals under the Ohio Companies' transition plan partially offset by the distribution cost deferrals authorized under the Ohio Companies' RCP; and
- General taxes decreased by $30 million primarily due to lower property taxes as a result of the generation asset transfers.

Other Income and Expense –

- Higher investment income reflects the impact of the generation asset transfers. Interest income on the affiliated company notes receivable from the power supply management services segment in 2006 is partially offset by the absence of nuclear decommissioning trust investments, the majority of which is now included in the power supply management services segment; and
- Interest expense increased by $16 million due to the Ohio Companies' 2006 long-term debt issuances. As further discussed under Capital Resources and Liquidity, the Ohio Companies used the debt proceeds to repurchase portions of their respective common stock from FirstEnergy, where the proceeds were used for the retirement of FirstEnergy notes maturing in 2006.

Power Supply Management Services – 2006 Compared with 2005

Net income for this segment was $465 million in 2006 compared to a net loss of $50 million in 2005. Substantial improvement in the gross generation margin and increased transmission and fuel cost deferrals were partially offset by higher depreciation, general taxes and interest expense resulting from the generation asset transfers.

Revenues –

Electric generation sales revenues increased $763 million in 2006 compared to 2005. This increase primarily resulted from a 6.7% increase in retail KWH sales due principally to the return of customers as a result of third-party suppliers leaving the northern Ohio marketplace, and higher unit prices resulting from implementation in 2006 of the rate stabilization and fuel recovery charges under the Ohio companies' RCP. The higher retail sales reduced energy available for sale to the wholesale market. Increased transmission revenues reflected new revenues of approximately $117 million under a new MISO transmission rider that began in 2006. These increases were partially offset by a reduction in wholesale sales revenue as a result of both lower KWH sales and lower unit prices.

The increase in reported segment revenues resulted from the following sources:

Revenues By Type of Service	2006	2005	Increase (Decrease)
		(In millions)	
Electric Generation Sales:			
Retail	$5,459	$4,219	$1,240
Wholesale	935	1,412	(477)
Total Electric Generation Sales	6,394	5,631	763
Transmission	572	403	169
Other	63	33	30
Total Revenues	$7,029	$6,067	$ 962

The following table summarizes the price and volume factors contributing to changes in sales revenues from retail and wholesale customers:

Sources of Change in Electric Generation Sales	Increase (Decrease)
	(In millions)
Retail:	
Effect of 6.7% increase in customer usage	$ 285
Change in prices	955
	1,240
Wholesale:	
Effect of 19.1% decrease in KWH sales	(270)
Change in prices	(207)
	(477)
Net Increase in Electric Generation Sales	$ 763

Expenses –

Total operating expenses decreased by $7 million. The decrease was due to the following factors:

- Lower non-fuel operating expenses of $265 million, which reflected the absence in 2006 of generating asset lease rents of $270 million charged in 2005 due to the generation asset transfers, lower transmission expenses compared to 2005, and credits from the sale of emission allowances. Also absent in 2006 were the 2005 accruals of $8.5 million for a civil penalty, $10 million for obligations to fund environmentally beneficial projects in connection with the Sammis Plant New Source Review settlement, and $31.5 million for a civil penalty related to the Davis-Besse outage; and

- An increase of $192 million in the deferral of new regulatory assets, which consisted of PJM/MISO costs incurred that will be recovered from customers through future rates ($79 million) and the Ohio RCP fuel deferral and related interest ($113 million).

The above decreases in expenses were partially offset by:

- Higher fuel and purchased power costs of $242 million, including increased fuel costs of $94 million caused by our generation fleet's record output of 82.0 billion KWH. In particular, coal costs increased $128 million as a result of increased generation output, higher coal prices and increased transportation costs for western coal. The increased coal costs were partially offset by lower natural gas and emission allowance costs of $42 million. Purchased power costs increased $148 million due to higher prices partially offset by lower volumes. Factors contributing to the higher costs are summarized in the following table:

Sources of Change in Fuel and Purchased Power	Increase (Decrease)
	(In millions)
Fuel:	
Change due to increased unit costs	$ 70
Change due to volume consumed	24
	94
Purchased Power:	
Change due to increased unit costs	206
Change due to volume purchased	(33)
PPUC NUG adjustment applicable to prior year	10
Increase in NUG costs deferred	(35)
	148
Net Increase in Fuel and Purchased Power Costs	$242

- An increase in nuclear operating expenses of $55 million due to three refueling outages in 2006 compared with two refueling outages in 2005;
- Increased depreciation expenses of $149 million, resulting principally from the generation asset transfers; and
- Higher general taxes of $40 million due principally to additional property taxes resulting from the generation asset transfers.

Other Income and Expense –

- Investment income in 2006 was $36 million higher primarily due to nuclear decommissioning trust investments acquired through the generation asset transfers; and
- Interest expense increased by $171 million, primarily due to interest on the associated company notes payable that financed the generation asset transfers.

Other – 2006 Compared to 2005

FirstEnergy's financial results from other operating segments and reconciling items, including interest expense on holding company debt and corporate support services revenues and expenses, resulted in a $99 million increase to FirstEnergy's net income in 2006 compared to 2005. The increase was primarily due to the absence of 2005 income tax expenses of $63 million consisting of the write-off of income tax benefits of $51 million due to the 2005 change in Ohio tax legislation and $12 million due to a 2005 JCP&L tax audit adjustment; $23 million of 2006 income tax benefits, primarily reflecting the 2005 federal income tax return filed in the third quarter of 2006 and the Ohio tax benefit related to a voluntary $300 million pension plan contribution (see Note 3); a $3 million gain related to interest rate swap financing arrangements and a $14 million increase in investment income in 2006. These increases were partially offset by financing redemption charges of $16 million in 2006, a $5 million decrease in gas commodity transaction results and the absence of 2005 non-core assets sale net gains of $9 million. The following table summarizes the sources of income from discontinued operations (in millions) for 2006 and 2005:

Discontinued Operations (Net of tax)	2006	2005
Gain on sale:		
Natural gas business	$ –	$ 5
FSG Subsidiaries	2	12
Reclassification of operating income	(6)	(5)
Total	$(4)	$12

Summary of Results of Operations – 2005 Compared with 2004

Financial results for our reportable major business segments in 2004 were as follows:

2004 Financial Results	Regulated Services	Power Supply Management Services	Other and Reconciling Adjustments	FirstEnergy Consolidated
		(In millions)		
Revenues:				
External				
Electric	$4,396	$6,435	$ –	$10,831
Other	489	75	205	769
Internal	318	–	(318)	–
Total Revenues	5,203	6,510	(113)	11,600
Expenses:				
Fuel and purchased power	–	4,469	–	4,469
Other operating expenses	1,340	1,660	(90)	2,910
Provision for depreciation	513	35	37	585
Amortization of regulatory assets	1,166	–	–	1,166
Deferral of new regulatory assets	(257)	–	–	(257)
General taxes	538	122	18	678
Total Expenses	3,300	6,286	(35)	9,551
Operating Income (Loss)	1,903	224	(78)	2,049
Other Income (Expense):				
Investment income	205	–	–	205
Interest expense	(361)	(43)	(267)	(671)
Capitalized interest	19	6	1	26
Subsidiaries' preferred stock dividends	(21)	–	–	(21)
Total Other Income (Expense)	(158)	(37)	(266)	(461)
Income From Continuing Operations Before Income Taxes	1,745	187	(344)	1,588
Income taxes (benefit)	698	75	(92)	681
Income from continuing operations	1,047	112	(252)	907
Discontinued operations	–	–	(29)	(29)
Cumulative effect of a change in accounting principle	–	–	–	–
Net Income (Loss)	$1,047	$ 112	$(281)	$ 878

Changes Between 2005 and 2004 Financial Results – Increase (Decrease)	Regulated Services	Power Supply Management Services	Other and Reconciling Adjustments[1]	FirstEnergy Consolidated
	(In millions)			
Revenues:				
External				
Electric	$186	$(471)	$ –	$(285)
Other	84	28	(69)	43
Internal	(48)	–	48	–
Total Revenues	222	(443)	(21)	(242)
Expenses:				
Fuel and purchased power	–	(458)	–	(458)
Other operating expenses	(90)	326	(43)	193
Provision for depreciation	3	10	(10)	3
Amortization of regulatory assets	115	–	–	115
Deferral of new regulatory assets	(57)	(91)	–	(148)
General taxes	24	9	2	35
Total Expenses	(5)	(204)	(51)	(260)
Operating Income	227	(239)	30	18
Other Income (Expense):				
Investment income	12	–	–	12
Interest expense	(31)	(12)	54	11
Capitalized interest	(1)	(5)	(1)	(7)
Subsidiaries' preferred stock dividends	6	–	–	6
Total Other Income (Expense)	(14)	(17)	53	22
Income From Continuing Operations Before Income Taxes	213	(256)	83	40
Income taxes	86	(103)	85	68
Income from continuing operations	127	(153)	(2)	(28)
Discontinued operations	–	–	41	41
Cumulative effect of a change in accounting principle	(21)	(9)	–	(30)
Net Income	$106	$(162)	$ 39	$ (17)

(1) *The impact of the new Ohio tax legislation is included with our other operating segments and reconciling adjustments.*

Regulated Services – 2005 Compared with 2004

Net income increased by $106 million to $1.15 billion, a 10.1% increase in 2005, compared to $1.05 billion in 2004, primarily as a result of increased sales to customers.

Revenues –

Total revenues increased by $222 million in 2005 compared to 2004, resulting from the following sources:

Revenues By Type of Service	2005	2004	Increase (Decrease)
	(In millions)		
Distribution services	$4,582	$4,396	$186
Transmission services	415	333	82
Internal lease revenues	270	318	(48)
Other	158	156	2
Total Revenues	$5,425	$5,203	$222

Increases in distribution deliveries by customer class are summarized in the following table:

Electric Distribution Deliveries	
Residential	7.3%
Commercial	4.8
Industrial	2.0
Total Distribution Deliveries	4.7%

Increased consumption offset in part by lower composite prices to customers resulted in higher distribution delivery revenue. The following table summarizes major factors contributing to the $186 million increase in distribution service revenue in 2005:

Sources of Change in Distribution Revenues	Increase (Decrease)
	(In millions)
Changes in customer usage	$264
Changes in prices:	
Rate changes –	
Ohio shopping credit incentives	(44)
JCP&L rate settlements	48
Billing component reallocations	(82)
Net Increase in Distribution Revenues	$186

Distribution revenues benefited from unseasonably warmer summer temperatures in 2005, compared to 2004, which increased air-conditioning loads of residential and commercial customers. While industrial deliveries also increased, that impact was more than offset by lower unit prices in that sector. Higher base rates from JCP&L's stipulated rate settlements were more than offset by additional credits provided to customers under the Ohio transition plan who shop for electricity from suppliers other than their local utility. Reallocation of billing components between distribution and generation for certain Ohio industrial customers with special contracts also offset the higher base rates. Shopping credit incentives do not affect current period earnings due to deferral of the incentives for future recovery from customers.

Transmission revenues increased $82 million in 2005 from 2004 due in part to increased loads resulting from warmer summer weather and higher transmission usage prices. Lease revenue from affiliates decreased $48 million due to the intra-system generation asset transfers discussed above.

Expenses –

Total operating expenses decreased by $5 million in 2005 compared to the prior year, which reflected lower other operating expenses due, in part, to lower regulation management expenses, employee benefit costs and additional deferrals of regulatory assets of $57 million, primarily due to shopping incentive credits and related interest on these deferrals.

Partially offsetting these lower costs were the following factors:

- Additional amortization of regulatory assets of $115 million, principally Ohio transition costs, due primarily to using the interest method to amortize transition costs; and
- General taxes increased by $24 million due to higher property taxes and increased KWH deliveries which increased the Ohio KWH tax and the Pennsylvania gross receipts tax.

Other Income –

Total other income (expense) decreased by $14 million in 2005 compared to 2004 due to the net effect of the following:

- Investment income increased approximately $12 million in 2005 due primarily to realized gains on nuclear decommissioning trust investments; and
- Interest expense was $31 million higher in 2005.

Power Supply Management Services – 2005 Compared with 2004

Net income for this segment decreased $162 million resulting in a net loss of $50 million for 2005 compared to net income of $112 million in 2004. Lower generation gross margin, higher nuclear operating costs and amounts recognized for fines, penalties and obligations associated with the proceedings involving the W.H. Sammis Plant and the Davis-Besse Nuclear Power Station contributed to the decrease in net income in 2005 when compared to 2004.

Revenues –

A decrease in wholesale electric revenues and purchased power costs in 2005 compared to the prior year primarily resulted from FES recording PJM sales and purchased power transactions on an hourly net position basis beginning in the first quarter of 2005 compared with recording each discrete transaction (on a gross basis) in 2004 (see PJM INTERCONNECTION TRANSACTIONS discussed later). This change had no impact on earnings and resulted from the dedication of the generation output of the Beaver Valley Power Station to PJM in January 2005. Wholesale electric revenues and purchased power costs in 2004 were each $1.1 billion higher due to recording those transactions on a gross basis.

Excluding the effect of the change in recording PJM wholesale transactions on a gross basis in 2004 ($1.1 billion), electric generation revenues increased $569 million in 2005 compared to 2004 primarily resulting from a 3.5% increase in KWH sales from higher retail customer usage and a 14% average increase in unit prices in the wholesale market. The increase in retail sales reduced energy available for sale to the wholesale market, resulting in a 2% reduction in wholesale sales (before the PJM adjustment). Transmission revenues increased $59 million in 2005 compared to 2004 due primarily to higher transmission system usage.

The change in reported revenues resulted from the following:

Revenues By Type of Service	2005	2004	Increase (Decrease)
		(In millions)	
Electric generation sales:			
Retail	$4,219	$3,795	$424
Wholesale[1]	1,412	1,267	145
Total electric generation sales	5,631	5,062	569
Transmission	403	344	59
Other	33	36	(3)
	6,067	5,442	625
PJM adjustment	–	1,068	(1,068)
Total Revenues	$6,067	$6,510	$(443)

[1] Excluding 2004 effect of recording PJM transactions on a gross basis.

The following table summarizes the price and volume factors contributing to increased sales revenue from retail and wholesale customers:

Sources of Change in Electric Generation Sales	Increase (Decrease)
	(In millions)
Retail:	
Effect of 5.2% increase in customer usage	$228
Change in prices	196
	424
Wholesale:	
Effect of 2.3% reduction in customer usage[1]	(28)
Change in prices	173
	145
Net Increase in Electric Generation Sales	$569

[1] Decrease of 46.5% including the effect of the PJM adjustment.

Expenses –

Excluding the effect of the $1.1 billion of PJM purchased power costs recorded on a gross basis in 2004, total operating expenses increased by $864 million in 2005 compared to 2004. Higher fuel and purchased power costs contributed $610 million of the increase, resulting from higher fuel costs of $308 million and increased purchased power costs of $302 million. Factors contributing to the higher costs are summarized in the following table:

Sources of Change in Fuel and Purchased Power	Increase (Decrease)
	(In millions)
Fuel:	
Change due to increased unit costs	$ 254
Change due to volume consumed	54
	308
Purchased Power:	
Change due to increased unit costs	360
Change due to volume purchased	(55)
Increase in costs deferred	(3)
	302
Total Increase	610
PJM adjustment	(1,068)
Net Decrease in Fuel and Purchased Power Costs	$(458)

Our generation fleet established a record output of 80.2 billion KWH in 2005. As a result, increased coal consumption and the related cost of emission allowances combined to increase fossil fuel expense. Higher coal costs resulted from increased market purchases, higher contract coal prices and increased transportation costs. Emission allowance costs increased primarily from higher prices. To a lesser extent, fuel expense increased due to higher costs associated with the increase in generation from the fossil units relative to nuclear generation. Fossil generation output increased 11% in 2005 and nuclear output decreased by 4%, compared to 2004, due to the nuclear refueling outages discussed below.

Other operating costs increased $326 million in 2005 compared to 2004. Non-fuel nuclear costs were higher in 2005 due to increased transmission costs and refueling outages at Perry Unit1 (including an unplanned extension) and Beaver Valley

Unit2 and a scheduled 23-day mid-cycle inspection outage at the Davis-Besse Plant. There was only one refueling outage in 2004. Fines and penalties related to the Davis-Besse reactor head issue (approximately $31.5 million) and the EPA settlement related to the W.H. Sammis Plant ($18.5 million) also contributed to the higher costs. Higher transmission costs of $303 million due primarily to increased loads and higher transmission system usage charges further increased other operating costs in 2005. The higher costs in 2005 were partially offset by lower fossil generation costs that resulted primarily from emission allowance transactions and reduced maintenance outages in 2005. Also offsetting the cost increases were lower intersegment lease expenses due to the intra-system generation asset transfer and the PUCO-approved deferral of MISO transmission costs.

Income taxes –

Income taxes decreased as a result of lower taxable income, partially offset by the impact of the $28 million penalty related to the Davis-Besse reactor head issue that was not deductible for income tax purposes.

Other – 2005 Compared with 2004

FirstEnergy's financial results from other operating segments and reconciling adjustments, including interest expense on holding company debt, corporate support services revenues and expenses and the impacts of the new Ohio tax legislation (discussed below) all contributed to a $39 million increase in net income compared to 2004. The increase was partially due to the absence in 2005 of goodwill impairments at FSG of $26 million (included in discontinued operations in 2004) and the 2004 class action lawsuit settlement as well as gains on the sale of assets ($17 million) in 2005 compared to net losses on the sale of assets ($6 million) in 2004, partially offset by a goodwill impairment at MYR of $9 million (included in discontinued operations in 2005) not present in 2004.

On June 30, 2005, tax legislation was enacted in the State of Ohio that created a new CAT tax, which is based on qualifying "taxable gross receipts" that does not consider any expenses or costs incurred to generate such receipts, except for items such as cash discounts, returns and allowances, and bad debts. The CAT tax was effective July 1, 2005, and replaces the Ohio income-based franchise tax and the Ohio personal property tax. The CAT tax is phased-in while the current income-based franchise tax is phased-out over a five-year period at a rate of 20% annually, beginning with the year ended 2005, and the personal property tax is phased-out over a four-year period at a rate of approximately 25% annually, beginning with the year ended 2005. During the phase-out period the Ohio income-based franchise tax was or will be computed consistent with the prior law, except that the tax liability as computed will be multiplied by 80% in 2005; 60% in 2006; 40% in 2007 and 20% in 2008 to determine the actual liability, thereby eliminating the current income-based franchise tax over a five-year period. As a result of the new tax structure, all net deferred tax benefits that are not expected to reverse during the five-year phase-in period were written off as of June 30, 2005. The impact on income taxes associated with the required adjustment to net deferred taxes for 2005 was an additional tax expense of approximately $52 million, which was partially offset by the initial phase-out of the Ohio income-based franchise tax, which reduced income taxes by approximately $6 million in 2005. See Note 9 to the Consolidated Financial Statements.

CUMULATIVE EFFECT OF ACCOUNTING CHANGE

Results in 2005 included an after-tax charge of $30 million recorded upon the adoption of FIN 47 in December 2005. We identified applicable legal obligations as defined under FIN 47 at our active and retired generating units and retired plants (retained by the regulated utilities), substation control rooms, service center buildings, line shops and office buildings, identifying asbestos as the primary conditional ARO. We recorded a conditional ARO liability of $57 million (including accumulated accretion for the period from the date the liability was incurred to the date of adoption), an asset retirement cost of $16 million (recorded as part of the carrying amount of the related long-lived asset), and accumulated depreciation of $12 million. We charged regulatory liabilities for $5 million upon adoption of FIN47 for the transition amounts related to establishing the ARO for asbestos removal from substation control rooms and service center buildings for OE, Penn, CEI, TE and JCP&L. The remaining cumulative effect adjustment for unrecognized depreciation and accretion of $48 million was charged to income ($30 million, net of tax), or $0.09 per share of common stock for the year ended December 31, 2005. (See Note 12.)

DISCONTINUED OPERATIONS

Discontinued operations for 2006 include the remaining FSG subsidiaries (Hattenbach, Dunbar, Edwards, and RPC), and a portion of MYR. FirstEnergy sold 60% of MYR in March 2006 and began accounting for its remaining interest in MYR under the equity method. An additional 1.67% was sold in June 2006 and the remaining 38.33% was sold in November 2006. MYR's results prior to the sale of the initial 60% in March 2006 and the gain on the March sale is included in discontinued operations. The 2006 MYR results, subsequent to the March 2006 sale, recorded as equity investment income by FirstEnergy, and the gain on the November sale are included in income from continuing operations.

The following table summarizes the sources of income (loss) from discontinued operations:

Discontinued Operations (net of tax)	2006	2005	2004
		(In millions)	
FES natural gas business – gain on sale	$ –	$ 5	$ –
FSG subsidiaries – gain on sale	2	12	–
Net gain on divestitures	2	17	–
Reclassification of operating (loss) income to discontinued operations:			
FES natural gas business	–	–	4
FSG subsidiaries	(8)	(4)	(29)
MYR	2	(1)	(4)
Income (Loss) from discontinued operations	$(4)	$12	$(29)

POSTRETIREMENT BENEFITS

Strengthened equity markets, as well as $500 million voluntary cash pension contributions made in both 2005 and 2004, contributed to reductions of $27 million and $66 million in postretirement benefits expenses in 2006 and 2005, respectively, from the prior year. The following table reflects the portion of postretirement costs that were charged to expense in 2006, 2005 and 2004:

Postretirement Benefits Expenses	2006	2005	2004
		(In millions)	
Pension	$29	$ 32	$ 83
OPEB	48	72	87
Total	$77	$104	$170

Pension and OPEB expenses are included in various cost categories and have contributed to cost decreases discussed above for 2006. We made an additional contribution of $300 million on January 2, 2007 that is expected to result in further reduced pension costs in 2007. In 2008, we will increase the share of coinsurance, as well as increase the health care premiums paid by certain retirees, which is expected to significantly reduce OPEB costs in 2007. 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 subsidiaries are obligated to provide generation service with an estimated power demand of 134.5 billion KWH in 2007. These obligations arise from customers who have elected to continue to receive generation service from our utility subsidiaries under regulated retail tariffs and from customers who have selected FES as their alternate generation provider. Geographically, approximately 50% of the total generation service obligation is for customers located in the MISO market area and 50% for customers located in the PJM market area.

Within the franchise territories of our utility subsidiaries, alternative energy suppliers currently provide generation service for approximately 60MW (summer peak) of load with an estimated energy requirement of 500 million KWH. If these alternate suppliers fail to deliver power to their customers located in one of our utility subsidiaries' service area, the utility subsidiary must procure replacement power in the role of PLR (see Note 10 for a discussion of the auction of JCP&L's PLR obligation). JCP&L's costs for any replacement power would be recovered under NJBPU rules.

To meet these generation service obligations, our subsidiaries have access, either through ownership or lease, to 14,041 MW of installed generating capacity, which for 2007 is expected to provide approximately 60% of the required power supply. The balance has been secured through a combination of long-term purchases (contract term of greater than one year) and short-term purchases (contract of term of less than one year). Additional power supply requirements will be met through spot market transactions.

PJM AND MISO INTERCONNECTION TRANSACTIONS

FES engages in purchase and sale transactions in the PJM market to support the supply of end-use customers, including PLR requirements in Pennsylvania. In conjunction with our dedication of the Beaver Valley Plant to PJM on January 1, 2005, FES began accounting for purchase and sale transactions in the PJM market based on its net hourly position – recording each hour as either an energy purchase or an energy sale in the Consolidated Statements of Income relating to the Power Supply Management Services segment. Hourly energy positions are aggregated to recognize gross purchases and sales for the month. This revised method of accounting, which has no impact on net income, is consistent with the practice of other energy companies that have dedicated generating capacity in PJM and correlates with PJM's scheduling and reporting of hourly energy transactions. FES also applies the net hourly methodology to purchase and sale transactions in MISO's energy market, which became active on April 1, 2005.

CAPITAL RESOURCES AND LIQUIDITY

Our business is capital intensive and requires considerable capital resources to fund operating expenses, construction expenditures, scheduled debt maturities and interest and dividend payments. Our cash requirements in 2006 for these items were met without significantly increasing our net debt. In 2007 and subsequent years, we expect to meet our contractual obligations and other cash requirements primarily with a combination of cash from operations and funds from the capital markets. We also expect that borrowing capacity under credit facilities will continue to be available to manage working capital requirements during those periods.

Changes in Cash Position

Our primary source of cash required for continuing operations as a holding company is cash from the operations of our subsidiaries. We also have access to $2.75 billion of short-term financing under a revolving credit facility which expires in 2011, subject to short-term debt limitations under current regulatory approvals of $1.5 billion and to outstanding borrowings by our subsidiaries that are also parties to such facility. With the exception of Met-Ed, which is currently in an accumulated deficit position, there are no material restrictions on the payment of cash dividends by our subsidiaries.

In 2006, FirstEnergy redeemed $400 million of the $1 billion principal amount of its 5.5% Notes, Series A, in advance of the November 15, 2006 maturity date, with the remaining $600 million repaid at maturity using cash proceeds from the Ohio Companies' repurchases of their respective common stock from FirstEnergy (OE - $500 million, CEI - $300 million and TE - $225 million).

On August 10, 2006, FirstEnergy repurchased 10.6 million shares, or approximately 3.2%, of its outstanding common stock at an initial purchase price of $600 million, pursuant to an accelerated share repurchase program. The repurchase was funded with borrowings from FirstEnergy's revolving credit facility.

As of December 31, 2006, we had $90 million of cash and cash equivalents compared with $64 million as of December 31, 2005. The major sources for changes in these balances are summarized below.

Cash Flows From Operating Activities

Net cash provided from operating activities was $1.9 billion in 2006, $2.2 billion in 2005 and $1.9 billion in 2004, summarized as follows:

Operating Cash Flows	2006	2005	2004
		(In millions)	
Net income	$1,254	$ 861	$ 878
Non-cash charges (credits)	770	1,324	1,326
Pension trust contribution*	90	(341)	(300)
Working capital and other	(175)	376	(12)
Net cash provided from operating activities	$1,939	$2,220	$1,892

** Pension trust contributions in 2005 and 2004 are net of $159 million and $200 million of related current year cash income tax benefits, respectively. The $90 million cash inflow in 2006 represents reduced income taxes paid in 2006 relating to a January 2007 pension contribution.*

Net cash provided from operating activities decreased by $281 million in 2006 compared to 2005 primarily due to a $551 million decrease from working capital and a $554 million decrease in non-cash charges. These decreases were partially offset by the tax benefit in 2006 relating to the January 2007 pension contribution and the absence in 2006 of the pension trust contribution in 2005 and higher net income in 2006 compared to 2005 (see Results of Operations). The decrease from working capital changes primarily resulted from the absence of $242 million of funds received in 2005 for prepaid electric service (under a three-year Energy for Education Program with the Ohio Schools Council), increased tax payments of $325 million, and $273 million of cash collateral returned to suppliers. These decreases were partially offset by an increase in working capital from the collection of receivables of $192 million, reflecting increased electric sales revenues.

Net cash provided from operating activities increased $328 million in 2005 compared to 2004 primarily due to a $388 million increase from changes in working capital and a $2 million decrease in non-cash charges. In 2005 and 2004, we made voluntary after-tax pension trust contributions of $341 million and $300 million, respectively. The increase from working capital resulted from increased returned cash collateral of $259 million, decreased outflow of $143 million for payables and $242 million of funds received in 2005 for prepaid electric service as discussed above. These increases were partially offset by decreases in cash provided from the collection of receivables of $241 million and the absence of a $53 million NUG power contract restructuring transaction in 2005.

Cash Flows From Financing Activities

In 2006, 2005 and 2004, net cash used for financing activities was $804 million, $876 million and $1.5 billion, respectively, primarily reflecting the redemptions of debt and preferred stock shown below:

Securities Issued or Redeemed	2006	2005	2004
		(In millions)	
New Issues			
Pollution control notes	$1,157	$ 721	$ 261
Senior secured notes	382	–	300
Unsecured notes	1,200	–	400
	$2,739	$ 721	$ 961
Redemptions			
First mortgage bonds	$ 41	$ 252	$ 589
Pollution control notes	1,189	555	80
Senior secured notes	206	94	471
Long-term revolving credit	–	215	95
Unsecured notes	1,100	308	337
Common stock	600	–	–
Preferred stock	193	170	2
	$3,329	$1,594	$1,574
Short-term borrowings (repayments), net	$ 386	$ 561	$ (351)

FirstEnergy had approximately $1.1 billion of short-term indebtedness as of December 31, 2006 compared to approximately $731 million as of December 31, 2005. This increase primarily reflects FirstEnergy's use of short-term debt to fund its $600 million common share repurchase in August 2006. Available bank borrowing capability (in millions) as of December 31, 2006 included the following:

Borrowing Capability	
Short-term credit facilities[1]	$2,870
Accounts receivable financing facilities	550
Utilized	(1,105)
LOCs	(478)
Net	$1,837

[1] *Includes the $2.75 billion revolving credit facility described below, a $100 million revolving credit facility that expires in December 2009 and a $20 million uncommitted line of credit facility.*

As of December 31, 2006, the Ohio Companies and Penn had the aggregate capability to issue approximately $2.8 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, CEI and TE is 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, CEI and TE to incur additional secured debt not otherwise permitted by a specified exception of up to $543 million, $491 million and $126 million, respectively, as of December 31, 2006. Under the provisions of its senior note indenture, JCP&L may issue additional FMB only as collateral for senior notes. As of December 31, 2006, JCP&L had the capability to issue $678 million of additional senior notes upon the basis of FMB collateral.

As of December 31, 2006, each of OE, TE, Penn and JCP&L have redeemed all of their outstanding preferred stock. As a result of these redemptions, the applicable earnings coverage tests in each of their respective charters are inoperative. In the event that any of OE, TE, Penn and JCP&L issues preferred stock in the future, the applicable earnings coverage test will govern the amount of preferred stock that may be issued. CEI, Met-Ed and Penelec do not have similar restrictions and could issue up to the number of preferred shares authorized under their respective charters.

As of December 31, 2006, approximately $1.0 billion of capacity remained unused under an existing FirstEnergy shelf registration statement filed with the SEC in 2003 to support future securities issuances. 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. As of December 31, 2006, OE and CEI had approximately $400 million and $250 million, respectively, of capacity remaining unused under their existing shelf registrations for unsecured debt securities filed with the SEC in 2006.

On August 24, 2006, FirstEnergy and certain of its subsidiaries entered into a new $2.75 billion five-year revolving credit facility (included in the borrowing capability table above), which replaced FirstEnergy's prior $2 billion credit facility. FirstEnergy may request an increase in the total commitments available under the new facility up to a maximum of $3.25 billion. Commitments under the new facility are available until August 24, 2011, unless the lenders agree, at the request of the Borrowers, to two additional one-year extensions. Generally, borrowings under the facility must be repaid within 364 days. Available amounts for each Borrower are subject to a specified sublimit, as well as applicable regulatory and other limitations.

The following table summarizes the borrowing sub-limits for each borrower under the facility, as well as the limitations on short-term indebtedness applicable to each borrower under current regulatory approvals and applicable statutory and/or charter limitations:

Borrower	Revolving Credit Facility Sub-Limit	Regulatory and Other Short-Term Debt Limitations[1]
	(In millions)	
FirstEnergy	$2,750	$1,500
OE	500	500
Penn	50	39
CEI	250[2]	600
TE	250[2]	500
JCP&L	425	414
Met-Ed	250	250[3]
Penelec	250	250[3]
FES	–[4]	n/a
ATSI	–[4]	50

[1] *As of December 31, 2006.*

[2] *Borrowing sub-limits for CEI and TE may be increased to up to $500 million by delivering notice to the administrative agent that such borrower has senior unsecured debt ratings of at least BBB by S&P and Baa2 by Moody's.*

[3] *Excluding amounts which may be borrowed under the regulated money pool.*

[4] *Borrowing sub-limits for FES and ATSI may be increased up to $250 million and $100 million, respectively, by delivering notice to the administrative agent that either (i) such borrower has senior unsecured debt ratings of at least BBB- by S&P and Baa3 by Moody's or (ii) FirstEnergy has guaranteed the obligations of such borrower under the facility.*

The revolving credit facility, combined with an aggregate $550 million (unused as of December 31, 2006) of accounts receivable financing facilities for OE, CEI, TE, Met-Ed, Penelec and Penn, are intended to provide liquidity to meet working capital requirements and for other general corporate purposes for FirstEnergy and its subsidiaries.

Under the revolving credit facility, borrowers may request the issuance of LOCs expiring up to one year from the date of issuance. The stated amount of outstanding LOCs will count against total commitments available under the facility and against the applicable borrower's borrowing sub-limit. Total unused borrowing capability under existing credit facilities and accounts receivable financing facilities was $1.8 billion as of December 31, 2006.

The revolving credit facility contains financial covenants requiring each borrower to maintain a consolidated debt to total capitalization ratio of no more than 65%, measured at the end of each fiscal quarter. As of December 31, 2006, FirstEnergy and its subsidiaries' debt to total capitalization ratios (as defined under the revolving credit facility) were as follows:

Borrower	
FirstEnergy	57%
OE	41%
Penn	24%
CEI	57%
TE	53%
JCP&L	24%
Met-Ed	42%
Penelec	33%

The revolving credit facility does not contain provisions that either restrict the ability to borrow or accelerate repayment of outstanding advances as a result of any change in credit ratings. Pricing is defined in "pricing grids", whereby the cost of funds borrowed under the facility is related to the credit ratings of the company borrowing the funds.

FirstEnergy's regulated companies also 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 FirstEnergy's 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. 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 2006 was approximately 5.22% for both the regulated companies' money pool and the unregulated companies' money pool.

FirstEnergy's access to capital markets and costs of financing are influenced by the ratings of its securities. The following table displays FirstEnergy's and the Companies' securities ratings as of February 2, 2007. The ratings outlook from S&P on all securities is stable. The ratings outlook from Moody's on all securities is Positive. The ratings outlook from Fitch is positive for CEI and TE and stable for all other securities.

Issuer	Securities	S&P	Moody's	Fitch
FirstEnergy	Senior unsecured	BBB-	Baa3	BBB
OE	Senior unsecured	BBB-	Baa2	BBB
CEI	Senior secured Senior unsecured	BBB BBB-	Baa2 Baa3	BBB BBB-
TE	Senior secured Senior unsecured	BBB BBB-	Baa2 Baa3	BBB BBB-
Penn	Senior secured	BBB+	Baa1	BBB+
JCP&L	Senior secured	BBB+	Baa1	A-
Met-Ed	Senior unsecured	BBB	Baa2	BBB
Penelec	Senior unsecured	BBB	Baa2	BBB

On January 20, 2006, TE redeemed all 1.2 million of its outstanding shares of Adjustable Rate Series B preferred stock at $25.00 per share, plus accrued dividends to the date of redemption.

On April 3, 2006, $253 million of pollution control revenue refunding bonds were issued by Ohio and Pennsylvania industrial development authorities on behalf of NGC ($106 million) and FGCO ($147 million). On December 5, 2006, $878 million of pollution control revenue refunding bonds were issued by such authorities on behalf of NGC ($485 million) and FGCO ($393 million). In each case, proceeds from the issuance and sale of the bonds were used to refund an equal aggregate amount of pollution control bonds previously issued in various series on behalf of OE, Penn, CEI and TE. The refundings resulted in corresponding reductions in each of the utility operating subsidiaries' notes receivable from NGC and FGCO relating to the generation asset transfers completed in 2005. All of the refunding issues are currently supported by bank LOCs for which FirstEnergy is either the account party or the guarantor of the reimbursement obligation of NGC or FGCO, as applicable. Provisions have been included in the April 2006 transactions, as well as other transactions, that permit FES to replace FirstEnergy as guarantor effective as early as 91 days after FES obtains senior unsecured debt ratings of at least BBB- by S&P and Baa3 by Moody's.

On May 12, 2006, JCP&L issued $200 million of 6.40% secured senior notes due 2036. The proceeds of the offering were used to repay at maturity $150 million aggregate principal amount of JCP&L's 6.45% senior notes due May 15, 2006 and for general corporate purposes.

On June 26, 2006, OE issued $600 million of unsecured senior notes, comprised of $250 million of 6.4% notes due 2016 and $350 million of 6.875% notes due 2036. The majority of the proceeds from this offering were used in July 2006 to repurchase $500 million of OE common stock from FirstEnergy, enabling FirstEnergy to redeem $400 million of the $1 billion outstanding principal amount of FirstEnergy's 5.5% senior notes prior to their November 15, 2006 scheduled maturity. The remainder of the proceeds were used to redeem approximately $61 million of OE's preferred stock on July 7, 2006 and to reduce short-term borrowings.

On August 10, 2006, JCP&L Transition Funding II, a wholly owned subsidiary of JCP&L, issued $182 million of transition bonds with a weighted average interest rate of 5.5% to securitize the recovery of deferred costs associated with JCP&L's supply of BGS. The majority of the proceeds were used in December 2006 to repurchase $77 million of JCP&L common stock from FirstEnergy. The remainder of the proceeds was used to redeem approximately $13 million of JCP&L's preferred stock on September 9, 2006, and to reduce short-term borrowings.

On November 18, 2006, TE issued $300 million of 6.15% senior unsecured notes due 2037. On December 11, 2006, CEI issued $300 million of 5.95% senior unsecured notes due 2036. TE and CEI used $225 million and $300 million, respectively, of the proceeds to repurchase common stock from FirstEnergy to provide funds for the repayment at maturity of a portion of the $1 billion outstanding principal amount of FirstEnergy's 5.5% senior notes that matured November 15, 2006. The remainder of TE's proceeds was used to redeem $66 million of TE's preferred stock in December 2006.

On December 15, 2006, Penn redeemed all of its outstanding shares of preferred stock for approximately $14 million, plus accrued dividends to the date of redemption.

On January 30, 2007, FirstEnergy's Board of Directors authorized a new share repurchase program for up to 16 million shares, or approximately 5% of the FirstEnergy's outstanding common stock. This new program supplements the prior repurchase program approved on June 20, 2006, such that up to 26.6 million potential shares may ultimately be repurchased under the combined plans. At management's discretion, shares may be acquired on the open market or through privately negotiated transactions, subject to market conditions and other factors. The Board's authorization of the repurchase program does not require FirstEnergy to purchase any shares and the program may be terminated at any time. Under the prior program, approximately 10.6 million shares were repurchased on August 10, 2006 at an initial purchase price of $600 million, or $56.44 per share. The final purchase price under that program will be adjusted to reflect the ultimate cost to acquire the shares over a period of up to seven months ending March 2007. FirstEnergy is currently in negotiations with a major financial institution to enter into a new accelerated share repurchase program contingent among other things on amending its current accelerated share repurchase program to allow FirstEnergy to enter into the new accelerated repurchase program.

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 power supply management services segment are principally generation-related. The following table summarizes investments for the three years ended December 31, 2006 by our regulated services, power supply management services and other segments:

Summary of Cash Flows Used for Investing Activities By Segment	Property Additions	Investments	Other	Total
		(In millions)		
2006 Sources (Uses)				
Regulated services	$ (633)	$ 147	$(10)	$ (496)
Power supply management services	(644)	(5)	(1)	(650)
Other	(1)	(26)	1	(26)
Reconciling adjustments	(37)	90	10	63
Total	$(1,315)	$ 206	$ –	$(1,109)
2005 Sources (Uses)				
Regulated services	$ (788)	$(106)	$(14)	$ (908)
Power supply management services	(375)	(19)	3	(391)
Other	(8)	18	(21)	(11)
Reconciling adjustments	(37)	13	1	(23)
Total	$(1,208)	$ (94)	$(31)	$(1,333)
2004 Sources (Uses)				
Regulated services	$ (572)	$ 184	$(88)	$ (476)
Power supply management services	(246)	(13)	(2)	(261)
Other	(7)	175	(4)	164
Reconciling adjustments	(21)	(2)	100	77
Total	$ (846)	$ 344	$ 6	$ (496)

Net cash used for investing activities in 2006 decreased by $224 million compared to 2005. The decrease was principally due to a $58 million increase in proceeds from asset sales (see Note 8), an $86 million decrease in net nuclear decommissioning trust activities due to the completion of the Ohio Companies' and Penn's transition cost recovery for decommissioning at the end of 2005 and a $163 million decrease in cash investments, primarily from the use of restricted cash investments to repay debt. These decreases were partially offset by a $107 million increase in property additions which reflects the replacement of the steam generators and reactor head at Beaver Valley Unit 1, air quality control system expenditures and the distribution system Accelerated Reliability Improvement Program.

Net cash used for investing activities in 2005 increased by $837 million from 2004. The increase was principally due to a $362 million increase in property additions, a $119 million decrease in proceeds from asset sales (see Note 8) and the absence in 2005 of cash proceeds of $278 million from certificates of deposit received by OE in 2004 when the certificates of deposit were no longer required to be held as collateral.

Our capital spending for the period 2007-2011 is expected to be nearly $8 billion (excluding nuclear fuel), of which $1.4 billion applies to 2007. Investments for additional nuclear fuel during the 2007-2011 period are estimated to be approximately $893 million, of which about $86 million applies to 2007. During the same period, our nuclear fuel investments are expected to be reduced by approximately $702 million and $103 million, respectively, as the nuclear fuel is consumed.

CONTRACTUAL OBLIGATIONS

As of December 31, 2006, our estimated cash payments under existing contractual obligations that we consider firm obligations are as follows:

Contractual Obligations	Total	2007	2008-2009	2010-2011	Thereafter
			(In millions)		
Long-term debt	$10,424	$ 241	$ 623	$1,739	$ 7,821
Short-term borrowings	1,108	1,108	–	–	–
Interest on long-term debt	9,564	609	1,172	1,110	6,673
Capital leases [1]	7	1	2	2	2
Operating leases [1]	2,298	204	449	416	1,229
Pension funding [2]	300	300	–	–	–
Fuel and purchased power [3]	16,108	2,809	4,927	3,835	4,537
Total	$39,809	$5,272	$7,173	$7,102	$20,262

[1] *See Note 6 to the consolidated financial statements.*

[2] *We estimate that no further pension contributions will be required during the 2008-2011 period 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 2011. See Note 3 to the consolidated financial statements.*

[3] *Amounts under contract with fixed or minimum quantities and approximate timing.*

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. These agreements include contract guarantees, surety bonds, and LOCs. Some of the guaranteed contracts contain collateral provisions that are contingent upon our credit ratings.

As of December 31, 2006, our maximum exposure to potential future payments under outstanding guarantees and other assurances totaled approximately $5.4 billion, as summarized below:

Guarantees and Other Assurances	Maximum Exposure
	(In millions)
FirstEnergy Guarantees of Subsidiaries	
Energy and Energy-Related Contracts [1]	$ 953
Other [2]	1,585
	2,538
Surety Bonds	130
LOC [3][4]	2,740
Total Guarantees and Other Assurances	$5,408

[1] *Issued for open-ended terms, with a 10-day termination right by FirstEnergy.*

[2] *Issued for various terms.*

[3] *Includes $479 million issued for various terms under LOC capacity available in FirstEnergy's revolving credit agreement and an additional $1.6 billion outstanding in support of pollution control revenue bonds issued with various maturities.*

[4] *Includes approximately $194 million pledged in connection with the sale and leaseback of Beaver Valley Unit 2 by CEI and TE, $291 million pledged in connection with the sale and leaseback of Beaver Valley Unit 2 by OE and $134 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. As of December 31, 2006, our maximum exposure under these collateral provisions was $468 million.

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 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 ($27 million as of December 31, 2006), 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 Unit1, Beaver Valley Unit2 and the Bruce Mansfield Plant, which are satisfied through operating lease payments. The present value of these sale and leaseback operating lease commitments, net of trust investments, total $1.2 billion as of December 31, 2006.

We have equity ownership interests in certain 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 will have a material current or future effect on our financial condition, liquidity or results of operations are disclosed under Guarantees and Other Assurances above.

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 oversight to risk management activities throughout the Company.

Commodity Price Risk

We are exposed to financial and market risks resulting from the fluctuation of interest rates and commodity prices — electricity, energy transmission, natural gas, coal, nuclear fuel and emission allowances. 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. Derivatives that fall within the scope of SFAS 133 must be recorded at their fair value and marked to market. The majority of our derivative hedging contracts qualify for the normal purchase and normal sale exception under SFAS 133 and are therefore excluded from the tables below. Contracts that are not exempt from such treatment include certain power purchase agreements with NUG entities that were structured pursuant to the Public Utility Regulatory Policies Act of 1978. These non-trading contracts are adjusted to fair value at the end of each quarter, with a corresponding regulatory asset recognized for above-market costs. On April 1, 2006, we elected to apply the normal purchase and normal sale exception to certain NUG power purchase agreements having a fair value of $13 million (included in "Other" in the table below). The change in the fair value of commodity derivative contracts related to energy production during 2006 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 liability as of January 1, 2006	$(1,170)	$ (3)	$(1,173)
New contract value when entered	–	–	–
Additions/change in value of existing contracts	(244)	(23)	(267)
Change in techniques/assumptions	–	–	–
Settled contracts	287	9	296
Other	(13)	–	(13)
Outstanding net liability as of December 31, 2006[1]	$(1,140)	$(17)	$(1,157)
Non-commodity net liabilities as of December 31, 2006:			
Interest rate swaps[2]	–	(39)	(39)
Net Liabilities - Derivative Contracts as of December 31, 2006	$(1,140)	$(56)	$(1,196)
Impact of Changes in Commodity Derivative Contracts[3]			
Income Statement effects (pre-tax)	$ (3)	$ –	$ (3)
Balance Sheet effects:			
OCI (pre-tax)	$ –	$(14)	$ (14)
Regulatory asset (net)	$ (46)	$ –	$ (46)

[1] *Includes $1.14 billion in non-hedge commodity derivative contracts (primarily with NUGs), which are offset by a regulatory asset.*

[2] *Interest rate swaps are treated as cash flow or fair value hedges (see Interest Rate Swap Agreements below).*

[3] *Represents the change in value of existing contracts, settled contracts and changes in techniques/ assumptions.*

Derivatives are included on the Consolidated Balance Sheet as of December 31, 2006 as follows:

Balance Sheet Classification	**Non-Hedge**	**Hedge**	**Total**
		(In millions)	
Current-			
Other assets	$ –	$ 21	$ 21
Other liabilities	(4)	(38)	(42)
Non-Current-			
Other deferred charges	46	16	62
Other noncurrent liabilities	(1,182)	(55)	(1,237)
Net liabilities	$(1,140)	$(56)	$(1,196)

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 as of December 31, 2006 are summarized by year in the following table:

Source of Information - Fair Value by Contract Year	**2007**	**2008**	**2009**	**2010**	**2011**	**Thereafter**	**Total**
			(In millions)				
Prices actively quoted[1]	$ (3)	$ –	$ –	$ –	$ –	$ –	$ (3)
Other external sources[2]	(323)	(249)	(193)	–	–	–	(765)
Prices based on models	–	–	–	(185)	(105)	(99)	(389)
Total[3]	$(326)	$(249)	$(193)	$(185)	$(105)	$(99)	$(1,157)

[1] *Exchange traded.*

[2] *Broker quote sheets.*

[3] *Includes $1.14 billion in non-hedge commodity derivative contracts (primarily with NUGs), which are offset by a regulatory asset.*

We perform sensitivity analyses to estimate our exposure to the market risk of our commodity positions. A hypothetical 10% adverse shift (an increase or decrease depending on the derivative position) in quoted market prices in the near term on our derivative instruments would not have had a material effect on our consolidated financial position (assets, liabilities and equity) or cash flows as of December 31, 2006. Based on derivative contracts held as of December 31, 2006, an adverse 10% change in commodity prices would decrease net income by approximately $2 million for the next twelve months.

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**	**2007**	**2008**	**2009**	**2010**	**2011**	**There-after**	**Total**	**Fair Value**
				(Dollars in millions)				
Assets								
Investments other than Cash and Cash Equivalents-Fixed Income	$ 100	$ 57	$ 68	$ 84	$ 92	$1,565	$1,966	$2,068
Average interest rate	7.1%	7.7%	7.9%	7.9%	7.9%	5.6%	6.0%	
Liabilities								
Long-term Debt and Other Long-term Obligations:								
Fixed rate[1]	$ 241	$ 336	$ 287	$199	$1,540	$5,820	$8,423	$8,829
Average interest rate	6.5%	5.2%	6.7%	5.4%	6.4%	6.5%	6.4%	
Variable rate[1]						$2,001	$2,001	$2,001
Average interest rate						3.9%	3.9%	
Short-term Borrowings	$1,108						$1,108	$1,108
Average interest rate	5.7%						5.7%	

[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. Fluctuations in the fair value of NGC's and the Ohio Companies' decommissioning trust balances will eventually affect earnings (immediately for unrealized losses and affecting OCI initially for unrealized gains) based on the guidance in SFAS 115, FSP SFAS 115-1 and SFAS 124-1. Our Pennsylvania and New Jersey companies, however, 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, 2006, our decommissioning trust balances totaled $2.0 billion, with $1.4 billion held by NGC and our Ohio Companies and the remaining balance held by JCP&L, Met-Ed and Penelec. As of year-end 2006, the trust balances of NGC and our Ohio Companies were comprised of 67% equity securities and 33% debt instruments.

Interest Rate Swap Agreements - Fair Value Hedges

We utilize fixed-for-floating interest rate swap agreements as part of our ongoing effort to manage the interest rate risk associated with 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 when interest rates decrease. Swap maturities, call options, fixed interest rates and interest payment dates match those of the underlying obligations. During 2006, we unwound swaps with a total notional amount of $350 million for which we incurred $1 million in cash losses. The losses will be recognized over the remaining maturity of each respective hedged security as increased interest expense. As of December 31, 2006, the debt underlying the $750 million outstanding notional amount of interest rate swaps had a weighted average fixed interest rate of 5.74%, which the swaps have effectively converted to a current weighted average variable rate of 6.42%.

	December 31, 2006			December 31, 2005		
Interest Rate Swaps	Notional Amount	Maturity Date	Fair Value	Notional Amount	Maturity Date	Fair Value
			(In millions)			
Fair value hedges	$100	2008	$ (2)	$ 100	2008	$ (3)
	50	2010	(1)	50	2010	–
	–	2011	–	50	2011	–
	300	2013	(6)	450	2013	(4)
	150	2015	(10)	150	2015	(9)
	–	2016	–	150	2016	–
	50	2025	(2)	50	2025	(1)
	100	2031	(6)	100	2031	(5)
	$750		$(27)	$1,100		$(22)

Forward Starting Swap Agreements - Cash Flow Hedges

We utilize forward starting swap agreements (forward swaps) in order to hedge a portion of the consolidated interest rate risk associated with the anticipated future issuances of fixed-rate, long-term debt securities for one or more of our consolidated subsidiaries in 2007 and 2008. These derivatives are treated as cash flow hedges, protecting against the risk of changes in future interest payments resulting from changes in benchmark U.S. Treasury rates between the date of hedge inception and the date of the debt issuance. During 2006, we revised the tenor and timing of our financing plans and, ultimately, terminated forward swaps with an aggregate notional value of $1.2 billion concurrent with our subsidiaries issuing long-term debt. We received $40 million in cash related to the terminations. The gain associated with the ineffective portion of the terminated hedges of $5.4 million was recognized in earnings, with the remainder to be recognized over the terms of the associated future debt. As of December 31, 2006, FirstEnergy had outstanding forward swaps with an aggregate notional amount of $300 million and an aggregate fair value of ($4) million.

	December 31, 2006			December 31, 2005		
Forward Starting Swaps	Notional Amount	Maturity Date	Fair Value	Notional Amount	Maturity Date	Fair Value
			(In millions)			
Cash flow hedges	$ 25	2015	$ –	$ 25	2015	$ –
	–	2016	–	600	2016	2
	200	2017	(4)	25	2017	–
	25	2018	(1)	275	2018	1
	50	2020	1	50	2020	–
	$300		$(4)	$975		$ 3

Equity Price Risk

Included in nuclear decommissioning trusts are marketable equity securities carried at their current fair value of approximately $1.3 billion and $1.1 billion as of December 31, 2006 and 2005, respectively. A hypothetical 10% decrease in prices quoted by stock exchanges would result in a $128 million reduction in fair value as of December 31, 2006 (see Note 5(B)).

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 our 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, 2006, the largest credit concentration with one party (currently rated investment grade) represented 11.6% of our total credit risk. Within our unregulated energy subsidiaries, 99% of credit exposures, net of collateral and reserves, were with investment-grade counterparties as of December 31, 2006.

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 Companies and ATSI 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. Regulatory assets that do not earn a current return totaled approximately $200 million as of December 31, 2006. The following table discloses the regulatory assets by company:

Regulatory Assets*	December 31, 2006	December 31, 2005	Increase (Decrease)
		(In millions)	
OE	$ 741	$ 775	$(34)
CEI	855	862	(7)
TE	248	287	(39)
JCP&L	2,152	2,227	(75)
Met-Ed	409	310	99
ATSI	36	25	11
Total	$4,441	$4,486	$(45)

** Penn had net regulatory liabilities of approximately $69 million and $59 million as of December 31, 2006 and 2005. Penelec had net regulatory liabilities of approximately $96 million and $163 million as of December 31, 2006 and 2005, respectively. These net regulatory liabilities are included in Other Non-current Liabilities on the Consolidated Balance Sheets.*

Regulatory assets by source are as follows:

Regulatory Assets by Source	December 31, 2006	December 31, 2005	Increase (Decrease)
		(In millions)	
Regulatory transition costs	$3,266	$3,576	$(310)
Customer shopping incentives	603	884	(281)
Customer receivables for future income taxes	217	217	–
Societal benefits charge	11	29	(18)
Loss on reacquired debt	43	41	2
Employee postretirement benefits	47	55	(8)
Nuclear decommissioning, decontamination and spent fuel disposal costs	(145)	(126)	(19)
Asset removal costs	(168)	(365)	197
Property losses and unrecovered plant costs	19	29	(10)
MISO/PJM transmission costs	213	91	122
Fuel costs - RCP	113	–	113
Distribution costs - RCP	155	–	155
Other	67	55	12
Total	$4,441	$4,486	$ (45)

Ohio

On October 21, 2003, the Ohio Companies filed their RSP case with the PUCO. On August 5, 2004, the Ohio Companies accepted the RSP as modified and approved by the PUCO in an August 4, 2004 Entry on Rehearing, subject to a CBP. The RSP was intended to establish generation service rates beginning January 1, 2006, in response to the PUCO's concerns about price and supply uncertainty following the end of the Ohio Companies' transition plan market development period. On May 3, 2006, the Supreme Court of Ohio issued an opinion affirming the PUCO's order in all respects, except it remanded back to the PUCO the matter of ensuring the availability of sufficient means for customer participation in the marketplace. The RSP contained a provision that permitted the Ohio Companies to withdraw and terminate the RSP in the event that the PUCO, or the Supreme Court of Ohio, rejected all or part of the RSP. In such event, the Ohio Companies have 30 days from the final order or decision to provide notice of termination. On July 20, 2006 the Ohio Companies filed with the PUCO a Request to Initiate a Proceeding on Remand. In their Request, the Ohio Companies provided notice of termination to those provisions of the RSP subject to termination, subject to being withdrawn, and also set forth a framework for addressing the Supreme Court of Ohio's findings on customer participation. If the PUCO approves a resolution to the issues raised by the Supreme Court of Ohio that is acceptable to the Ohio Companies, the Ohio Companies' termination will be withdrawn and considered to be null and void. On July 26, 2006, the PUCO issued an Entry directing the Ohio Companies to file a plan in a new docket to address the Court's concern. The Ohio Companies filed their RSP Remand CBP on September 29, 2006. Initial comments were filed on January 12, 2007 and reply comments were filed on January 29, 2007. In their reply comments the Ohio Companies described the highlights of a new tariff offering they would be willing to make available to customers that would allow customers to purchase renewable energy certificates associated with a renewable generation source, subject to PUCO approval. No further proceedings are scheduled at this time.

The Ohio Companies filed an application and stipulation with the PUCO on September 9, 2005 seeking approval of the RCP, a supplement to the RSP. On November 4, 2005, the Ohio Companies filed a supplemental stipulation with the PUCO, which constituted an additional component of the RCP filed on September 9, 2005. Major provisions of the RCP include:

- Maintaining the existing level of base distribution rates through December 31, 2008 for OE and TE, and April 30, 2009 for CEI;
- Deferring and capitalizing for future recovery (over a 25-year period) with carrying charges certain distribution costs to be incurred during the period January 1, 2006 through December 31, 2008, not to exceed $150 million in each of the three years;
- Adjusting the RTC and extended RTC recovery periods and rate levels so that full recovery of authorized costs will occur as of December 31, 2008 for OE and TE and as of December 31, 2010 for CEI;
- Reducing the deferred shopping incentive balances as of January 1, 2006 by up to $75 million for OE, $45 million for TE, and $85 million for CEI by accelerating the application of each respective company's accumulated cost of removal regulatory liability; and

- Recovering increased fuel costs (compared to a 2002 baseline) of up to $75 million, $77 million, and $79 million, in 2006, 2007, and 2008, respectively, from all OE and TE distribution and transmission customers through a fuel recovery mechanism. OE, TE, and CEI may defer and capitalize (for recovery over a 25-year period) increased fuel costs above the amount collected through the fuel recovery mechanism.

The following table provides the estimated net amortization of regulatory transition costs and deferred shopping incentives (including associated carrying charges) under the RCP for the period 2007 through 2010:

Amortization Period	OE	CEI	TE	Total Ohio
		(In millions)		
2007	$179	$108	$ 93	$ 380
2008	208	124	119	451
2009	–	216	–	216
2010	–	273	–	273
Total Amortization	$387	$721	$212	$1,320

On January 4, 2006, the PUCO approved, with modifications, the Ohio Companies' RCP to supplement the RSP to provide customers with more certain rate levels than otherwise available under the RSP during the plan period. On January 10, 2006, the Ohio Companies filed a Motion for Clarification seeking clarity on a number of issues. On January 25, 2006, the PUCO issued an Entry on Rehearing granting in part, and denying in part, the Ohio Companies' previous requests and clarifying issues referred to above. The PUCO granted the Ohio Companies' requests to:

- Recognize fuel and distribution deferrals commencing January 1, 2006;
- Recognize distribution deferrals on a monthly basis prior to review by the PUCO Staff;
- Clarify that the types of distribution expenditures included in the Supplemental Stipulation may be deferred; and
- Clarify that distribution expenditures do not have to be "accelerated" in order to be deferred.

The PUCO approved the Ohio Companies' methodology for determining distribution deferral amounts, but denied the Motion in that the PUCO Staff must verify the level of distribution expenditures contained in current rates, as opposed to simply accepting the amounts contained in the Ohio Companies' Motion. On February 3, 2006, several other parties filed applications for rehearing, which the PUCO denied on March 1, 2006. Two of these parties subsequently filed notices of appeal with the Supreme Court of Ohio. The Ohio Supreme Court scheduled this case for oral argument on February 27, 2007. On January 31, 2007, the Ohio Companies filed a stipulation which, among other matters and subject to PUCO approval, affirmed that the supplemental stipulation in the RCP would be implemented. This stipulation was approved by the PUCO on February 14, 2007.

On December 30, 2004, the Ohio Companies filed with the PUCO two applications related to the recovery of transmission and ancillary service related costs. The first application sought recovery of these costs beginning January 1, 2006. The Ohio Companies requested that these costs be recovered through a rider that would be effective on January 1, 2006 and adjusted each July 1 thereafter. The parties reached a settlement agreement that was approved by the PUCO on August 31, 2005. The incremental transmission and ancillary service revenues recovered from January 1 through June 30, 2006 were approximately $54 million. That amount included the recovery of a portion of the 2005 deferred MISO expenses as described below. On April 27, 2006, the Ohio Companies filed the annual update rider to determine revenues ($124 million) from July 2006 through June 2007. The filed rider went into effect on July 1, 2006.

The second application sought authority to defer costs associated with transmission and ancillary service related costs incurred during the period October 1, 2003 through December 31, 2005. On May 18, 2005, the PUCO granted the accounting authority for the Ohio Companies to defer incremental transmission and ancillary service-related charges incurred as a participant in MISO, but only for those costs incurred during the period December 30, 2004 through December 31, 2005. Permission to defer costs incurred prior to December 30, 2004 was denied. The PUCO also authorized the Ohio Companies to accrue carrying charges on the deferred balances. On August 31, 2005, the OCC appealed the PUCO's decision. On January 20, 2006, the OCC sought rehearing of the PUCO's approval of the recovery of deferred costs through the rider during the period January 1, 2006 through June 30, 2006. The PUCO denied the OCC's application on February 6, 2006. On March 23, 2006, the OCC appealed the PUCO's order to the Ohio Supreme Court. On March 27, 2006, the OCC filed a motion to consolidate this appeal with the deferral appeals discussed above and to postpone oral arguments in the deferral appeal until after all briefs are filed in this most recent appeal of the rider recovery mechanism. On March 20, 2006, the Ohio Supreme Court, on its own motion, consolidated the OCC's appeal of the Ohio Companies' case with a similar case involving Dayton Power & Light Company. Oral arguments were heard on May 10, 2006. On November 29, 2006, the Ohio Supreme Court issued its opinion upholding the PUCO's determination that the Ohio Companies may defer transmission and ancillary service related costs incurred on and after December 30, 2004. The Ohio Supreme Court also determined that the PUCO erred when it denied the OCC intervention, but further ruled that such error did not prejudice OCC and, therefore, the Ohio Supreme Court did not reverse or remand the PUCO on this ground. The Ohio Supreme Court also determined that the OCC's appeal was not premature. No party filed a motion for reconsideration with the Ohio Supreme Court.

Pennsylvania

Met-Ed and Penelec have been purchasing a portion of their PLR requirements from FES through a partial requirements wholesale power sales agreement and various amendments. Under these agreements, FES retained 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. The FES agreements have reduced Met-Ed's and Penelec's exposure to high wholesale power prices by providing power at a fixed price for their uncommitted PLR capacity and energy costs during the term of these agreements with FES.

On April 7, 2006, the parties entered into a Tolling Agreement that arose from FES' notice to Met-Ed and Penelec that FES elected to exercise its right to terminate the partial requirements agreement effective midnight December 31, 2006.

On November 29, 2006, Met-Ed, Penelec and FES agreed to suspend the April 7 Tolling Agreement pending resolution of the PPUC's proceedings regarding the Met-Ed and Penelec Transition Rate cases filed April 10, 2006, described below. Separately, on September 26, 2006, Met-Ed and Penelec successfully conducted a competitive RFP for a portion of their PLR obligation for the period December 1, 2006 through December 31, 2008. FES was one of the successful bidders in that RFP process and on September 26, 2006 entered into a Supplier Master Agreement to supply a certain portion of Met-Ed's and Penelec's PLR requirements at market prices that substantially exceed the fixed price in the partial requirements agreements.

Based on the outcome of the Transition Rate filing, as described below, Met-Ed, Penelec and FES agreed to restate the partial requirements power sales agreement effective January 1, 2007. The restated agreement incorporates the same fixed price for residual capacity and energy supplied by FES as in the prior arrangements between the parties, and automatically extends for successive one year terms unless any party gives 60 days' notice prior to the end of the year. The restated agreement allows Met-Ed and Penelec to sell the output of NUG generation to the market and requires FES to provide energy at fixed prices to replace any NUG energy thus sold to the extent needed for Met-Ed and Penelec to satisfy their PLR obligations. The parties have also separately terminated the Tolling, Suspension and Supplier Master agreements in connection with the restatement of the partial requirements agreement. Accordingly, the energy that would have been supplied under the Master Supplier Agreement will now be provided under the restated partial requirements agreement.

If Met-Ed and Penelec were to replace the entire FES supply at current market power prices without corresponding regulatory authorization to increase their generation prices to customers, each company would likely incur a significant increase in operating expenses and experience a material deterioration in credit quality metrics. Under such a scenario, each company's credit profile would no longer be expected to support an investment grade rating for its fixed income securities. Based on the PPUC's January 11, 2007 order described below, if FES ultimately determines to terminate, reduce, or significantly modify the agreement prior to the expiration of Met-Ed's and Penelec's generation rate caps in 2010, timely regulatory relief is not likely to be granted by the PPUC.

Met-Ed and Penelec made a comprehensive rate filing with the PPUC on April 10, 2006 to address a number of transmission, distribution and supply issues. If Met-Ed's and Penelec's preferred approach involving accounting deferrals was approved, the filing would have increased annual revenues by $216 million and $157 million, respectively. That filing included, among other things, a request to charge customers for an increasing amount of market priced power procured through a CBP as the amount of supply provided under the then existing FES agreement is phased out in accordance with the April 7, 2006 Tolling Agreement described above. Met-Ed and Penelec also requested approval of the January 12, 2005 petition for the deferral of transmission-related costs discussed above, but only for those costs incurred during 2006. In this rate filing, Met-Ed and Penelec also requested recovery of annual transmission and related costs incurred on or after January 1, 2007, plus the amortized portion of 2006 costs over a ten-year period, along with applicable carrying charges, through an adjustable rider similar to that implemented in Ohio. Changes in the recovery of NUG expenses and the recovery of Met-Ed's non-NUG stranded costs were also included in the filing. Hearings were held in late August 2006 and briefing occurred in September and October. The ALJs issued their Recommended Decision on November 2, 2006.

The PPUC entered its Opinion and Order in the rate filing proceeding on January 11, 2007. The Order approved the recovery of transmission costs, including the 2006 deferral, and determined that no merger savings from prior years should be considered in determining customers' rates. The request for increases in generation supply rates was denied as were the requested changes in NUG expense recovery and Met-Ed's non-NUG stranded costs. The order decreased Met-Ed's and Penelec's distribution rates by $80 million and $19 million, respectively. These decreases were offset by the increases allowed for the recovery of transmission expenses and the 2006 transmission deferral. Met-Ed's and Penelec's request for recovery of Saxton decommissioning costs was granted and in January 2007, they recognized income of $27 million to establish a regulatory asset for the previously expensed decommissioning costs. Overall rates increased by 5.0% for Met-Ed ($59 million) and 4.5% for Penelec ($50 million). Met-Ed and Penelec filed a Petition for Reconsideration on January 26, 2007 on the issues of consolidated tax savings and rate of return on equity. Other parties filed Petitions for Reconsideration on transmission congestion, transmission deferrals and rate design issues. The PPUC on February 8, 2007 entered an order granting Met-Ed's, Penelec's and the other parties' petitions for procedural purposes. Due to that ruling, the period for appeals to the Commonwealth Court is tolled until 30 days after the PPUC enters a subsequent order ruling on the substantive issues raised in the petitions.

As of December 31, 2006, Met-Ed's and Penelec's regulatory deferrals pursuant to the 1998 Restructuring Settlement (including the Phase 2 Proceedings) and the FirstEnergy/GPU Merger Settlement Stipulation were $303 million and $70 million, respectively. Penelec's $70 million deferral is subject to final resolution of an IRS settlement associated with NUG trust fund proceeds. During the PPUC's annual audit of Met-Ed's and Penelec's NUG stranded cost balances in 2006, it noted a modification to the NUG purchased power stranded cost accounting methodology made by Met-Ed and Penelec. On August 18, 2006, a PPUC Order was entered requiring Met-Ed and Penelec to reflect the deferred NUG cost balances as if the stranded cost accounting methodology modification had not been implemented. As a result of the PPUC's Order, Met-Ed recognized a pre-tax charge of approximately $10.3 million in the third quarter of 2006, representing incremental costs deferred under the revised methodology in 2005. Met-Ed and Penelec continue to believe that the stranded cost accounting methodology modification is appropriate and on August 24, 2006 filed a petition with the PPUC pursuant to its Order for authorization to reflect the stranded cost accounting methodology modification effective January 1, 1999. Hearings on this petition are scheduled for late February 2007. It is not known when the PPUC may issue a final decision in this matter.

On February 1, 2007 the Governor of Pennsylvania proposed an Energy Independence Strategy (EIS). The EIS includes four pieces of preliminary draft legislation that, according to the Governor, is designed to reduce energy costs, promote energy independence and stimulate the economy. Elements of the EIS include the installation of smart meters, funding for solar panels on residences and small businesses, conservation programs to meet demand growth, a requirement that electric distribution companies acquire power through a "Least Cost Portfolio", the utilization of micro-grids and a three year phase-in of rate increases. Since the EIS has only recently been proposed, the final form of any legislation is uncertain. Consequently, FirstEnergy is unable to predict what impact, if any, such legislation may have on its operations.

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 NUGC rates and market sales of NUG energy and capacity. As of December 31, 2006, the accumulated deferred cost balance totaled approximately $369 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 to securitize the July 31, 2003 deferred balance. On June 8, 2006, the NJBPU approved JCP&L's request to issue securitization bonds associated with BGS stranded cost deferrals. On August 10, 2006, JCP&L Transition Funding II, a wholly owned subsidiary of JCP&L, issued $182 million of transition bonds with a weighted average interest rate of 5.5%.

On December 2, 2005, JCP&L filed its request for recovery of $165 million of actual above-market NUG costs incurred from August 1, 2003 through October 31, 2005 and forecasted above-market NUG costs for November and December 2005. On February 23, 2006, JCP&L filed updated data reflecting actual amounts through December 31, 2005 of $154 million of costs incurred since July 31, 2003. On July 18, 2006, JCP&L further requested an additional $14 million of costs that had been eliminated from the securitized amount. A Stipulation of Settlement was signed by all parties, approved by the ALJ and adopted by the NJBPU in its Order dated December 6, 2006. The Order approves an annual $110 million increase in NUGC rates designed to recover deferred costs incurred since August 1, 2003, and a portion of costs incurred prior to August 1, 2003 that were not securitized. The Order requires that JCP&L absorb any net annual operating losses associated with the Forked River Generating Station. In the Settlement, JCP&L also agreed not to seek an increase to the NUGC to become effective before January 2010, unless the deferred balance exceeds $350 million any time after June 30, 2007.

Reacting to the higher closing prices of the 2006 BGS fixed rate auction, the NJBPU, on March 16, 2006, initiated a generic proceeding to evaluate the auction process and potential options for the future. On April 6, 2006, initial comments were submitted. A public meeting was held on April 21, 2006 and a legislative-type hearing was held on April 28, 2006. On June 21, 2006, the NJBPU approved the continued use of a descending block auction for the Fixed Price Residential Class. JCP&L filed its 2007 BGS company specific addendum on July 10, 2006. On October 27, 2006, the NJBPU approved the auction format to procure the 2007 Commercial Industrial Energy Price as well as the specific rules for both the Fixed Price and Commercial Industrial Energy Price auctions. These rules were essentially unchanged from the prior auctions.

On August 1, 2005, the NJBPU established a proceeding to determine whether additional ratepayer protections are required at the state level in light of the repeal of PUHCA pursuant to the EPACT. The NJBPU approved regulations effective October 2, 2006 that would prevent a holding company that owns a gas or electric public utility from investing more than 25% of the combined assets of its utility and utility-related subsidiaries into businesses unrelated to the utility industry. These regulations are not expected to materially impact FirstEnergy or JCP&L. Also, in the same proceeding, the NJBPU Staff issued an additional draft proposal on March 31, 2006 addressing various issues including access to books and records, ring-fencing, cross subsidization, corporate governance and related matters. With the approval of the NJBPU Staff, the affected utilities jointly submitted an alternative proposal on June 1, 2006. Comments on the alternative proposal were submitted on June 15, 2006. On November 3, 2006, the NJBPU Staff circulated a revised draft proposal to interested stakeholders.

New Jersey statutes require that the state periodically undertake a planning process, known as the Energy Master Plan (EMP), to address energy related issues including energy security, economic growth, and environmental impact. The EMP is to be developed with involvement of the Governor's Office and the Governor's Office of Economic Growth, and is to be prepared by a Master Plan Committee, which is chaired by the NJBPU President and includes representatives of several State departments.

In October 2006 the current EMP process was initiated with the issuance of a proposed set of objectives which, as to electricity, included the following:

- Reduce the total projected electricity demand by 20% by 2020;
- Meet 22.5% of the State's electricity needs with renewable energy resources by that date;
- Reduce air pollution related to energy use;
- Encourage and maintain economic growth and development;
- Achieve a 20% reduction in both Customer Average Interruption Duration Index and System Average Interruption Frequency Index by 2020;
- Unit prices for electricity should remain no more than +5% of the regional average price (region includes New York, New Jersey, Pennsylvania, Delaware, Maryland and the District of Columbia); and
- Eliminate transmission congestion by 2020.

Comments on the objectives and participation in the development of the EMP have been solicited and a number of working groups have been formed to attain input from a broad range of interested stakeholders including utilities, environmental groups, customer groups, and major customers. Public stakeholder meetings were held in the fall of 2006 and in early 2007, and further public meetings are expected in the summer of 2007. A final draft of the EMP is expected to be presented to the Governor in the fall of 2007 with further public hearings anticipated in early 2008. At this time we cannot predict the outcome of this process nor determine its impact.

See Note 10 to the consolidated financial statements for further details and a complete discussion of regulatory matters in New Jersey.

FERC Matters

On March 28, 2006, ATSI and MISO filed with the FERC a request to modify ATSI's Attachment O formula rate to include revenue requirements associated with recovery of deferred Vegetation Management Enhancement Program (VMEP) costs. ATSI estimated that it may defer approximately $54 million of such costs over a five-year period. Approximately $42 million has been deferred as of December 31, 2006. The effective date for recovery was June 1, 2006. The FERC conditionally approved the filing on May 22, 2006, and on July 14, 2006 FERC accepted the ATSI compliance filing. A request for rehearing of the FERC's May 22, 2006 Order was denied by FERC on October 25, 2006. The estimated annual revenues to ATSI from the VMEP cost recovery is $12 million for each of the five years beginning June 1, 2006.

On January 24, 2006, ATSI and MISO filed a request with the FERC to correct ATSI's Attachment O formula rate to reverse revenue credits associated with termination of revenue streams from transitional rates stemming from FERC's elimination of RTOR between the Midwest ISO and PJM. Revenues formerly collected under these transitional rates were included in, and served to reduce, ATSI's zonal transmission rate under the Attachment O formula. Absent the requested correction, elimination of these revenue credits would not be fully reflected in ATSI's formula rate until June 1, 2008. On March 16, 2006, the FERC approved the revenue credit correction without suspension, effective April 1, 2006. One party sought rehearing of the FERC's order, which was denied on June 27, 2006. No petition for review of the FERC's decision was filed. The estimated revenue impact of the correction mechanism is approximately $37 million for the period June 1, 2006 through May 31, 2007.

On November 18, 2004, the FERC issued an order eliminating the RTOR for transmission service between the MISO and PJM regions. The FERC also ordered the MISO, PJM and the transmission owners within MISO and PJM to submit compliance filings containing a SECA mechanism to recover lost RTOR revenues during a 16-month transition period from load serving entities. The FERC issued orders in 2005 setting the SECA for hearing. ATSI, JCP&L, Met-Ed, Penelec, and FES participated in the FERC hearings held in May 2006 concerning the calculation and imposition of the SECA charges. The Presiding Judge issued an Initial Decision on August 10, 2006, rejecting the compliance filings made by the RTOs and transmission owners, ruling on various issues and directing new compliance filings. This decision is subject to review and approval by the FERC. Briefs addressing the Initial Decision were filed on September 11, 2006 and October 20, 2006. A final order could be issued by the FERC in early 2007.

On January 31, 2005, certain PJM transmission owners made three filings with the FERC pursuant to a settlement agreement previously approved by the FERC. JCP&L, Met-Ed and Penelec were parties to that proceeding and joined in two of the filings. In the first filing, the settling transmission owners submitted a filing justifying continuation of their existing rate design within the PJM RTO. In the second filing, the settling transmission owners proposed a revised Schedule 12 to the PJM tariff designed to harmonize the rate treatment of new and existing transmission facilities. Interventions and protests were filed on February 22, 2005. In the third filing, Baltimore Gas and Electric Company and Pepco Holdings, Inc. requested a formula rate for transmission service provided within their respective zones. On May 31, 2005, the FERC issued an order on these cases. First, it set for hearing the existing rate design and indicated that it will issue a final order within six months. American Electric Power Company, Inc. filed in opposition proposing to create a "postage stamp" rate for high voltage transmission facilities across PJM. Second, the FERC approved the proposed Schedule 12 rate harmonization. Third, the FERC accepted the proposed formula rate, subject to refund and hearing procedures. On June 30, 2005, the settling PJM transmission owners filed a request for rehearing of the May 31, 2005 order. On March 20, 2006, a settlement was filed with FERC in the formula rate proceeding that generally accepts the companies' formula rate proposal. The FERC issued an order approving this settlement on April 19, 2006. Hearings in the PJM rate design case concluded in April 2006. On July 13, 2006, an Initial Decision was issued by the ALJ. The ALJ adopted the FERC Trial Staff's position that the cost of all PJM transmission facilities should be recovered through a postage stamp rate. The ALJ recommended an April 1, 2006 effective date for this change in rate design. If the FERC accepts this recommendation, the transmission rate applicable to many load zones in PJM would increase. We believe that significant additional transmission revenues would have to be recovered from the JCP&L, Met-Ed and Penelec transmission zones within PJM. JCP&L, Met-Ed and Penelec, as part of the Responsible Pricing Alliance, filed a brief addressing the Initial Decision on August 14, 2006 and September 5, 2006. The case will be reviewed by the FERC with a decision anticipated in early 2007.

On November 1, 2005, FES filed two power sales agreements for approval with the FERC. One power sales agreement provided for FES to provide the PLR requirements of the Ohio Companies at a price equal to the retail generation rates approved by the PUCO for a period of three years beginning January 1, 2006. The Ohio Companies will be relieved of their obligation to obtain PLR power requirements from FES if the Ohio CBP results in a lower price for retail customers. A similar power sales agreement between FES and Penn permits Penn to obtain its PLR power requirements from FES at a fixed price equal to the retail generation price during 2006.

On December 29, 2005, the FERC issued an order setting the two power sales agreements for hearing. The order criticized the Ohio CBP, and required FES to submit additional evidence in support of the reasonableness of the prices charged in the power sales agreements. On July 14, 2006, the Chief Judge granted the joint motion of FES and the Trial Staff to appoint a settlement judge in this proceeding and the procedural schedule was suspended pending settlement discussions among the parties. A settlement conference was held on September 5, 2006. FES and the Ohio Companies, Penn, and the PUCO, along with other parties, reached an agreement to settle the case. The settlement was filed with the FERC on October 17, 2006, and was unopposed by the remaining parties, including the FERC Trial Staff. This settlement was accepted by the FERC on December 8, 2006.

The terms of the settlement provide for modification of both the Ohio and Penn power supply agreements with FES. Under the Ohio power supply agreement, separate rates are established for the Ohio Companies' PLR requirements; special retail contract requirements, wholesale contract requirements, and interruptible buy-through retail load requirements. For their PLR and special retail contract requirements, the Ohio Companies will pay FES no more than the lower of (i) the sum of the retail generation charge, the rate stabilization charge, the fuel recovery mechanism charge, and FES' actual incremental fuel costs for such sales; or (ii) the wholesale price cap. Different wholesale price caps are imposed for PLR sales, special retail contracts, and wholesale contracts. The wholesale price for interruptible buy-through retail load requirements is limited to the actual spot price of power obtained by FES to provide this power. FES billed the Ohio Companies for the additional amount payable to FES for incremental fuel costs on power supplied during 2006. The total power supply cost billed by FES was lower in each case than the wholesale price caps specified in the settlement accepted by the FERC. In addition, pursuant to the settlement, the wholesale rate charged by FES under the Penn power supply agreement can be no greater than the generation component of charges for retail PLR load in Pennsylvania. The modifications to the Ohio and Pennsylvania power supply agreements became effective January 1, 2006. The Penn supply agreement subject to the settlement expired at midnight on December 31, 2006.

As a result of Penn's PLR competitive solicitation process approved by the PPUC for the period January 1, 2007 through May 31, 2008, FES was selected as the winning bidder for a number of the tranches for individual customer classes. The balance of the tranches will be supplied by unaffiliated power suppliers. On October 2, 2006, FES filed an application with the FERC under Section 205 of the Federal Power Act for authorization to make these affiliate sales to Penn. Interventions or protests were due on this filing on October 23, 2006. Penn was the only party to file an intervention in this proceeding. This filing was accepted by the FERC on November 15, 2006, and no requests for rehearing were filed.

On February 15, 2007, MISO filed documents with the FERC to establish a market-based, competitive ancillary services market. MISO contends that the filing will integrate operating reserves into MISO's existing day-ahead and real-time settlements process, incorporate opportunity costs into these markets, address scarcity pricing through the implementation of a demand curve methodology, foster demand response in the provision of operating reserves, and provide for various efficiencies and optimization with regard to generation dispatch. The filing also proposes amendments to existing documents to provide for the transfer of balancing functions from existing local balancing authorities to MISO. MISO will then carry out this reliability function as the NERC-certified balancing authority for the MISO region. MISO is targeting implementation for the second or third quarter of 2008. The FERC has established March 23, 2007, as the date for interested parties to submit comments addressing the filing. The filing has not yet been fully evaluated to assess its impact on our operations.

On February 16, 2007, the FERC issued a final rule that revises its decade-old open access transmission regulations and policies. The FERC explained that the final rule is intended to strengthen non-discriminatory access to the transmission grid, facilitate FERC enforcement, and provide for a more open and coordinated transmission planning process. The final rule will not be effective until 60 days after publication in the Federal Register. The final rule has not yet been fully evaluated to assess its impact on our operations.

Reliability Initiatives

We are proceeding with the implementation of the recommendations that 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) in late 2003 and early 2004, regarding enhancements to regional reliability that were to be completed subsequent to 2004. We 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. The FERC or other applicable government agencies and reliability entities, however, may take a different view as to recommended enhancements or may recommend additional enhancements in the future that could require additional, material expenditures.

As a result of outages experienced in JCP&L's service area in 2002 and 2003, the NJBPU had implemented reviews into JCP&L's service reliability. In 2004, the NJBPU adopted an MOU that set out specific tasks related to service reliability to be performed by JCP&L and a timetable for completion 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 an SRM who made recommendations on appropriate courses of action necessary to ensure system-wide reliability. The Stipulation also incorporates the Executive Summary and Recommendation portions of the final report of a focused audit of JCP&L's Planning and Operations and Maintenance programs and practices (Focused Audit). On February 11, 2005, JCP&L met with the DRA to discuss reliability improvements. The SRM completed his work and issued his final report to the NJBPU on June 1, 2006. JCP&L filed a comprehensive response to the NJBPU on July 14, 2006. JCP&L continues to file compliance reports reflecting activities associated with the MOU and Stipulation.

The EPACT provides for the creation of an ERO to establish and enforce reliability standards for the bulk power system, subject to FERC's review. On February 3, 2006, the FERC adopted a rule establishing certification requirements for the ERO, as well as regional entities envisioned to assume compliance monitoring and enforcement responsibility for the new reliability standards. The FERC issued an order on rehearing on March 30, 2006, providing certain clarifications and essentially affirming the rule.

The NERC has been preparing the implementation aspects of reorganizing its structure to meet the FERC's certification requirements for the ERO. The NERC made a filing with the FERC on April 4, 2006 to obtain certification as the ERO and to obtain FERC approval of pro forma delegation agreements with regional reliability organizations (regional entities). The new FERC rule referred to above, further provides for reorganizing regional entities that would replace the current regional councils and for rearranging their relationship with the ERO. The "regional entity" may be delegated authority by the ERO, subject to FERC approval, for compliance and enforcement of reliability standards adopted by the ERO and approved by the FERC. The ERO filing was noticed on April 7, 2006 and comments and reply comments were filed in May, June and July 2006. On July 20, 2006, the FERC certified the NERC as the ERO to implement the provisions of Section 215 of the Federal Power Act and directed the NERC to make compliance filings addressing governance and non-governance issues and the regional delegation agreements. On September 18, 2006 and October 18, 2006, NERC submitted compliance filings addressing the governance and non-governance issues identified in the FERC ERO Certification Order, dated July 20, 2006. On October 30, 2006, the FERC issued an order accepting most of NERC's governance filings. On January 18, 2007, the FERC issued an order largely accepting NERC's compliance filings addressing non-governance issues, subject to an additional compliance filing requirement.

On April 4, 2006, NERC also submitted a filing with the FERC seeking approval of mandatory reliability standards, as well as for approval with the relevant Canadian authorities. These reliability standards are based, with some modifications and additions, on the current NERC Version 0 reliability standards. The reliability standards filing was subsequently evaluated by the FERC on May 11, 2006, leading to the FERC staff's release of a preliminary assessment that cited many deficiencies in the proposed reliability standards. The NERC and industry participants filed comments in response to the Staff's preliminary assessment. The FERC held a technical conference on the proposed reliability standards on July 6, 2006. The FERC issued a NOPR on the proposed reliability standards on October 20, 2006. In the NOPR, the FERC proposed to approve 83 of the 107 reliability standards and directed NERC to make technical improvements to 62 of the 83 standards approved. The 24 standards that were not approved remain pending at the FERC awaiting further clarification and filings by the NERC and regional entities. The FERC also provided additional clarification within the NOPR regarding the proposed application of final standards and guidance with regard to technical improvements of the standards. On November 15, 2006, NERC submitted several revised reliability standards and three new proposed reliability standards. Interested parties were provided the opportunity to comment on the NOPR (including the revised standards submitted by NERC in November) by January 3, 2007. Numerous parties, including FirstEnergy, filed comments on the NOPR on January 3, 2007. Mandatory reliability standards enforceable with penalties are expected to be in place by the summer of 2007. In a separate order issued October 24, 2006, the FERC approved NERC's 2007 budget and business plan subject to certain compliance filings.

On November 29, 2006, NERC submitted an additional compliance filing with the FERC regarding the Compliance Monitoring and Enforcement Program (CMEP) along with the proposed Delegation Agreements between the ERO and the regional reliability entities. The FERC provided opportunity for interested parties to comment on the CMEP by January 10, 2007. We, as well as other parties, moved to intervene and submitted responsive comments on January 10, 2007. This filing is pending before the FERC.

The ECAR, Mid-Atlantic Area Council, and Mid-American Interconnected Network reliability councils completed the consolidation of these regions into a single new regional reliability organization known as Reliability*First* Corporation. Reliability*First* began operations as a regional reliability council under NERC on January 1, 2006 and on November 29, 2006 filed a proposed Delegation Agreement with NERC to obtain certification consistent with the final rule as a "regional entity" under the ERO. All of our facilities are located within the Reliability*First* region.

On May 2, 2006, the NERC Board of Trustees adopted eight new cyber security standards that replaced interim standards put in place in the wake of the September 11, 2001 terrorist attacks, and thirteen additional reliability standards. The security standards became effective on June 1, 2006, and the remaining standards will become effective throughout 2006 and 2007. NERC filed these proposed standards with the FERC and relevant Canadian authorities for approval. The cyber security standards were not included in the October 20, 2006 NOPR and are being addressed in a separate FERC docket. On December 11, 2006, the FERC Staff provided its preliminary assessment of these proposed mandatory reliability standards and again cited various deficiencies in the proposed standards, providing interested parties with the opportunity to comment on the assessment by February 12, 2007.

We believe that we are in compliance with all current NERC reliability standards. However, based upon a review of the October 20, 2006 NOPR, it appears that the FERC will adopt more strict reliability standards than those contained in the current NERC standards. The financial impact of complying with the new standards cannot be determined at this time. However, the EPACT required that all prudent costs incurred to comply with the new reliability standards be recovered in rates. If we are unable to meet the reliability standards for our bulk power system in the future, it could have a material adverse effect on our financial condition, results of operations and cash flows.

See Note 10 to the consolidated financial statements for a more detailed discussion of reliability initiatives.

ENVIRONMENTAL MATTERS

We accrue environmental liabilities only when it is probable that we have an obligation for such costs and can reasonably estimate the amount of such costs. Unasserted claims are reflected in our determination of environmental liabilities and are accrued in the period that they become both probable and reasonably estimable.

Clean Air Act Compliance

We are required to meet federally-approved SO_2 emissions 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. We believe that we are currently in compliance with this policy, but cannot predict what action the EPA may take in the future with respect to the interim enforcement policy.

The EPA Region 5 issued a Finding of Violation and NOV to the Bay Shore Power Plant dated June 15, 2006 alleging violations to various sections of the Clean Air Act. We have disputed those alleged violations based on our Clean Air Act permit, the Ohio SIP and other information provided at an August 2006 meeting with the EPA. The EPA has several enforcement options (administrative compliance order, administrative penalty order, and/or judicial, civil or criminal action) and has indicated that such option may depend on the time needed to achieve and demonstrate compliance with the rules alleged to have been violated.

We comply 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. NO_X 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 NO_X reductions at our facilities. The EPA's NO_X Transport Rule imposes uniform reductions of NO_X emissions (an approximate 85% reduction in utility plant NO_X 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 NO_X emissions are contributing significantly to ozone levels in the eastern United States. We believe our facilities are also complying with the NO_X budgets established under 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 fine particulate matter. In March 2005, the EPA finalized CAIR covering a total of 28 states (including Michigan, New Jersey, Ohio and Pennsylvania) and the District of Columbia based on proposed findings that air emissions from 28 eastern states and the District of Columbia significantly contribute to non-attainment of the NAAQS for fine particles and/or the "8-hour" ozone NAAQS in other states. CAIR provided each affected state until 2006 to develop implementing regulations to achieve additional reductions of NO_X and SO_2 emissions in two phases (Phase I in 2009 for NO_X, 2010 for SO_2 and Phase II in 2015 for both NO_X and SO_2). Our Michigan, Ohio and Pennsylvania fossil-fired generation facilities will be subject to caps on SO_2 and NO_X emissions, whereas its New Jersey fossil-fired generation facility will be subject to a cap on NO_X emissions only. According to the EPA, SO_2 emissions will be reduced by 45% (from 2003 levels) by 2010 across the states covered by the rule, with reductions reaching 73% (from 2003 levels) by 2015, capping SO_2 emissions in affected states to just 2.5 million tons annually. NO_X emissions will be reduced by 53% (from 2003 levels) by 2009 across the states covered by the rule, with reductions reaching 61% (from 2003 levels) by 2015, achieving a regional NO_X cap of 1.3 million tons annually. The future cost of compliance with these regulations may be substantial and will depend on how they are ultimately implemented by the states in which we 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. In March 2005, the EPA finalized CAMR, which provides for a cap-and-trade program to reduce mercury emissions from coal-fired power plants in two phases. Initially, mercury emissions will be capped nationally at 38 tons by 2010 (as a "co-benefit" from implementation of SO_2 and NO_X emission caps under the EPA's CAIR program). Phase II of the mercury cap-and-trade program will cap nationwide mercury emissions from coal-fired power plants at 15 tons per year by 2018. However, the final rules give states substantial discretion in developing rules to implement these programs. In addition, both CAIR and CAMR have been challenged in the United States Court of Appeals for the District of Columbia. Our future cost of compliance with these regulations may be substantial and will depend on how they are ultimately implemented by the states in which we operate affected facilities.

The model rules for both CAIR and CAMR contemplate an input-based methodology to allocate allowances to affected facilities. Under this approach, allowances would be allocated based on the amount of fuel consumed by the affected sources. We would prefer an output-based generation-neutral methodology in which allowances are allocated based on megawatts of power produced, allowing new and non-emitting generating facilities (including renewables and nuclear) to be entitled to their proportionate share of the allowances. Consequently, we will be disadvantaged if these model rules were implemented as proposed because our substantial reliance on non-emitting (largely nuclear) generation is not recognized under the input-based allocation.

Pennsylvania has submitted a new mercury rule for EPA approval that does not provide a cap and trade approach as in the CAMR, but rather follows a command and control approach imposing emission limits on individual sources. Pennsylvania's mercury regulation would deprive FES of mercury emission allowances that were to be allocated to the Mansfield Plant under the CAMR and that would otherwise be available for achieving FirstEnergy system-wide compliance. The future cost of compliance with these regulations, if approved and implemented, may be substantial.

W. H. Sammis Plant

In 1999 and 2000, the EPA issued NOV or compliance orders to nine utilities alleging violations of the Clean Air Act based on operation and maintenance of 44 power plants, including the W. H. Sammis Plant, which was owned at that time by OE and Penn. In addition, the DOJ filed eight civil complaints against various investor-owned utilities, including a complaint against OE and Penn in the U.S. District Court for the Southern District of Ohio. These cases are referred to as the New Source Review cases.

On March 18, 2005, OE and Penn announced that they had reached a settlement with the EPA, the DOJ and three states (Connecticut, New Jersey, and New York) that resolved all issues related to the New Source Review litigation. This settlement agreement, which is in the form of a consent decree, was approved by the Court on July 11, 2005, and requires reductions of NO_X and SO_2 emissions at the W. H. Sammis Plant and other FES coal-fired plants through the installation of pollution control devices and provides for stipulated penalties for failure to install and operate such pollution controls in accordance with that agreement. Consequently, if we fail to install such pollution control devices, for any reason, including, but not limited to, the failure of any third-party contractor to timely meet its delivery obligations for such devices, we could be exposed to penalties under the Sammis NSR Litigation consent decree. Capital expenditures necessary to complete requirements of the Sammis NSR Litigation are currently estimated to be $1.5 billion ($400 million of which is expected to be spent in 2007, with the largest portion of the remaining $1.1 billion expected to be spent in 2008 and 2009).

The Sammis NSR Litigation consent decree also requires us to spend up to $25 million toward environmentally beneficial projects, $14 million of which is satisfied by entering into 93 MW (or 23 MW if federal tax credits are not applicable) of wind energy purchased power agreements with a 20-year term. An initial 16 MW of the 93 MW consent decree obligation was satisfied during 2006.

On August 26, 2005, FGCO entered into an agreement with Bechtel Power Corporation under which Bechtel will engineer, procure, and construct air quality control systems for the reduction of SO_2 emissions. FGCO also entered into an agreement with B&W on August 25, 2006 to supply flue gas desulfurization systems for the reduction of SO_2 emissions. Selective Catalytic Reduction (SCR) systems for the reduction of NO_X emissions also are being installed at the W.H. Sammis Plant under a 1999 agreement with B&W.

OE and Penn agreed to pay a civil penalty of $8.5 million. Results for the first quarter of 2005 included the penalties paid by OE and Penn of $7.8 million and $0.7 million, respectively. OE and Penn also recognized liabilities in the first quarter of 2005 of $9.2 million and $0.8 million, respectively, for probable future cash contributions toward environmentally beneficial projects.

Climate Change

In December 1997, delegates to the United Nations' climate summit in Japan adopted an agreement, the Kyoto Protocol, to address global warming by reducing the amount of man-made GHG emitted by developed countries by 5.2% from 1990 levels between 2008 and 2012. The United States signed the Kyoto 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 GHG intensity – the ratio of emissions to economic output – by 18% through 2012. The EPACT established a Committee on Climate Change Technology to coordinate federal climate change activities and promote the development and deployment of GHG reducing technologies.

We 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 FirstEnergy is lower than many regional competitors due to its diversified generation sources which include low or non-CO_2 emitting gas-fired and nuclear generators.

Regulation of Hazardous Waste

Under NRC regulations, we must ensure that adequate funds will be available to decommission our nuclear facilities. As of December 31, 2006, we had approximately $1.4 billion invested in external trusts to be used for the decommissioning and environmental remediation of Davis-Besse, Beaver Valley and Perry. As part of the application to the NRC to transfer the ownership of these nuclear facilities to NGC, we agreed to contribute another $80 million to these trusts by 2010. Consistent with NRC guidance, utilizing a "real" rate of return on these funds of approximately 2% over inflation, these trusts are expected to exceed the minimum decommissioning funding requirements set by the NRC. Conservatively, these estimates do not include any rate of return that the trusts may earn over the 20-year plant useful life extensions that we plan to seek for these facilities.

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, 2006, based on estimates of the total costs of cleanup, the Companies' proportionate responsibility for such costs and the financial ability of other unaffiliated 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. Total liabilities of approximately $88 million have been accrued through December 31, 2006.

See Note 14(D) to the consolidated financial statements for further details and a complete discussion of environmental matters.

OTHER LEGAL PROCEEDINGS

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

Power Outages and Related Litigation

On August 14, 2003, various states and parts of southern Canada experienced widespread power outages. The outages affected approximately 1.4 million customers in our service area. The U.S. – Canada Power System Outage Task Force's final report in April 2004 on the outages concluded, among other things, that the problems leading to the outages began in our Ohio service area. Specifically, the final report concluded, 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 our 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 Web site (www.doe.gov). We believe 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. We remain convinced that the outages cannot be explained by events on any one utility's system. The final report contained 46 "recommendations to prevent or minimize the scope of future blackouts." Forty-five of those recommendations related to broad industry or policy matters while one, including subparts, related to activities the Task Force recommended be undertaken by FirstEnergy, MISO, PJM, ECAR, and other parties to correct the causes of the August 14, 2003 power outages. We implemented several initiatives, both prior to and since the August 14, 2003 power outages, which were independently verified by NERC as complete in 2004 and were consistent with these and other recommendations and collectively enhance the reliability of our electric system. Our implementation of these recommendations in 2004 included completion of the Task Force recommendations that were directed toward FirstEnergy. We are also 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. The FERC or other applicable government agencies and reliability coordinators may, however, take a different view as to recommended enhancements or may recommend additional enhancements in the future that could require additional material expenditures.

FirstEnergy companies also are defending five separate complaint cases before the PUCO relating to the August 14, 2003 power outages. Two cases were originally filed in Ohio State courts but were subsequently dismissed for lack of subject matter jurisdiction and further appeals were unsuccessful. In these cases the individual complainants—three in one case and four in the other—sought to represent others as part of a class action. The PUCO dismissed the class allegations, stating that its rules of practice do not provide for class action complaints. Three other pending PUCO complaint cases were filed by various insurance carriers either in their own name as subrogees or in the name of their insured. In each of these three cases, the carrier seeks reimbursement from various FirstEnergy companies (and, in one case, from PJM, MISO and American Electric Power Company, Inc., as well) for claims paid to insureds for damages allegedly arising as a result of the loss of power on August 14, 2003. The listed insureds in these cases, in many instances, are not customers of any FirstEnergy company. A sixth case involving the claim of a non-customer seeking reimbursement for losses incurred when its store was burglarized on August 14, 2003 was dismissed. On March 7, 2006, the PUCO issued a ruling, consolidating all of the pending outage cases for hearing; limiting the litigation to service-related claims by customers of the Ohio operating companies; dismissing FirstEnergy as a defendant; and ruling that the U.S.-Canada Power System Outage Task Force Report was not admissible into evidence. In response to a motion for rehearing filed by one of the claimants, the PUCO ruled on April 26, 2006 that the insurance company claimants, as insurers, may prosecute their claims in their name so long as they also identify the underlying insured entities and the Ohio utilities that provide their service. The PUCO denied all other motions for rehearing. The plaintiffs in each case have since filed amended complaints and the named FirstEnergy companies have answered and also have filed a motion to dismiss each action. On September 27, 2006, the PUCO dismissed certain parties and claims and otherwise ordered the complaints to go forward to hearing. The cases have been set for hearing on October 16, 2007.

On October 10, 2006, various insurance carriers refiled a complaint in Cuyahoga County Common Pleas Court seeking reimbursement for claims paid to numerous insureds who allegedly suffered losses as a result of the August 14, 2003 outages. All of the insureds appear to be non-customers. The plaintiff insurance companies are the same claimants in one of the pending PUCO cases. FirstEnergy, the Ohio Companies and Penn were served on October 27, 2006. On January 18, 2007, the Court granted the Companies' motion to dismiss the case. It is unknown whether or not the matter will be further appealed. No estimate of potential liability is available for any of these cases.

We were also named, along with several other entities, in a complaint in New Jersey State Court. The allegations against FirstEnergy were based, in part, on an alleged failure to protect the citizens of Jersey City from an electrical power outage. None of our subsidiaries serve customers in Jersey City. A responsive pleading has been filed. On April 28, 2006, the Court granted our motion to dismiss. The plaintiff has not appealed.

We are 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. Although we are unable to predict the impact of these proceedings, if FirstEnergy or our subsidiaries were ultimately determined to have legal liability in connection with these proceedings, it could have a material adverse effect on our financial condition, results of operations and cash flows.

Nuclear Plant Matters

On January 20, 2006, FENOC announced that it had entered into a deferred prosecution agreement with the U.S. Attorney's Office for the Northern District of Ohio and the Environmental Crimes Section of the Environment and Natural Resources Division of the DOJ related to FENOC's communications with the NRC during the fall of 2001 in connection with the reactor head issue at the Davis-Besse Nuclear Power Station. Under the agreement, the United States acknowledged FENOC's extensive corrective actions at Davis-Besse, FENOC's cooperation during investigations by the DOJ and the NRC, FENOC's pledge of continued cooperation in any related criminal and administrative investigations and proceedings, FENOC's acknowledgement of responsibility for the behavior of its employees, and its agreement to pay a monetary penalty. The DOJ agreed to refrain from seeking an indictment or otherwise initiating criminal prosecution of FENOC for all conduct related to the statement of facts attached to the deferred prosecution agreement, as long as FENOC remained in compliance with the agreement, which FENOC has done. FENOC paid a monetary penalty of $28 million (not deductible for income tax purposes) which reduced our earnings by $0.09 per common share in the fourth quarter of 2005. The deferred prosecution agreement expired on December 31, 2006.

On April 21, 2005, the NRC issued a NOV and proposed a $5.45 million civil penalty related to the degradation of the Davis-Besse reactor vessel head issue discussed above. We accrued $2 million for a potential fine prior to 2005 and accrued the remaining liability for the proposed fine during the first quarter of 2005. On September 14, 2005, FENOC filed its response to the NOV with the NRC. FENOC accepted full responsibility for the past failure to properly implement its boric acid corrosion control and corrective action programs. The NRC NOV indicated that the violations do not represent current licensee performance. We paid the penalty in the third quarter of 2005. On January 23, 2006, FENOC supplemented its response to the NRC's NOV on the Davis-Besse head degradation to reflect the deferred prosecution agreement that FENOC had reached with the DOJ.

On August 12, 2004, the NRC notified FENOC that it would increase its regulatory oversight of the Perry Nuclear Power Plant as a result of problems with safety system equipment over the preceding two years and the licensee's failure to take prompt and corrective action.

On April 4, 2005, the NRC held a public meeting to discuss FENOC's performance at the Perry Nuclear Power Plant as identified in the NRC's annual assessment letter to FENOC. Similar public meetings are held with all nuclear power plant licensees following issuance by the NRC of their annual assessments. According to the NRC, overall the Perry Nuclear Power Plant operated "in a manner that preserved public health and safety" even though it remained under heightened NRC oversight. During the public meeting and in the annual assessment, the NRC indicated that additional inspections will continue and that the plant must improve performance to be removed from the Multiple/Repetitive Degraded Cornerstone Column of the Action Matrix.

On September 28, 2005, the NRC sent a CAL to FENOC describing commitments that FENOC had made to improve the performance at the Perry Nuclear Power Plant and stated that the CAL would remain open until substantial improvement was demonstrated. The CAL was anticipated as part of the NRC's Reactor Oversight Process. In the NRC's 2005 annual assessment letter dated March 2, 2006 and associated meetings to discuss the performance of the Perry Nuclear Power Plant on March 14, 2006, the NRC again stated that the Perry Nuclear Power Plant continued to operate in a manner that "preserved public health and safety." However, the NRC also stated that increased levels of regulatory oversight would continue until sustained improvement in the performance of the facility was realized. If performance does not improve, the NRC has a range of options under the Reactor Oversight Process, from increased oversight to possible impact to the plant's operating authority. Although we are unable to predict the impact of the ultimate disposition of this matter, it could have a material adverse effect on our financial condition, results of operations and cash flows.

Other Legal Matters

On October 20, 2004, we were 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 now repealed PUHCA. Concurrent with this notification, we received a subpoena asking for background documents and documents related to the restatements and Davis-Besse issues. On December 30, 2004, we received a subpoena asking for documents relating to issues raised during the SEC's PUHCA examination. On August 24, 2005, additional information was requested regarding Davis-Besse-related disclosures, which has been provided. We have cooperated fully with the informal inquiry and continue to do so with the formal investigation.

On August 22, 2005, a class action complaint was filed against OE in Jefferson County, Ohio Common Pleas Court, seeking compensatory and punitive damages to be determined at trial based on claims of negligence and eight other tort counts alleging damages from W.H. Sammis Plant air emissions. The two named plaintiffs are also seeking injunctive relief to eliminate harmful emissions and repair property damage and the institution of a medical monitoring program for class members. On October 18, 2006, the Ohio Supreme Court transferred this case to a Tuscarawas County Common Pleas Court judge due to concerns over potential class membership by the Jefferson County Common Pleas Court.

JCP&L's bargaining unit employees filed a grievance challenging JCP&L's 2002 call-out procedure that required bargaining unit employees to respond to emergency power outages. On May 20, 2004, an arbitration panel concluded that the call-out procedure violated the parties' collective bargaining agreement. At the conclusion of the June 1, 2005 hearing, the arbitration panel decided not to hear testimony on damages and closed the proceedings. On September 9, 2005, the arbitration panel issued an opinion to award approximately $16 million to the bargaining unit employees. On February 6, 2006, a federal district court granted a union motion to dismiss, as premature, a JCP&L appeal of the award filed on October 18, 2005. JCP&L intends to re-file an appeal again in federal district court once the damages associated with this case are identified at an individual employee level. JCP&L recognized a liability for the potential $16 million award in 2005.

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

See Note 14(E) to the consolidated financial statements for further details and a complete discussion of these other legal proceedings.

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.

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.

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.

Pension and Other Postretirement Benefits Accounting

Our reported costs of providing non-contributory qualified and non-qualified defined pension benefits and post employment 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.

As of December 31, 2006, we adopted SFAS 158 which requires a net liability or asset to be recognized for the overfunded or underfunded status of our defined benefit pension and other postretirement benefit plans on the balance sheet and recognize changes in funded status in the year in which the changes occur through other comprehensive income. We will continue to apply the provisions of SFAS 87 and SFAS 106 in measuring plan assets and benefit obligations as of the balance sheet date and in determining the amount of net periodic benefit cost. Our underfunded status at December 31, 2006 is $637 million.

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. The assumed discount rate as of December 31, 2006 is 6.00% from 5.75% and 6.00% used as of December 31, 2005 and 2004, 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 2006, 2005 and 2004, our qualified pension plan assets actually earned $567 million or 12.5%, $325 million or 8.2% and $415 million or 11.1%, respectively. Our qualified pension costs in 2006, 2005 and 2004 were computed using an assumed 9.0% rate of return on plan assets which generated $396 million, $345 million and $286 million expected returns on plan assets, respectively. The 2006 expected return was based upon projections of future returns and our pension trust investment allocation of approximately 64% equities, 29% bonds, 5% real estate, 1% private equities and 1% cash. The gains or losses generated as a result of the difference between expected and actual returns on plan assets are deferred and amortized and will increase or decrease future net periodic pension expense, respectively.

Our pension and OPEB expense was $94 million in 2006 and $131 million in 2005. On January 2, 2007 FirstEnergy made a $300 million voluntary contribution to our pension plan. In addition during 2006, we amended our OPEB plan effective in 2008 to cap our monthly contribution for many of the retirees and their spouses receiving subsidized health care coverage. As a result of the $300 million voluntary contribution and the amendment to the OPEB plan effective in 2008, we expect the pension and OPEB costs for 2007 to be a credit of $94 million for FirstEnergy.

Pension expense in our non-qualified pension plans is expected to be approximately $21 million in 2007, compared to $21 million in 2006 and $16 million in 2005.

Health care cost trends continue to increase and will affect future OPEB costs. The 2006 and 2005 composite health care trend rate assumptions are approximately 9-11%, 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 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%	$13	$2	$15
Long-term return on assets	Decrease by 0.25%	$13	$1	$14
Health care trend rate	Increase by 1%	N/A	$6	$ 6

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 our 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). We use an effective interest method for amortizing the Ohio Companies' 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, we include 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. Amortization of deferred customer shopping incentives and interest costs are equal to the related revenue recovery that is recognized under the RCP (see Note 2(A)).

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.

Asset Retirement Obligations

In accordance with SFAS 143 and FIN 47, we recognize an ARO for the future decommissioning of our nuclear power plants and future remediation of other environmental liabilities associated with all of our long-lived assets. The ARO liability represents an estimate of the fair value of our current obligation related to nuclear decommissioning and the retirement or remediation of environmental liabilities of other assets. A fair value measurement inherently involves uncertainty in the amount and timing of settlement of the liability. We use an expected cash flow approach to measure the fair value of the nuclear decommissioning and environmental remediation 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, settlement based on an extended license term and expected remediation dates.

Income Taxes

We record 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.

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 2006 with no impairment indicated. As discussed in Note 10 to the consolidated financial statements, the PPUC issued its order on January 11, 2007 related to the comprehensive rate filing made by Met-Ed and Penelec on April 10, 2006. Prior to issuing the order, the PPUC conducted an informal, nonbinding polling of Commissioners at its public meeting on December 21, 2006 that indicated that the rate increase ultimately granted could be substantially lower than the amounts requested. As a result of the polling, FirstEnergy determined that an interim review of goodwill for its Regulated Services segment would be required. No impairment was indicated as a result of that review.

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 2005, MYR qualified as an asset held for sale in accordance with SFAS 144. As a result, in the fourth quarter of 2005, the goodwill of MYR was retested for impairment, resulting in a non-cash charge of $9 million (there was no corresponding income tax benefit).

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 159 – "The Fair Value Option for Financial Assets and Financial Liabilities – Including an amendment of FASB Statement No. 115"

In February 2007, the FASB issued SFAS 159, which provides companies with an option to report selected financial assets and liabilities at fair value. The Standard requires companies to provide additional information that will help investors and other users of financial statements to more easily understand the effect of the company's choice to use fair value on its earnings. The Standard also requires companies to display the fair value of those assets and liabilities for which the company has chosen to use fair value on the face of the balance sheet. This guidance does not eliminate disclosure requirements included in other accounting standards, including requirements for disclosures about fair value measurements included in SFAS 157, *Fair Value Measurements*, and SFAS 107, *Disclosures about Fair Value of Financial Instruments*. We are currently evaluating the impact of this Statement on our financial statements.

FSP EITF 00-19-2 – "Accounting for Registration Payment Arrangements"

In December 2006, the FASB issued FSP EITF 00-19-2, which addresses an issuer's accounting for registration payment arrangements. This guidance specifies that the contingent obligation to make future payments or otherwise transfer consideration under a registration payment arrangement, whether issued as a separate agreement or included as a provision of a financial instrument or other agreement, should be separately recognized and measured in accordance with SFAS 5, *Accounting for Contingencies*. This FSP shall be effective immediately for registration payment arrangements and the financial instruments subject to those arrangements that are entered into or modified subsequent to the date of issuance of this FSP. For arrangements that were entered into prior to the issuance of this FSP, this guidance shall be effective for financial statements issued for fiscal years beginning after December 15, 2006, and interim periods within those fiscal years. We do not expect this FSP to have a material effect on our financial statements.

EITF 06-5 – "Accounting for Purchases of Life Insurance-Determining the Amount That Could Be Realized in Accordance with FASB Technical Bulletin No. 85-4, Accounting for Purchases of Life Insurance"

In September 2006, the EITF reached a consensus on Issue 06-5 concluding that a policyholder should consider any additional amounts included in the contractual terms of the policy in determining the amount that could be realized under the insurance contract. Contractual limitations should be considered when determining the realizable amounts. Amounts that are recoverable by the policyholder at the discretion of the insurance company should be excluded from the amount that could be realized. Recoverable amounts in periods beyond one year from the surrender of the policy should be discounted in accordance with APB Opinion No. 21, "Interest on Receivables and Payables." Consensus was also reached that a policyholder should determine the amount that could be realized under the insurance contract assuming the surrender of an individual-life by individual-life policy (or certificate by certificate in a group policy). Any amount that would ultimately be realized by the policyholder upon the assumed surrender of the final policy (or final certificate) should be included in the amount that could be realized under the insurance contract. The EITF also concluded that a policyholder should not discount the cash surrender value component of the amount that could be realized when contractual restrictions on the ability to surrender a policy exist. However, if the contractual limitations prescribe that the cash surrender value component of the amount that could be realized is a fixed amount, then the amount that could be realized should be discounted in accordance with APB Opinion No. 21. This Issue is effective for fiscal years beginning after December 15, 2006. We do not expect this EITF to have a material impact on our financial statements.

SFAS 157 – "Fair Value Measurements"

In September 2006, the FASB issued SFAS 157 that establishes how companies should measure fair value when they are required to use a fair value measure for recognition or disclosure purposes under GAAP. This Statement addresses the need for increased consistency and comparability in fair value measurements and for expanded disclosures about fair value measurements. The key changes to current practice are: (1) the definition of fair value which focuses on an exit price rather than entry price; (2) the methods used to measure fair value such as emphasis that fair value is a market-based measurement, not an entity-specific measurement, as well as the inclusion of an adjustment for risk, restrictions and credit standing; and (3) the expanded disclosures about fair value measurements. This Statement is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those years. We are currently evaluating the impact of this Statement on our financial statements.

FSP FIN 46(R)-6 – "Determining the Variability to Be Considered in Applying FASB interpretation No. 46(R)"

In April 2006, the FASB issued FSP FIN 46(R)-6 that addresses how a reporting enterprise should determine the variability to be considered in applying FASB interpretation No. 46 (revised December 2003). We adopted FIN 46(R) in the first quarter of 2004, consolidating VIEs when we or one of our subsidiaries are determined to be the VIE's primary beneficiary. The variability that is considered in applying interpretation 46(R) affects the determination of (a) whether the entity is a VIE; (b) which interests are variable interests in the entity; and (c) which party, if any, is the primary beneficiary of the VIE. This FSP states that the variability to be considered shall be based on an analysis of the design of the entity, involving two steps:

Step 1: Analyze the nature of the risks in the entity

Step 2: Determine the purpose(s) for which the entity was created and determine the variability the entity is designed to create and pass along to its interest holders.

After determining the variability to consider, the reporting enterprise can determine which interests are designed to absorb that variability. The guidance in this FSP is applied prospectively to all entities (including newly created entities) with which that enterprise first becomes involved and to all entities previously required to be analyzed under interpretation 46(R) when a reconsideration event has occurred after July 1, 2006. Our adoption of this Statement had no impact on our financial statements.

FIN 48 – "Accounting for Uncertainty in Income Taxes – an interpretation of FASB Statement No. 109"

In June 2006, the FASB issued FIN 48 which clarifies the accounting for uncertainty in income taxes recognized in an enterprise's financial statements in accordance with FASB Statement No. 109, "Accounting for Income Taxes." This interpretation prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken on a tax return. This interpretation also provides guidance on derecognition, classification, interest, penalties, accounting in interim periods, disclosure and transition. The evaluation of a tax position in accordance with this interpretation will be a two-step process. The first step will determine if it is more likely than not that a tax position will be sustained upon examination and should therefore be recognized. The second step will measure a tax position that meets the more likely than not recognition threshold to determine the amount of benefit to recognize in the financial statements. This interpretation is effective for fiscal years beginning after December 15, 2006. We do not expect this Statement to have a material impact on our financial statements.

Consolidated Statements Of Income

For the Years Ended December 31,	2006	2005	2004
		(In millions, except per share amounts)	
REVENUES:			
Electric utilities	$10,007	$9,703	$8,860
Unregulated businesses	1,494	1,655	2,740
Total revenues*	11,501	11,358	11,600
EXPENSES:			
Fuel and purchased power	4,253	4,011	4,469
Other operating expenses	2,965	3,103	2,910
Provision for depreciation	596	588	585
Amortization of regulatory assets	861	1,281	1,166
Deferral of new regulatory assets	(500)	(405)	(257)
General taxes	720	713	678
Total expenses	8,895	9,291	9,551
OPERATING INCOME	2,606	2,067	2,049
OTHER INCOME (EXPENSE):			
Investment income	149	217	205
Interest expense	(721)	(660)	(671)
Capitalized interest	26	19	26
Subsidiaries' preferred stock dividends	(7)	(15)	(21)
Total other expense	(553)	(439)	(461)
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	2,053	1,628	1,588
INCOME TAXES	795	749	681
INCOME FROM CONTINUING OPERATIONS	1,258	879	907
Discontinued operations (net of income tax benefits of $2 million, $4 million, and $7 million, respectively) (Note 2(J))	(4)	12	(29)
INCOME BEFORE CUMULATIVE EFFECT OF A CHANGE IN ACCOUNTING PRINCIPLE	1,254	891	878
Cumulative effect of a change in accounting principle (net of income tax benefit of $17 million) (Note 2(K))	–	(30)	–
NET INCOME	$ 1,254	$ 861	$ 878
BASIC EARNINGS PER SHARE OF COMMON STOCK:			
Income from continuing operations	$ 3.85	$ 2.68	$ 2.77
Discontinued operations (Note 2(J))	(0.01)	0.03	(0.09)
Cumulative effect of a change in accounting principle (Note 2(K))	–	(0.09)	–
Net earnings per basic share	$ 3.84	$ 2.62	$ 2.68
WEIGHTED AVERAGE NUMBER OF BASIC SHARES OUTSTANDING	324	328	327
DILUTED EARNINGS PER SHARE OF COMMON STOCK:			
Income from continuing operations	$ 3.82	$ 2.67	$ 2.76
Discontinued operations (Note 2(J))	(0.01)	0.03	(0.09)
Cumulative effect of a change in accounting principle (Note 2(K))	–	(0.09)	–
Net earnings per diluted share	$ 3.81	$ 2.61	$ 2.67
WEIGHTED AVERAGE NUMBER OF DILUTED SHARES OUTSTANDING	327	330	329

** Includes $400 million, $395 million and $376 million of excise tax collections in 2006, 2005 and 2004, respectively.*

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

Consolidated Balance Sheets

As of December 31,	2006	2005
	(In millions)	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 90	$ 64
Receivables-		
Customers (less accumulated provisions of $43 million and $38 million, respectively, for uncollectible accounts)	1,135	1,293
Other (less accumulated provisions of $24 million and $27 million, respectively, for uncollectible accounts)	132	205
Materials and supplies, at average cost	577	518
Prepayments and other	149	237
	2,083	2,317
PROPERTY, PLANT AND EQUIPMENT:		
In service	24,105	22,893
Less–Accumulated provision for depreciation	10,055	9,792
	14,050	13,101
Construction work in progress	617	897
	14,667	13,998
INVESTMENTS:		
Nuclear plant decommissioning trusts	1,977	1,752
Investments in lease obligation bonds (Note 6)	811	890
Other	746	709
	3,534	3,351
DEFERRED CHARGES AND OTHER ASSETS:		
Goodwill	5,898	6,010
Regulatory assets	4,441	4,486
Prepaid pension costs (Note 3)	–	1,023
Other	573	656
	10,912	12,175
	$31,196	$31,841
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Currently payable long-term debt	$ 1,867	$ 2,043
Short-term borrowings (Note 13)	1,108	731
Accounts payable	726	727
Accrued taxes	598	800
Other	956	1,152
	5,255	5,453
CAPITALIZATION (See Consolidated Statements of Capitalization):		
Common stockholders' equity	9,035	9,188
Preferred stock of consolidated subsidiaries	–	184
Long-term debt and other long-term obligations	8,535	8,155
	17,570	17,527
NONCURRENT LIABILITIES:		
Accumulated deferred income taxes	2,740	2,726
Asset retirement obligations	1,190	1,126
Power purchase contract loss liability	1,182	1,226
Retirement benefits	944	1,316
Lease market valuation liability	767	851
Other	1,548	1,616
	8,371	8,861
COMMITMENTS, GUARANTEES AND CONTINGENCIES (Notes 6 and 14)		
	$31,196	$31,841

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

Consolidated Statements Of Capitalization

As of December 31, COMMON STOCKHOLDERS' EQUITY: *(Dollars in millions)*	2006	2005
Common stock, $0.10 par value -authorized 375,000,000 shares-319,205,517 and 329,836,276 shares outstanding, respectively	$ 32	$ 33
Other paid-in capital	6,466	7,043
Accumulated other comprehensive loss (Note 2(I))	(259)	(20)
Retained earnings (Note 11(A))	2,806	2,159
Unallocated employee stock ownership plan common stock-521,818 and 1,444,796 shares, respectively (Note 4(B))	(10)	(27)
Total common stockholders' equity	9,035	9,188

PREFERRED STOCK OF CONSOLIDATED SUBSIDIARIES (Note 11(B)):	Number of Shares Outstanding (Thousands) 2006	2005	2006	2005
Ohio Edison Company-				
Cumulative, $100 par value-authorized 6,000,000 shares	–	610	$ –	$ 61
Pennsylvania Power Company-				
Cumulative, $100 par value-authorized 1,200,000 shares	–	141	–	14
Toledo Edison Company-				
Cumulative, $100 par value-authorized 3,000,000 shares	–	310	–	31
Cumulative, $25 par value-authorized 12,000,000 shares	–	2,600	–	65
Total Toledo Edison Company	–	2,910	–	96
Jersey Central Power & Light Company-				
Cumulative, $100 stated value-authorized 15,600,000 shares	–	125	–	13
Total preferred stock of consolidated subsidiaries			–	184

LONG-TERM DEBT AND OTHER LONG-TERM OBLIGATIONS (Note 11(C)): (Interest rates reflect weighted average rates)

	FIRST MORTGAGE BONDS			SECURED NOTES			UNSECURED NOTES			TOTAL	
	%	2006	2005	%	2006	2005	%	2006	2005	2006	2005
Ohio Edison Company-											
Due 2006-2011	–	$ –	$ –	7.24	$8	$113	4.79	$331	$331		
Due 2012-2016	–	–	–	–	–	67	6.04	400	150		
Due 2017-2021	–	–	–	–	–	60	–	–	–		
Due 2027-2031	–	–	–	4.15	120	250	–	–	–		
Due 2032-2036	–	–	–	–	–	135	6.88	350	–		
Total-Ohio Edison		–	–		128	625		1,081	481	$1,209	$1,106
Cleveland Electric Illuminating Company-											
Due 2006-2011	6.86	125	125	6.47	351	399	–	–	28		
Due 2012-2016	–	–	–	–	–	40	5.72	379	379		
Due 2017-2021	–	–	–	7.32	433	506	–	–	–		
Due 2027-2031	–	–	–	5.38	6	29	9.00	103	103		
Due 2032-2036	–	–	–	3.94	54	219	5.95	300	–		
Total-Cleveland Electric		125	125		844	1,193		782	510	1,751	1,828
Toledo Edison Company-											
Due 2006-2011	–	–	–	7.13	30	30	–	–	54		
Due 2022-2026	–	–	–	–	–	67	–	–	–		
Due 2027-2031	–	–	–	5.90	14	14	–	–	–		
Due 2032-2036	–	–	–	4.10	45	127	–	–	–		
Due 2037-2041	–	–	–	–	–	–	6.15	300	–		
Total-Toledo Edison		–	–		89	238		300	54	389	292
Pennsylvania Power Company-											
Due 2006-2011	9.74	5	6	–	–	54	–	–	15		
Due 2012-2016	9.74	5	5	5.40	1	1	–	–	–		
Due 2017-2021	9.74	3	3	–	–	39	–	–	–		
Due 2022-2026	7.63	6	6	–	–	–	–	–	–		
Due 2027-2031	–	–	–	5.38	2	8	–	–	–		
Total-Penn Power		19	20		3	102		–	15	22	137

Consolidated Statements Of Capitalization (Cont'd)

As of December 31, *(Dollars in millions)*

LONG-TERM DEBT AND OTHER LONG-TERM OBLIGATIONS (Cont'd) (Interest rates reflect weighted average rates)

	FIRST MORTGAGE BONDS			SECURED NOTES			UNSECURED NOTES			TOTAL	
	%	2006	2005	%	2006	2005	%	2006	2005	2006	2005
Jersey Central Power & Light Company-											
Due 2006-2011	–	$ –	$40	5.28	$152	$267	–	$ –	$ –		
Due 2012-2016	7.10	12	12	5.71	493	432	–	–	–		
Due 2017-2021	–	–	–	5.12	235	165	–	–	–		
Due 2022-2026	7.09	275	275	–	–	–	–	–	–		
Due 2032-2036	–	–	–	6.40	200	–	–	–	–		
Total-Jersey Central		287	327		1,080	864		–	–	$ 1,367	$ 1,191
Metropolitan Edison Company-											
Due 2006-2011	–	–	–	–	–	–	4.94	150	250		
Due 2012-2016	–	–	–	–	–	–	4.90	400	400		
Due 2017-2021	–	–	–	–	–	–	3.96	28	28		
Due 2027-2031	5.95	14	14	–	–	–	–	–	–		
Total-Metropolitan Edison		14	14		–	–		578	678	592	692
Pennsylvania Electric Company-											
Due 2006-2011	5.35	24	24	–	–	–	6.55	135	135		
Due 2012-2016	–	–	–	–	–	–	5.13	150	150		
Due 2017-2021	–	–	–	–	–	–	6.25	145	145		
Due 2022-2026	–	–	–	–	–	–	4.11	25	25		
Total-Pennsylvania Electric		24	24		–	–		455	455	479	479
FirstEnergy Corp.-											
Due 2006-2011	–	–	–	–	–	–	6.45	1,500	2,500		
Due 2027-2031	–	–	–	–	–	–	7.38	1,500	1,500		
Total-FirstEnergy		–	–		–	–		3,000	4,000	3,000	4,000
Bay Shore Power	–	–	–	6.25	130	134	–	–	–	130	134
Facilities Services Group	–	–	–	–	–	4	–	–	–	–	4
FirstEnergy Generation	–	–	–	–	–	–	4.55	624	58	624	58
FirstEnergy Nuclear Generation	–	–	–	–	–	–	4.61	861	270	861	270
FirstEnergy Properties	–	–	–	–	–	9	–	–	–	–	9
Total		469	510		2,274	3,169		7,681	6,521	10,424	10,200
Capital lease obligations										4	8
Net unamortized discount on debt										(26)	(10)
Long-term debt due within one year										(1,867)	(2,043)
Total long-term debt and other long-term obligations										8,535	8,155
TOTAL CAPITALIZATION										$17,570	$17,527

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

Consolidated Statements Of Common Stockholders' Equity

	Comprehensive Income	Number of Shares	Par Value	Other Paid-In Capital	Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Unallocated ESOP Common Stock
				(Dollars in millions)			
Balance, January 1, 2004		329,836,276	$33	$7,063	$(353)	$1,605	$(58)
Net income	$ 878					878	
Minimum liability for unfunded retirement benefits, net of $5 million of income tax benefits	(6)				(6)		
Unrealized gain on derivative hedges, net of $10 million of income taxes	19				19		
Unrealized gain on investments, net of $20 million of income taxes	27				27		
Comprehensive income	$ 918						
Stock options exercised				(24)			
Allocation of ESOP shares				17			15
Common stock dividends declared in 2004 payable in 2005						(135)	
Cash dividends declared on common stock						(491)	
Balance, December 31, 2004		329,836,276	33	7,056	(313)	1,857	(43)
Net income	$ 861					861	
Minimum liability for unfunded retirement benefits, net of $208 million of income taxes	295				295		
Unrealized gain on derivative hedges, net of $9 million of income taxes	14				14		
Unrealized loss on investments, net of $15 million of income tax benefits	(16)				(16)		
Comprehensive income	$1,154						
Stock options exercised				(41)			
Allocation of ESOP shares				22			16
Restricted stock units				6			
Cash dividends declared on common stock						(559)	
Balance, December 31, 2005		329,836,276	33	7,043	(20)	2,159	(27)
Net income	$1,254					1,254	
Unrealized gain on derivative hedges, net of $10 million of income taxes	19				19		
Unrealized gain on investments, net of $40 million of income taxes	69				69		
Comprehensive income	$1,342						
Net liability for unfunded retirement benefits due to the implementation of SFAS 158, net of $292 million of income tax benefits					(327)		
Redemption premiums on preferred stock						(9)	
Stock options exercised				(28)			
Allocation of ESOP shares				33			17
Restricted stock units				11			
Stock based compensation				6			
Repurchase of common stock		(10,630,759)	(1)	(599)			
Cash dividends declared on common stock						(598)	
Balance, December 31, 2006		319,205,517	$32	$6,466	$(259)	$2,806	$(10)

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

Consolidated Statements Of Preferred Stock

	Not Subject to Mandatory Redemption		Subject to Mandatory Redemption	
	Number of Shares	Par or Stated Value	Number of Shares	Par or Stated Value
	(Dollars in millions)			
Balance, January 1, 2004	6,209,699	$335	185,000	$19
Redemptions-				
7.625% Series			(7,500)	(1)
$7.35 Series C			(10,000)	(1)
Balance, December 31, 2004	6,209,699	335	167,500	17
Redemptions-				
7.750% Series	(250,000)	(25)		
$7.40 Series A	(500,000)	(50)		
Adjustable Series L	(474,000)	(46)		
Adjustable Series A	(1,200,000)	(30)		
7.625% Series			(127,500)	(13)
$7.35 Series C			(40,000)	(4)
Balance, December 31, 2005	3,785,699	184	–	–
Redemptions-				
3.90% Series	(152,510)	(15)		
4.40% Series	(176,280)	(18)		
4.44% Series	(136,560)	(14)		
4.56% Series	(144,300)	(14)		
4.24% Series	(40,000)	(4)		
4.25% Series	(41,049)	(4)		
4.64% Series	(60,000)	(6)		
$4.25 Series	(160,000)	(16)		
$4.56 Series	(50,000)	(5)		
$4.25 Series	(100,000)	(10)		
$2.365 Series	(1,400,000)	(35)		
Adjustable Series B	(1,200,000)	(30)		
4.00% Series	(125,000)	(13)		
Balance, December 31, 2006	–	$ –	–	$ –

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

Consolidated Statements Of Cash Flows

For the Years Ended December 31,	2006	2005	2004
		(In millions)	
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	$1,254	$ 861	$ 878
Adjustments to reconcile net income to net cash from operating activities-			
Provision for depreciation	596	588	585
Amortization of regulatory assets	861	1,281	1,166
Deferral of new regulatory assets	(500)	(405)	(257)
Nuclear fuel and lease amortization	90	90	96
Deferred purchased power and other costs	(445)	(384)	(451)
Deferred income taxes and investment tax credits, net	159	154	258
Investment impairment (Note 2(H))	14	6	28
Cumulative effect of a change in accounting principle	–	30	–
Deferred rents and lease market valuation liability	(113)	(104)	(84)
Accrued compensation and retirement benefits	193	90	156
Tax refunds related to pre-merger period	–	18	–
Commodity derivative transactions, net	24	6	18
Loss (gain) on asset sales	(49)	(35)	20
Loss (income) from discontinued operations (Note 2(J))	4	(12)	29
Cash collateral, net	(77)	196	(63)
Pension trust contribution	–	(500)	(500)
Decrease (increase) in operating assets-			
Receivables	105	(87)	154
Materials and supplies	(25)	(32)	(9)
Prepayments and other current assets	3	3	47
Increase (decrease) in operating liabilities-			
Accounts payable	99	32	(111)
Accrued taxes	(175)	150	(5)
Accrued interest	7	(6)	(42)
Electric service prepayment programs	(64)	208	(18)
Other	(22)	72	(3)
Net cash provided from operating activities	1,939	2,220	1,892
CASH FLOWS FROM FINANCING ACTIVITIES:			
New Financing-			
Long-term debt	2,739	721	961
Short-term borrowings, net	386	561	–
Redemptions and Repayments-			
Common stock	(600)	–	–
Preferred stock	(193)	(170)	(2)
Long-term debt	(2,536)	(1,424)	(1,572)
Short-term borrowings, net	–	–	(351)
Net controlled disbursement activity	(27)	(18)	(2)
Stock-based compensation tax benefit	13	–	–
Common stock dividend payments	(586)	(546)	(491)
Net cash used for financing activities	(804)	(876)	(1,457)
CASH FLOWS FROM INVESTING ACTIVITIES:			
Property additions	(1,315)	(1,208)	(846)
Proceeds from asset sales	162	104	223
Proceeds from certificates of deposits	–	–	278
Nonutility generation trusts contributions	–	–	(51)
Proceeds from nuclear decommissioning trust fund sales	1,571	1,715	1,131
Investments in nuclear decommissioning trust funds	(1,586)	(1,816)	(1,232)
Cash investments and restricted funds (Note 5)	121	(42)	27
Other	(62)	(86)	(26)
Net cash used for investing activities	(1,109)	(1,333)	(496)
Net increase (decrease) in cash and cash equivalents	26	11	(61)
Cash and cash equivalents at beginning of year	64	53	114
Cash and cash equivalents at end of year	$ 90	$ 64	$ 53
SUPPLEMENTAL CASH FLOW INFORMATION:			
Cash Paid During the Year-			
Interest (net of amounts capitalized)	$ 656	$ 665	$ 704
Income taxes	$ 688	$ 406	$ 512

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

Notes To Consolidated Financial 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 subsidiaries FGCO and NGC, and FESC.

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 disclosure of contingent assets and liabilities. Actual results could differ from these estimates. The reported results of operations are not indicative of results of operations for any future period.

FirstEnergy and its subsidiaries consolidate all majority-owned subsidiaries over which they exercise control and, when applicable, entities for which they have a controlling financial interest. Intercompany transactions and balances are eliminated in consolidation. FirstEnergy consolidates a VIE (see Note 7) when it is determined to be the VIE's primary beneficiary. Investments in non-consolidated affiliates over which FirstEnergy and its subsidiaries have the ability to exercise significant influence, but not control (20-50% owned companies, joint ventures and partnerships) are accounted for under the equity method. Under the equity method, the interest in the entity is reported as an investment in the Consolidated Balance Sheets and the percentage share of the entity's earnings is reported in the Consolidated Statements of Income.

Certain prior year amounts have been reclassified to conform to the current year presentation. Certain businesses divested in 2006 have been classified as discontinued operations on the Consolidated Statements of Income (see Note 2(J)). As discussed in Note 16, segment reporting in 2005 and 2004 was reclassified to conform to the 2006 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 since 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 SFA S71 no longer meets those requirements, previously recorded net regulatory assets are removed from the balance sheet in accordance with the guidance in SFAS 101.

In Ohio, Pennsylvania and New Jersey, 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 Companies and ATSI 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. As of December 31, 2006, regulatory assets that do not earn a current return totaled approximately $200 million, consisting of Penelec NUG stranded costs ($70 million), JCP&L outage funding costs ($32 million), post employment benefit costs ($20 million) and reliability costs ($14 million).

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

	2006	2005
	(In millions)	
Regulatory transition costs	$3,266	$3,576
Customer shopping incentives	603	884
Customer receivables for future income taxes	217	217
Societal benefits charge	11	29
Loss on reacquired debt	43	41
Employee postretirement benefit costs	47	55
Nuclear decommissioning, decontamination and spent fuel disposal costs	(145)	(126)
Asset removal costs	(168)	(365)
Property losses and unrecovered plant costs	19	29
MISO/PJM transmission costs	213	91
Fuel costs – RCP	113	–
Distribution costs – RCP	155	–
Other	67	55
Total	$4,441	$4,486

The Ohio Companies have been deferring customer shopping incentives and interest costs (Extended RTC) as new regulatory assets in accordance with the prior transition and rate stabilization plans. As a result of the RCP approved in January 2006, the Extended RTC balances (OE – $325 million, CEI – $427 million, TE – $132 million, as of December 31, 2005) were reduced on January 1, 2006 by $75 million for OE, $85 million for CEI and $45 million for TE by accelerating the application of those amounts of each respective company's accumulated cost of removal regulatory liability against the Extended RTC balances. In accordance with the RCP, the recovery periods for the aggregate of the regulatory transition costs and the Extended RTC amounts were adjusted so that recovery of these aggregate amounts through each company's RTC rate component began on January 1, 2006, with full recovery expected to be completed for OE and TE as of December 31, 2008. CEI's recovery of its regulatory transition costs is projected to be completed by April 2009 at which time recovery of its Extended RTC will begin, with recovery estimated to be completed as of December 31, 2010. At the end of their respective recovery periods, any remaining unamortized regulatory transition costs and Extended RTC balances will be eliminated, first, by applying any remaining cost of removal regulatory liability balances; any remaining regulatory transition costs and Extended RTC balances would be written off. The RCP allows the Ohio Companies to defer and capitalize certain distribution costs during the period January 1, 2006 through December 31, 2008, not to exceed $150 million in each of the years 2006, 2007 and 2008. These deferrals will be recovered in distribution rates effective on or after January 1, 2009. In addition, the RCP allows the Ohio Companies to defer certain increased fuel costs above the amount collected through a PUCO approved fuel recovery mechanism. See Note 10(B) for further discussion of the recovery of the shopping incentives and the new cost deferrals.

Transition Cost Amortization

OE, CEI and TE amortize transition costs (see Regulatory Matters – Ohio) using the effective interest method. Extended RTC amortization is equal to the related revenue recovery that is recognized. The following table provides the estimated net amortization of regulatory transition costs and Extended RTC amounts (including associated carrying charges) under the RCP for the period 2007 through 2010:

Amortization Period	OE	CEI	TE	Total Ohio
		(In millions)		
2007	$179	$108	$ 93	$ 380
2008	208	124	119	451
2009	–	216	–	216
2010	–	273	–	273
Total Amortization	$387	$721	$212	$1,320

Total regulatory transition costs as of December 31, 2006 were $3.3 billion, of which approximately $2.2 billion and $285 million apply to JCP&L and Met-Ed, respectively. JCP&L and Met-Ed's regulatory transition costs include deferral of above-market costs from power supplied by NUGs of $1.2 billion for JCP&L being recovered through BGS and MTC revenues, and $134 million for Met-Ed recovered through CTC revenues. The liability for JCP&L's projected above-market NUG costs and corresponding regulatory asset 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 10.

(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 historical customer usage, load profiles, estimated weather impacts, customer shopping activity 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, 2006 with respect to any particular segment of FirstEnergy's customers. Total customer receivables were $1.1 billion (billed – $650 million and unbilled – $485 million) and $1.3 billion (billed – $841 million and unbilled – $452 million) as of December 31, 2006 and 2005, respectively.

(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 PLR requirements in Pennsylvania. In conjunction with FirstEnergy's dedication of its Beaver Valley Plant to PJM on January 1, 2005, FES began accounting for purchase and sale transactions in the PJM Market based on its net hourly position — recording each hour as either an energy purchase or an energy sale in the Consolidated Statements of Income relating to the Power Supply Management Services segment. Hourly energy positions are aggregated to recognize gross purchases and sales for the month. This revised method of accounting, which has no impact on net income, is consistent with the practice of other energy companies that have dedicated generating capacity in PJM and correlates with PJM's scheduling and reporting of hourly energy transactions. FES also applies the net hourly methodology to purchase and sale transactions in MISO's energy market, which became active on April 1, 2005.

For periods prior to January 1, 2005, FirstEnergy did not have substantial generating capacity in PJM and as such, FES recognized purchases and sales in the PJM Market by recording each discrete transaction. Under those transactions, FES would often buy a specific quantity of energy at a certain location in PJM and simultaneously sell a specific quantity of energy at a different location. Physical delivery occurred and the risks and rewards of ownership transferred with each transaction. FES accounted for those transactions on a gross basis in accordance with EITF 99-19. The recognition of those transactions on a net basis in prior periods would have no impact on net income, but would have reduced both wholesale revenue and purchased power expense by $1.1 billion in 2004.

(E) EARNINGS PER SHARE OF COMMON STOCK-

Basic earnings per share of common stock is computed using the weighted average of actual common shares outstanding during the respective period as the denominator. The denominator for diluted earnings per share of common stock 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. The pool of stock-based compensation tax benefits is calculated in accordance with SFAS 123(R). On August 10, 2006, FirstEnergy repurchased 10.6 million shares, approximately 3.2%, of its outstanding common stock through an accelerated share repurchase program (see Note 14(C)). The initial purchase price was $600 million, or $56.44 per share. The final purchase price will be adjusted to reflect the ultimate cost to acquire the shares over a period of up to seven months. The 2006 basic and diluted earnings per share calculations reflect the impact associated with the August 2006 accelerated share repurchase program. FirstEnergy intends to settle, in shares or cash, any obligation on its part to pay the difference between the average of the daily volume-weighted average price of the shares as calculated under the program and the initial price of the shares. The effect of any potential settlement in shares is currently unknown.

Reconciliation of Basic and Diluted Earnings per Share of Common Stock	2006	2005	2004
	(In millions, except per share amounts)		
Income from continuing operations	$1,258	$ 879	$ 907
Less: Redemption premium on subsidiary preferred stock	(9)	–	–
Income from continuing operations available to common shareholders	1,249	879	907
Discontinued operations	(4)	12	(29)
Income before cumulative effect of a change in accounting principle	1,245	891	878
Cumulative effect of a change in accounting principle	–	(30)	–
Net income available for common shareholders	$1,245	$ 861	$ 878
Average shares of common stock outstanding – Basic	324	328	327
Assumed exercise of dilutive stock options and awards	3	2	2
Average shares of common stock outstanding – Dilutive	327	330	329
Earnings per share:			
Basic earnings per share:			
Earnings from continuing operations	$ 3.85	$2.68	$2.77
Discontinued operations	(0.01)	0.03	(0.09)
Cumulative effect of change in accounting principle	–	(0.09)	–
Net earnings per basic share	$ 3.84	$2.62	$2.68
Diluted earnings per share:			
Earnings from continuing operations	$ 3.82	$2.67	$2.76
Discontinued operations	(0.01)	0.03	(0.09)
Cumulative effect of change in accounting principle	–	(0.09)	–
Net earnings per diluted share	$ 3.81	$2.61	$2.67

(F) PROPERTY, PLANT AND EQUIPMENT-

Property, plant and equipment reflects original cost (except for nuclear generating assets which were adjusted to fair value in accordance with SFAS 144), 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.

FirstEnergy provides 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 FirstEnergy's subsidiaries' electric plant in 2006, 2005 and 2004 are shown in the following table:

Annual Composite Depreciation Rate	2006	2005	2004
OE	2.8*	2.1*	2.3*
CEI	3.2	2.9	2.8
TE	3.8	3.1	2.8
Penn	2.6	2.4	2.2
JCP&L	2.1	2.2	2.1
Met-Ed	2.3	2.4	2.4
Penelec	2.3	2.6	2.5
FGCO	4.1	N/A	N/A
NGC	2.7	N/A	N/A

Jointly-Owned Generating Stations

JCP&L holds a 50% ownership interest in Yards Creek Pumped Storage Facility – its net book value was approximately $20 million as of December 31, 2006. All other generating units are owned and/or leased by FGCO, NGC and the Companies.

Asset Retirement Obligations

FirstEnergy recognizes a liability for retirement obligations associated with tangible assets in accordance with SFAS 143 and FIN 47. These standards require 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 12, "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. Nuclear fuel is amortized based on the units of production method.

(G) STOCK-BASED COMPENSATION-

FirstEnergy applied the recognition and measurement principles of SFAS 123(R) and related interpretations as of January 1, 2006, which required the expensing of stock-based compensation. All share-based compensation costs are measured at the grant date based on the fair value of the award, and is recognized as an expense over the employee's service period. Those awards that have been classified as liabilities are re-measured each reporting period at the current fair value. FirstEnergy adopted SFAS 123(R) using the modified prospective method under which compensation expense recognized in the year ended December 31, 2006 includes the expense for all share-based payments granted prior to, but not yet vested, as of January 1, 2006.

(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 2006 annual review was completed in the third quarter of 2006 with no impairment indicated. As discussed in Note 10 to the consolidated financial statements, the PPUC issued its order on January 11, 2007 related to the comprehensive rate filing made by Met-Ed and Penelec on April 10, 2006. Prior to issuing the order, the PPUC conducted an informal, nonbinding polling of Commissioners at its public meeting on December 21, 2006 that indicated that the rate increase ultimately granted could be substantially lower than the amounts requested. As a result of the polling, FirstEnergy determined that an interim review of goodwill for its Regulated Services reporting unit would be required. No impairment was indicated as a result of that review.

FirstEnergy's 2005 annual review was completed in the third quarter of 2005 with no impairment indicated. In December 2005, MYR qualified as an asset 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 a result, in the fourth quarter of 2005, the goodwill of MYR was retested for impairment. Based on market valuations that were not available prior to the fourth quarter of 2005, it was determined that the carrying value of MYR exceeded the fair value, resulting in a non-cash goodwill impairment charge of $9 million in the fourth quarter of 2005, with no corresponding income tax benefit.

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 an asset 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. Of that amount, $10 million was reported as an operating expense and $26 million was included in the results from discontinued operations. 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, 2006, FirstEnergy adjusted goodwill related to the divestiture of a non-core asset (MYR), a successful tax claim relating to the former Centerior companies, and adjustments to the former GPU companies due to the realization of tax benefits that had been reserved in purchase accounting. The impairment analysis includes a significant source of cash representing the Companies' recovery of transition costs as described in Note 10. 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 three years ended December 31, 2006 is shown below by segment (see Note 16 - Segment Information):

	Regulated Services	Power Supply Management Services	Facilities Services	Other	Consolidated
			(In millions)		
Balance as of January 1, 2004	$5,993	$ 24	$36	$75	$6,128
Impairment charges			(36)		(36)
Adjustments related to GPU acquisition	(42)				(42)
Balance as of December 31, 2004	5,951	24	–	75	6,050
Impairment charges				(9)	(9)
Non-core asset sales				(12)	(12)
Adjustments related to GPU acquisition	(10)				(10)
Adjustments related to Centerior acquisition	(9)				(9)
Balance as of December 31, 2005	5,932	24	–	54	6,010
Non-core asset sale				(53)	(53)
Adjustments related to Centerior acquisition	(1)				(1)
Adjustments related to GPU acquisition	(58)				(58)
Balance as of December 31, 2006	$5,873	$ 24	$ –	$ 1	$5,898

Investments

At the end of each reporting period, FirstEnergy evaluates its investments for impairment. In accordance with SFAS 115 and FSP SFAS 115-1 and SFAS 124-1, investments classified as available-for-sale securities are evaluated to determine whether a decline in fair value below the cost basis is other-than-temporary. FirstEnergy first considers its intent and ability to hold the investment until recovery and then considers, among other factors, the duration 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. If the decline in fair value is determined to be other-than-temporary, the cost basis of the investment is written down to fair value. Upon adoption of FSPS FAS 115-1 and SFAS 124-1, FirstEnergy began recognizing in earnings the unrealized losses on available-for-sale securities held in the nuclear decommissioning trusts since the trust arrangements, as they are currently defined, do not meet the required ability and intent to hold criteria in consideration of other-than-temporary impairment. The fair value and unrealized gains and losses of the Company's investments are disclosed in Note 5(B) and 5(C).

(I) COMPREHENSIVE INCOME-

Comprehensive income includes net income as reported on the Consolidated Statements of Income and all other changes in common stockholders' equity, excluding the effect from the adoption of SFAS 158. As of December 31, 2006, AOCL consisted of a net liability for unfunded retirement benefits including the implementation of SFAS 158, net of income tax benefits (see Note 3) of $344 million, unrealized gains on investments in securities available for sale of $143 million and unrealized losses on derivative instrument hedges of $58 million. A summary of the changes in FirstEnergy's AOCL balance for the three years ended December 31, 2006 is shown below:

	2006	2005	2004
		(In millions)	
AOCL balance as of January 1,	$ (20)	$(313)	$(353)
Minimum liability for unfunded retirement benefits	–	503	(11)
Unrealized gain (loss) on available for sale securities	109	(31)	46
Unrealized gain on derivative hedges	29	23	29
Other comprehensive income	138	495	64
Income taxes related to OCI	50	202	24
Other comprehensive income, net of tax	88	293	40
Net liability for unfunded retirement benefits due to the implementation of SFAS 158, net of $292 million of income tax benefits	(327)	–	–
AOCL balance as of December 31,	$(259)	$ (20)	$(313)

Other comprehensive loss reclassified to net income in 2006 totaled $4 million (net of income tax benefits of $1 million). Other comprehensive income reclassified to net income in 2005 and 2004 totaled $28 million and $8 million, respectively. These amounts were net of income taxes in 2005 and 2004 of $19 million and $6 million, respectively.

(J) ASSETS HELD FOR SALE AND DISCONTINUED OPERATIONS-

In 2006, FirstEnergy sold its remaining FSG subsidiaries (Roth Bros., Hattenbach, Dunbar, Edwards and RPC) for an aggregate net after-tax gain of $2.2 million. Hattenbach, Dunbar, Edwards, and RPC were accounted for as discontinued operations as of December 31, 2006; Roth Bros. did not meet the criteria for that classification as of December 31, 2006.

In December 2005, MYR had qualified as an asset held for sale but did not meet the criteria to be classified as a discontinued operation. As required by SFAS 142, the goodwill of MYR was tested for impairment, resulting in a non-cash charge of $9 million in the fourth quarter of 2005 (see Note 2(H)). The carrying amounts of MYR's assets and liabilities as of December 31, 2005 held for sale were not material and had not been classified as assets held for sale on FirstEnergy's Consolidated Balance Sheet.

In March 2006, FirstEnergy sold 60% of its interest in MYR for an after-tax gain of $0.2 million. In June 2006, as part of the March agreement, FirstEnergy sold an additional 1.67% interest. As a result of the March sale, FirstEnergy deconsolidated MYR in the first quarter of 2006 and accounted for its remaining 38.33% interest under the equity method. In the fourth quarter of 2006, FirstEnergy sold its remaining MYR interest for an after-tax gain of $8.6 million. The income for the period that MYR was accounted for as an equity method investment has not been included in discontinued operations; however, results for all reporting periods prior to the initial sale in March 2006, including the gain on the sale, were reported as discontinued operations. As of December 31, 2006, no assets have been classified as held for sale.

In 2005, three FSG subsidiaries, Elliott-Lewis, Spectrum and Cranston, and MYR's Power Piping Company subsidiary were sold resulting in an after-tax gain of $13 million. As of December 31, 2005, the remaining FSG subsidiaries had qualified as assets held for sale in accordance with SFAS 144 but did not meet the criteria for discontinued operations. The carrying amounts of FSG's assets and liabilities held for sale as of December 31, 2005 were not material and were not classified as assets held for sale on FirstEnergy's Consolidated Balance Sheet.

In December 2004, the FES retail natural gas business qualified as assets held for sale in accordance with SFAS 144. As required by SFAS 142, goodwill associated with the FES natural gas business was tested for impairment as of December 31, 2004 with no impairment indicated. On March 31, 2005, FES completed the sale for an after-tax gain of $5 million.

Revenues associated with discontinued operations were $225 million, $845 million and $1.15 billion in 2006, 2005 and 2004, 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, 2006:

	2006	2005	2004
		(In millions)	
FES natural gas business	$ –	$ 5	$ 4
FSG subsidiaries	(7)	8	(29)
MYR	3	(1)	(4)
Income (loss) from discontinued operations	$(4)	$12	$(29)

(K) CUMULATIVE EFFECT OF A CHANGE IN ACCOUNTING PRINCIPLE-

Results in 2005 included an after-tax charge of $30 million recorded upon the adoption of FIN 47 in December 2005. FirstEnergy identified applicable legal obligations as defined under FIN 47 at its active and retired generating units, substation control rooms, service center buildings, line shops and office buildings, identifying asbestos as the primary conditional ARO. The Company recorded a conditional ARO liability of $57 million (including accumulated accretion for the period from the date the liability was incurred to the date of adoption), an asset retirement cost of $16 million (recorded as part of the carrying amount of the related long-lived asset), and accumulated depreciation of $12 million. FirstEnergy charged regulatory liabilities for $5 million upon adoption of FIN 47 for the transition amounts related to establishing the ARO for asbestos removal from substation control rooms and service center buildings for OE, Penn, CEI, TE and JCP&L. The remaining cumulative effect adjustment for unrecognized depreciation and accretion of $48 million was charged to income ($30 million, net of tax), or $0.09 per share of common stock (basic and diluted) for the year ended December 31, 2005 (see Note 12).

(L) TAXES-

Details of the total taxes for the three years ended December 31, 2006 are shown in the following tables:

GENERAL TAXES	2006	2005	2004
		(In millions)	
Kilowatt-hour excise*	$241	$244	$236
State gross receipts*	159	151	140
Real and personal property	222	222	208
Social security and unemployment	83	79	76
Other	15	17	18
Total general taxes	$720	$713	$678

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

PROVISION FOR INCOME TAXES	2006	2005	2004
		(In millions)	
Currently payable-			
Federal	$519	$452	$289
State	116	142	135
	635	594	424
Deferred, net-			
Federal	147	72	245
State	28	110	39
	175	182	284
Investment tax credit amortization	(15)	(27)	(27)
Total provision for income taxes	$795	$749	$681
RECONCILIATION OF FEDERAL INCOME TAX EXPENSE AT STATUTORY RATE TO TOTAL PROVISION FOR INCOME TAXES:			
Book income before provision for income taxes	$2,053	$1,628	$1,588
Federal income tax expense at statutory rate	$719	$569	$556
Increases (reductions) in taxes resulting from-			
Amortization of investment tax credits	(15)	(27)	(27)
State income taxes, net of federal income tax benefit	94	165	111
Penalties	–	14	–
Amortization of tax regulatory assets	2	38	33
Preferred stock dividends	5	5	8
Other, net	(10)	(15)	–
Total provision for income taxes	$795	$749	$681
ACCUMULATED DEFERRED INCOME TAXES AS OF DECEMBER 31:			
Property basis differences	$2,595	$2,368	$2,348
Regulatory transition charge	457	537	785
Customer receivables for future income taxes	141	131	103
Deferred customer shopping incentive	219	321	252
Deferred sale and leaseback costs	(86)	(86)	(92)
Nonutility generation costs	(122)	(177)	(174)
Unamortized investment tax credits	(50)	(54)	(61)
Other comprehensive income	(260)	(18)	(219)
Retirement benefits	10	(135)	(280)
Lease market valuation liability	(331)	(361)	(420)
Oyster Creek securitization (Note 10(D))	162	173	184
Loss carryforwards	(426)	(417)	(463)
Loss carryforward valuation reserve	415	402	420
Asset retirement obligations	45	65	71
Nuclear decommissioning	(116)	(105)	(100)
All other	87	82	(30)
Net deferred income tax liability	$2,740	$2,726	$2,324

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 loss carryforwards 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 temporary 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 (See Note 9 for Ohio Tax Legislation discussion).

FirstEnergy has certain tax returns that are under review at the audit or appeals level of the IRS and certain state authorities. Reserves have been recorded, and final settlement of these audits is not expected to have an adverse impact on the financial condition or results of operations of FirstEnergy.

FirstEnergy has capital loss carryforwards of approximately $1 billion, most of which expire in 2007. The deferred tax assets associated with these capital loss carryforwards of ($374 million) are fully offset by a valuation allowance as of December 31, 2006, 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.

During 2006 a ($15) million net change in valuation allowance occurred due to Pennsylvania tax law changes and the utilization of capital loss carryforwards to offset realized capital gains resulting in a $1 million adjustment to goodwill. The valuation allowances also include $48 million for deferred tax assets associated with impairment losses related to certain assets.

FirstEnergy has pre-tax net operating loss carryforwards for state and local income tax purposes of approximately $1.034 billion of which $184 million is expected to be utilized. The associated deferred tax assets are $11 million. These losses expire as follows:

Expiration Period	Amount
	(in millions)
2007-2011	$ 332
2012-2016	37
2017-2021	297
2022-2026	368
	$1,034

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. On January 2, 2007 FirstEnergy made a $300 million voluntary cash contribution to its qualified pension plan. Projections indicated that additional cash contributions will not be required before 2016.

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 co-payments, are also available upon retirement to employees hired prior to January 1, 2005, 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. During 2006, FirstEnergy amended the OPEB plan effective in 2008 to cap the monthly contribution for many of the retirees and their spouses receiving subsidized healthcare coverage. In addition, FirstEnergy has obligations to former or inactive employees after employment, but before retirement for disability related 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 its pension and OPEB plans. The fair value of the plan assets represents the actual market value as of December 31, 2006.

In December 2006, FirstEnergy adopted SFAS 158. This Statement requires employers to recognize an asset or liability for the overfunded or underfunded status of their pension and other postretirement benefit plans. For a pension plan, the asset or liability is the difference between the fair value of the plan's assets and the projected benefit obligation. For any other postretirement benefit plan, the asset or liability is the difference between the fair value of the plan's assets and the accumulated postretirement benefit obligation. The Statement required employers to recognize all unrecognized prior service costs and credits and unrecognized actuarial gains and losses in AOCL, net of tax. Such amounts will be adjusted as they are subsequently recognized as components of net periodic benefit cost or income pursuant to the current recognition and amortization provisions. The incremental impact of adopting SFAS 158 was a decrease of $1.0 billion in pension assets, a decrease of $383 million in pension liabilities and a decrease in AOCL of $327 million, net of tax.

Obligations and Funded Status As of December 31

	Pension Benefits		Other Benefits	
	2006	2005	2006	2005
	(In millions)			
Change in benefit obligation				
Benefit obligation as of January 1	$4,750	$4,364	$1,884	$ 1,930
Service cost	83	77	34	40
Interest cost	266	254	105	111
Plan participants' contributions	–	–	20	18
Plan amendments	3	15	(620)	(312)
Medicare retiree drug subsidy	–	–	6	–
Actuarial (gain) loss	33	310	(119)	197
Benefits paid	(274)	(270)	(109)	(100)
Benefit obligation as of December 31	$4,861	$4,750	$1,201	$ 1,884
Change in fair value of plan assets				
Fair value of plan assets as of January 1	$4,524	$3,969	$ 573	$ 564
Actual return on plan assets	568	325	69	33
Company contribution	–	500	54	58
Plan participants' contribution	–	–	20	18
Benefits paid	(274)	(270)	(109)	(100)
Fair value of plan assets as of December 31	$4,818	$4,524	$ 607	$ 573
Funded status	$(43)	$(226)	$ (594)	$(1,311)
Accumulated benefit obligation	$4,447	$4,327		

	Pension Benefits		Other Benefits	
	2006	2005	2006	2005
	(In millions)			
Amounts Recognized in the Statement of Financial Position				
Noncurrent assets	$ –	$1,023	$ –	$ –
Current liabilities	–	–	–	–
Noncurrent liabilities	(43)	–	(594)	(1,057)
Net asset (liability) as of December 31	$ (43)	$1,023	$ (594)	$(1,057)
Amounts Recognized in Accumulated Other Comprehensive Income				
Prior service cost (credit)	$ 63	$ –	$(1,190)	$ –
Actuarial loss	982	–	702	–
Net amount recognized	$1,045	$ –	$ (488)	$ –
Assumptions Used to Determine Benefit Obligations As of December 31				
Discount rate	6.00%	5.75%	6.00%	5.75%
Rate of compensation increase	3.50%	3.50%		
Allocation of Plan Assets As of December 31				
Asset Category				
Equity securities	64%	63%	72%	71%
Debt securities	29	33	26	27
Real estate	5	2	1	–
Private equities	1	–	–	–
Cash	1	2	1	2
Total	100%	100%	100%	100%

Estimated Items to be Amortized in 2007 Net Periodic Pension Cost from Accumulated Other Comprehensive Income

	Pension Benefits	Other Benefits
	(In millions)	
Prior service cost (credit)	$10	$(149)
Actuarial loss	$41	$ 45

Components of Net Periodic Benefit Costs

	Pension Benefits			Other Benefits		
	2006	2005	2004	2006	2005	2004
	(In millions)					
Service cost	$83	$77	$77	$34	$ 40	$ 36
Interest cost	266	254	252	105	111	112
Expected return on plan assets	(396)	(345)	(286)	(46)	(45)	(44)
Amortization of prior service cost	10	8	9	(76)	(45)	(40)
Recognized net actuarial loss	58	36	39	56	40	39
Net periodic cost	$21	$30	$91	$73	$101	$103

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

	Pension Benefits			Other Benefits		
	2006	2005	2004	2006	2005	2004
Discount rate	5.75%	6.00%	6.25%	5.75%	6.00%	6.25%
Expected long-term return on plan assets	9.00%	9.00%	9.00%	9.00%	9.00%	9.00%
Rate of compensation increase	3.50%	3.50%	3.50%			

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 rates of return on pension plan assets consider 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 on 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 capitalization funds. 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	2006	2005
Health care cost trend rate assumed for next year (pre/post-Medicare)	9-11%	9-11%
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)	2011-2013	2010-2012

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	$ 6	$ (5)
Effect on accumulated postretirement benefit obligation	$33	$(29)

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

	Pension Benefits	Other Benefits
	(In millions)	
2007	$ 247	$ 91
2008	249	91
2009	256	94
2010	269	98
2011	280	101
Years 2012-2016	1,606	537

FirstEnergy also maintains two unfunded benefit plans, an Executive Deferred Compensation Plan (EDCP) and Supplemental Executive Retirement Plan (SERP) under which non-qualified supplemental pension benefits are paid to certain employees in addition to amounts received under the Company's qualified retirement plan, which is subject to IRS limitations on covered compensation. See Note 4(C) for a discussion regarding the stock compensation component of the EDCP. The net periodic pension cost of these plans was $21 million, $16 million and $14 million for the years ended 2006, 2005 and 2004, respectively. The projected benefit obligation and the unfunded status was $170 million and $161 million as of December 31, 2006 and 2005, respectively. The net liability recognized was $301 million and $238 million as of December 31, 2006 and 2005, respectively, and is included in the caption "retirement benefits" on the Consolidated Balance Sheets. The benefit payments, which reflect future service, as appropriate, are expected to be as follows:

	Benefit Payments
	(In millions)
2007	$7
2008	9
2009	8
2010	8
2011	9
Years 2012-2016	61

4. STOCK-BASED COMPENSATION PLANS

FirstEnergy has four stock-based compensation programs: LTIP; EDCP; ESOP; and 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 ranged from one to four years. As of February 2006, all awards under the MYR Plan were exercised. 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. There were no outstanding options at December 31, 2006 under the CE Plan.

Effective January 1, 2006, FirstEnergy adopted SFAS 123(R), which requires the expensing of stock-based compensation. Under SFAS 123(R), all share-based compensation cost is measured at the grant date based on the fair value of the award, and is recognized as an expense over the employee's requisite service period. FirstEnergy adopted the modified prospective method, under which compensation expense recognized in the year ended December 31, 2006 included the expense for all share-based payments granted prior to but not yet vested as of January 1, 2006. Results for prior periods were not restated.

Prior to the adoption of SFAS 123(R) on January 1, 2006, FirstEnergy's LTIP, EDCP, ESOP, and DCPD stock-based compensation programs were accounted for under the recognition and measurement principles of APB 25 and related interpretations. Under APB 25, no compensation expense was reflected in net income for stock options as all options granted under those plans have exercise prices equal to the market value of the underlying common stock on the respective grant dates, resulting in substantially no intrinsic value. The pro forma effects on net income for stock options were instead disclosed in a footnote to the financial statements. Under APB 25 and SFAS 123(R), compensation expense was recorded in the income statement for restricted stock, restricted stock units, performance shares and the EDCP and DCPD programs. No stock options have been granted since the third quarter of 2004. Consequently, the impact of adopting SFAS 123(R) was not material to FirstEnergy's net income and earnings per share in the year ended December 31, 2006.

(A) LTIP-

FirstEnergy's LTIP includes four stock-based compensation programs – restricted stock, restricted stock units, stock options, and performance shares. During 2005, FirstEnergy began issuing restricted stock units and reduced its use of stock options.

Under FirstEnergy's LTIP, total awards cannot exceed 22.5 million shares of common stock or their equivalent. Only stock options, restricted stock and restricted stock units have currently been designated to pay out in common stock, with vesting periods ranging from two months to ten 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, 2006, 3.3 million shares were available for future awards.

Restricted Stock and Restricted Stock Units

Eligible employees receive awards of FirstEnergy common stock or stock units 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:

	2006	2005	2004
Restricted common shares granted	229,271	356,200	62,370
Weighted average market price	$53.18	$41.52	$40.69
Weighted average vesting period (years)	4.47	5.4	2.7
Dividends restricted	Yes	Yes	Yes

Vesting activity for restricted common stock during the year was as follows:

Restricted Stock	Number of Shares	Weighted Average Grant-Date Fair Value
Nonvested at January 1, 2006	424,411	$41.43
Nonvested at December 31, 2006	629,482	45.79
Vested in 2006	19,200	38.80

There are two types of restricted stock unit awards — discretionary-based and performance-based. With the discretionary-based, the Company grants the right to receive, at the end of the period of restriction, a number of shares of common stock of FirstEnergy equal to the number of restricted stock units set forth in each agreement. With performance-based, FirstEnergy grants the right to receive, at the end of the period of restriction, a number of shares of common stock of FirstEnergy equal to the number of restricted stock units set forth in the agreement subject to adjustment based on FirstEnergy's stock performance.

	2006	2005	2004
Restricted common share units granted	440,676	477,920	–
Weighted average vesting period (years)	3.32	3.32	–

Vesting activity for restricted stock units during the year was as follows:

Restricted Stock Units	Number of Shares	Weighted Average Grant-Date Fair Value
Nonvested at January 1, 2006	464,924	$41.44
Nonvested at December 31, 2006	887,794	45.97
Granted during 2006	440,676	50.92
Vested in 2006	6,026	41.42

Compensation expense recognized for restricted stock and restricted stock units during 2006 approximated $17 million. Compensation expense recognized for restricted stock during 2005 and 2004 totaled $10 million and $2 million, respectively.

Stock Options

Stock options were granted 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, 2004	$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 granted	–	–
Options exercised	4,140,893	29.79
Options forfeited	225,606	34.37
Balance, December 31, 2005	8,866,256	33.57
(4,090,829 options exercisable)		31.97
Options granted	–	–
Options exercised	2,221,417	32.65
Options forfeited	26,550	33.36
Balance, December 31, 2006	6,618,289	33.88
(4,160,859 options exercisable)		32.85

Options outstanding by plan and range of exercise price as of December 31, 2006 were as follows:

		Options Outstanding			Options Exercisable	
FE Program	Range of Exercise Prices	Shares	Weighted Average Exercise Price	Remaining Contractual Life	Shares	Weighted Average Exercise Price
FE plan	$19.31 - $29.87	2,744,608	$29.16	5.49	1,887,458	$28.90
	$30.17 - $39.46	3,848,267	$37.31	6.49	2,247,987	$36.27
GPU plan	$23.75 - $35.92	25,414	$24.29	3.37	25,414	$24.29
Total		6,618,289	$33.88	6.07	4,160,859	$32.85

There were no stock options granted in 2006 or 2005. The weighted average fair value of options granted in 2004 are estimated below using the Black-Scholes option-pricing model and the following assumptions:

	2004
Fair value per option	$6.72
Weighted average valuation assumptions:	
Expected option term (years)	7.6
Expected volatility	26.25%
Expected dividend yield	3.88%
Risk-free interest rate	1.99%

Prior to the adoption of SFAS 123(R) compensation expense for FirstEnergy stock options was 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 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.

	2005	2004
	(In millions, except per share amounts)	
Net Income, as reported	$ 861	$ 878
Add back compensation expense reported in net income, net of tax (based on APB 25)*	32	21
Deduct compensation expense based upon estimated fair value, net of tax*	(39)	(35)
Pro forma net income	$ 854	$ 864
Earnings Per Share of Common Stock -		
Basic		
As Reported	$2.62	$2.68
Pro Forma	$2.60	$2.64
Diluted		
As Reported	$2.61	$2.67
Pro Forma	$2.59	$2.63

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

As noted above, FirstEnergy reduced its use of stock options beginning in 2005 and increased its use of performance-based, restricted stock units. FirstEnergy has not accelerated out-of-the-money options in anticipation of adopting SFAS 123(R) on January 1, 2006. As a result, all currently unvested stock options will vest by 2008. Compensation expense recognized for stock options during 2006 total $6 million.

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 performance to a composite of peer companies. Compensation expense recognized for performance shares during 2006, 2005 and 2004 totaled approximately $25 million, $7 million and $5 million, 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 determining the amount of borrowing under the ESOP, assumptions were made including the size and growth rate of the Company's workforce, earnings, dividends, and trading price of common stock. In 2005, the ESOP loan was refinanced ($66 million principal amount) and its term was extended by three years.

In 2006, 2005 and 2004, 922,978 shares, 588,004 shares and 864,151 shares, respectively, were allocated to employees with the corresponding expense recognized based on the shares allocated method. The fair value of 521,818 shares unallocated as of December 31, 2006 was approximately $31 million. Total ESOP-related compensation expense was calculated as follows:

	2006	2005	2004
		(In millions)	
Base compensation	$50	$39	$32
Dividends on common stock held by the ESOP and used to service debt	(11)	(10)	(9)
Net expense	$39	$29	$23

(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 or into an unfunded retirement cash account. An additional 20% 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 (see Note 3). Interest is calculated on the cash allocated to the cash account and the total balance will pay out in cash upon retirement. Of the 1.3 million EDCP stock units authorized, 628,539 stock units were available for future awards as of December 31, 2006. Compensation expense recognized on EDCP stock units in 2006 and 2005 were approximately $5 million each year and approximately $2 million in 2004.

(D) DCPD-

Under the DCPD, directors can elect to allocate all or a portion of their cash retainers, meeting fees and chair fees to deferred stock or deferred cash accounts. If the funds are deferred into the stock account, a 20% match is added to the funds allocated. The 20% 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% match over the three-year vesting period. Directors may also elect to defer their equity retainers into the deferred stock account; however, they do not receive a 20% match on that deferral. DCPD expenses recognized in 2006 and 2005 were approximately $3 million each year and $4 million in 2004. The net liability recognized was $5 million as of December 31, 2006 and 2005 and is included in the caption "retirement benefits" on the Consolidated Balance Sheets.

5. FAIR VALUE OF FINANCIAL INSTRUMENTS

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

All borrowings with initial maturities of less than one year are defined as short-term financial instruments under GAAP and are reported on the Consolidated Balance Sheets at cost in the caption "short-term borrowings", 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 shown in the Consolidated Statements of Capitalization as of December 31:

	2006		2005	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	(In millions)			
Long-term debt	$10,321	$10,725	$10,097	$10,576
Subordinated debentures to affiliated trusts	103	105	103	140
	$10,424	$10,830	$10,200	$10,716

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.

(B) INVESTMENTS-

Investments other than cash and cash equivalents include held-to-maturity securities and available-for-sale securities. The Companies and NGC periodically evaluate their investments for other-than-temporary impairment. They first consider their intent and ability to hold the investment until recovery and then consider, among other factors, the duration 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 following table provides the approximate fair value and related carrying amounts of investments excluding the nuclear decommissioning trust fund investments and investments of $265 million and $244 million for 2006 and 2005 excluded by SFAS 107, "Disclosures about Fair Values of Financial Instruments", as of December 31:

	2006		2005	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	(In millions)			
Restricted funds	$ 11	$ 11	$ –	$ –
Notes receivable	70	67	68	67
Debt securities:				
- Government obligations [1]	383	379	374	370
- Corporate debt securities	3	5	3	40
- Lease obligation bonds	811	908	890	997
Total debt securities	1,197	1,292	1,267	1,407
Equity securities	9	9	20	20
	$1,287	$1,379	$1,355	$1,497

[1] *Excludes $5 million of cash in 2006*

The table above includes restricted funds, notes receivable, nuclear fuel disposal trust investments, NUG trust investments, investments in lease obligation bonds, and other miscellaneous investments. The carrying value of the restricted funds is assumed to approximate market value. The fair value of notes receivable represents 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. The maturity dates range from 2007 to 2040. The nuclear fuel disposal and NUG trust investments consist of debt securities classified as available-for-sale with the fair value determined based on quoted market prices. The investments in lease obligation bonds are accounted for as held-to-maturity securities and the fair value is based on present value of the cash inflows based on the yield to maturity similar to the notes receivable. The maturity dates range from 2007 to 2017.

The following table provides the amortized cost basis, unrealized gains and losses, and fair values for the investments in debt and equity securities above excluding the restricted funds and notes receivable:

	2006				2005			
	Cost Basis	Unrealized Gains	Unrealized Losses	Fair Value	Cost Basis	Unrealized Gains	Unrealized Losses	Fair Value
	(In millions)							
Debt securities	$1,197	$100	$5	$1,292	$1,267	$145	$5	$1,407
Equity securities	9	–	–	9	20	–	–	20
	$1,206	$100	$5	$1,301	$1,287	$145	$5	$1,427

Proceeds from the sale of the investments detailed above, realized gains and losses on those sales, and interest and dividend income for the three years ended December 31, 2006 were as follows:

	2006	2005	2004
	(In millions)		
Proceeds from sales	$1,442	$4,732	$17,564
Realized gains	–	–	4
Realized losses	4	2	1
Interest and dividend income	15	14	11

(C) NUCLEAR DECOMMISSIONING TRUST FUND INVESTMENTS-

Nuclear decommissioning trust investments are classified as available-for-sale with the fair value representing quoted market prices. The Companies and NGC have no securities held for trading purposes. Upon adoption of FSP SFAS 115-1 and SFAS 124-1, FirstEnergy began expensing unrealized losses on available-for-sale securities held in the nuclear decommissioning trusts since the trust arrangements, as they are currently defined, do not meet the required ability and intent to hold criteria in consideration of other-than-temporary impairment. Approximately $13 million of unrealized losses on these available-for-sale securities were reclassified from OCI to earnings upon adoption of these pronouncements. The following table provides the carrying value, which equals fair value of the nuclear decommissioning trust funds as of December 31, 2006 and 2005, respectively. The fair value was determined using the specific identification method.

	2006	2005
	(In millions)	
Debt securities:		
- Government obligations	$ 526	$ 561
- Corporate debt securities	153	125
- Mortgage-backed securities	12	–
	691	686
Equity securities	1,284	1,066
	$1,975[1]	$1,752

[1] *Excludes $2 million of receivables and payables*

The following table summarizes the amortized cost basis, unrealized gains and losses and fair values for decommissioning trust investments as of December 31:

	2006				2005			
	Cost Basis	Unrealized Gains	Unrealized Losses	Fair Value	Cost Basis	Unrealized Gains	Unrealized Losses	Fair Value
	(In millions)							
Debt securities	$ 681	$ 10	$ –	$ 691	$ 681	$ 12	$ 7	$ 686
Equity securities	952	332	–	1,284	898	190	22	1,066
	$1,633	$342	$ –	$1,975[1]	$1,579	$202	$29	$1,752

[1] *Excludes $2 million of receivables and payables*

Unrealized gains applicable to OE's, TE's and the majority of NGC's decommissioning trusts are recognized in OCI in accordance with SFAS 115, as fluctuations in fair value will eventually affect earnings. The decommissioning trusts of JCP&L, Met-Ed and Penelec are subject to regulatory accounting in accordance with SFAS 71. Net unrealized gains and losses are recorded as regulatory assets or liabilities since the difference between investments held in trust and the decommissioning liabilities will be recovered from or refunded to customers.

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, 2006 were as follows:

	2006	2005	2004
		(In millions)	
Proceeds from sales	$1,569	$1,419	$1,234
Realized gains	121	133	144
Realized losses	101	58	43
Interest and dividend income	55	49	45

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.

(D) DERIVATIVES-

FirstEnergy is exposed to financial risks resulting from the fluctuation of interest rates and commodity prices, including prices for electricity, natural gas, coal and energy transmission. 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. 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.

FirstEnergy accounts for derivative instruments on its Consolidated Balance Sheet at their fair value unless they meet the normal purchase and normal sales criterion. Derivatives that meet that criterion are accounted for on the accrual basis. The changes in the fair value of derivative instruments that do not meet the normal purchase and sales criterion are recorded in current earnings, in AOCL, or as part of the value of the hedged item, depending on whether or not it is designated as part of a hedge transaction, the nature of the hedge transaction and hedge effectiveness.

FirstEnergy's primary ongoing hedging activities involve cash flow hedges of electricity and natural gas purchases and anticipated interest payments associated with future debt issuances. The effective portion of such hedges is initially recorded in equity as AOCL and is subsequently recorded in net income, as an expense, when the underlying hedged commodities are delivered or interest payments are made. AOCL as of December 31, 2006 includes a net deferred loss of $58 million for derivative hedging activity. The $20 million decrease from the December 31, 2005 balance of $78 million consists of a $20 million decrease due to net hedge losses included in earnings, with current hedging activity having no effect on net income during the year. Approximately $19 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. Gains and losses from any ineffective portion of the cash flow hedge are recorded directly to earnings. The impact of ineffectiveness on earnings during 2006 and 2005 was not material.

FirstEnergy entered into interest rate derivative transactions in 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, as a component of interest expense, over the periods that hedged interest payments are made – 5, 10 and 30 years. In 2006, a $23 million loss was amortized to interest expense.

FirstEnergy has entered into 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-month LIBOR indices). 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. During 2006, FirstEnergy unwound swaps with a total notional amount of $350 million for which it incurred $1 million in cash losses during 2006. The losses will be recognized over the remaining maturity of each respective hedged security as increased interest expense. As of December 31, 2006, the aggregate notional value of interest rate swap agreements outstanding was $750 million.

During 2005, FirstEnergy entered into several forward starting swap agreements (forward swaps) in order to hedge a portion of the consolidated interest rate risk associated with the future planned issuances of fixed-rate, long-term debt securities for one or more of its consolidated entities in 2006 - 2008. These derivatives are treated as cash flow hedges, protecting against the risk of changes in future interest payments resulting from changes in benchmark U.S. Treasury rates between the date of hedge inception and the date of the debt issuance. As of December 31, 2006, FirstEnergy had entered into forward swaps with an aggregate notional amount of $300 million. As of December 31, 2006, the forward swaps had a fair value of ($4) million.

6. LEASES

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

In 1987, 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. In that same year, 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 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, 2006 are summarized as follows:

	2006	2005	2004
		(In millions)	
Operating leases			
Interest element	$160	$171	$175
Other	190	162	140
Capital leases			
Interest element	1	1	1
Other	2	2	3
Total rentals	$353	$336	$319

Established by OE in 1996, PNBV purchased 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. Similarly, CEI and TE established Shippingport in 1997 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 arrangements effectively reduce lease costs related to those transactions (see Note 7).

The future minimum lease payments as of December 31, 2006 are:

	Capital Leases	Operating Leases: Lease Payments	Operating Leases: Capital Trusts	Operating Leases: Net
		(In millions)		
2007	$1	$ 335	$ 131	$ 204
2008	1	332	105	227
2009	1	334	112	222
2010	1	334	121	213
2011	1	324	121	203
Years thereafter	2	1,748	519	1,229
Total minimum lease payments	7	$3,407	$1,109	$2,298
Executory costs	–			
Net minimum lease payments	7			
Interest portion	2			
Present value of net minimum lease payments	5			
Less current portion	1			
Noncurrent portion	$4			

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, 2006, the above-market lease liabilities for Beaver Valley Unit 2 and the Bruce Mansfield Plant totaled $852 million, of which $85 million is classified as current liabilities.

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 entity's 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. FirstEnergy and its subsidiaries consolidate a VIE when FirstEnergy is determined to be the VIE's primary beneficiary as defined by FIN 46R.

Leases

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

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 3% equity interest by an unaffiliated third party and a 3% 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.

OE, CEI and TE are exposed to losses under the applicable sale and 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 $835 million, $955 million, and $955 million, respectively, 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 $631 million, $97 million and $503 million, respectively, that would not be payable if the casualty value payments are made.

Power Purchase Agreements

In accordance with FIN 46R, FirstEnergy 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 eight 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 eight 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 periodically requests from these eight entities the information necessary 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.

Since FirstEnergy has no equity or debt interests in the NUG entities, its maximum exposure to loss relates primarily to the above-market costs it incurs for power. FirstEnergy expects any above-market costs it incurs to be recovered from customers. As of December 31, 2006, the net above-market loss liability recognized for these eight NUG agreements was $171 million. Purchased power costs from these entities during 2006, 2005 and 2004 were $171 million, $180 million and $175 million, respectively.

8. DIVESTITURES

In 2006, FirstEnergy sold its remaining FSG subsidiaries (Roth Bros., Hattenbach, Dunbar, Edwards and RPC) for an aggregate net after-tax gain of $2.2 million. Based on SFAS 144 criteria, Hattenbach, Dunbar, Edwards, and RPC are accounted for as discontinued operations as of December 31, 2006. Roth Bros. did not meet the criteria for classification as discontinued operations as of December 31, 2006 (see Note 2(J)).

In March 2006, FirstEnergy sold 60% of its interest in MYR for an after-tax gain of $0.2 million. In June 2006, an additional 1.67% interest was sold pursuant to the same March 2006 sale agreement. As a result of the March sale, FirstEnergy deconsolidated MYR in the first quarter of 2006 and accounted for its remaining interest under the equity method. In November 2006, FirstEnergy sold the remaining 38.33% interest in MYR for an after-tax gain of $8.6 million. In accordance with SFAS 144, the income for the time period that MYR was accounted for as an equity method investment has not been included in discontinued operations; however, in accordance with EITF 03-13, *Applying the Conditions in Paragraph 42 of FASB Statement No. 144 in Determining Whether to Report Discontinued Operations*, results for all reporting periods prior to the initial sale in March 2006, including the portion of 2006 prior to the sale are reported as discontinued operations (see Note 2(J)).

In 2005, FirstEnergy sold three FSG subsidiaries – Elliott-Lewis, Spectrum Control Systems and L. H. Cranston and Sons – and an MYR subsidiary – Power Piping Company, resulting in an aggregate after-tax gain of $13 million. All of these sales, with the exception of Spectrum Control Systems met the discontinued operations criteria (see Note 2(J)).

In March 2005, FES completed the sale of its retail natural gas business for an after-tax gain of $5 million. Also in March 2005, FirstEnergy sold 51% of its interest in FirstCom, resulting in an after-tax gain of $4 million. FirstEnergy accounts for its remaining 31.85% interest in FirstCom on the equity basis.

FirstEnergy sold its 50% interest in GLEP in June 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, including the benefits of prior tax capital losses that had been previously fully reserved, which offset the capital gain from the sale.

FirstEnergy completed the sale of its international operations in January 2004 with the sales of its remaining 20.1% interest in Avon (parent of Midlands Electricity in the United Kingdom) and its 28.67% interest in TEBSA, for $12 million. No gain or loss was recognized upon the sales in 2004. Avon and TEBSA were originally acquired as part of FirstEnergy's November 2001 merger with GPU.

9. OHIO TAX LEGISLATION

On June 30, 2005, tax legislation was enacted in the State of Ohio that created a new CAT tax, which is based on qualifying "taxable gross receipts" and does not consider any expenses or costs incurred to generate such receipts, except for items such as cash discounts, returns and allowances, and bad debts. The CAT tax was effective July 1, 2005, and replaces the Ohio income-based franchise tax and the Ohio personal property tax. The CAT tax is phased-in while the current income-based franchise tax is phased-out over a five-year period at a rate of 20% annually, beginning with the year ended 2005, and the personal property tax is phased-out over a four-year period at a rate of approximately 25% annually, beginning with the year ended 2005. During the phase-out period the Ohio income-based franchise tax was or will be computed consistent with the prior tax law, except that the tax liability as computed was multiplied by 80% in 2005; 60% in 2006; 40% in 2007 and 20% in 2008, therefore eliminating the current income-based franchise tax over a five-year period. As a result of the new tax structure, all net deferred tax benefits that were not expected to reverse during the five-year phase-in period were written-off as of June 30, 2005.

The increase to income taxes associated with the adjustment to net deferred taxes in 2005 is summarized below (in millions):

OE	$32
CEI	4
TE	18
Other FirstEnergy subsidiaries	(2)
Total FirstEnergy	$52

Income tax expenses were reduced (increased) during 2005 by the initial phase-out of the Ohio income-based franchise tax and phase-in of the CAT tax as summarized below (in millions):

OE	$3
CEI	5
TE	1
Other FirstEnergy subsidiaries	(3)
Total FirstEnergy	$6

10. REGULATORY MATTERS

(A) 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. 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. On July 14, 2004, NERC independently verified that FirstEnergy had implemented the various initiatives to be completed by June 30 or summer 2004, with minor exceptions noted by FirstEnergy, which exceptions 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 equipment or material upgrades to existing equipment. The FERC or other applicable government agencies and reliability entities may, however, take a different view as to recommended enhancements or may recommend additional enhancements in the future, which could require additional, material expenditures.

As a result of outages experienced in JCP&L's service area in 2002 and 2003, the NJBPU had implemented reviews into JCP&L's service reliability. In 2004, the NJBPU adopted an MOU that set out specific tasks related to service reliability to be performed by JCP&L and a timetable for completion 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 an SRM who made recommendations on appropriate courses of action necessary to ensure system-wide reliability. The Stipulation also incorporates the Executive Summary and Recommendation portions of the final report of a focused audit of JCP&L's Planning and Operations and Maintenance programs and practices (Focused Audit). On February 11, 2005, JCP&L met with the DRA to discuss reliability improvements. The SRM completed his work and issued his final report to the NJBPU on June 1, 2006. JCP&L filed a comprehensive response to the NJBPU on July 14, 2006. JCP&L continues to file compliance reports reflecting activities associated with the MOU and Stipulation.

The EPACT provides for the creation of an ERO to establish and enforce reliability standards for the bulk power system, subject to FERC's review. On February 3, 2006, the FERC adopted a rule establishing certification requirements for the ERO, as well as regional entities envisioned to assume compliance monitoring and enforcement responsibility for the new reliability standards. The FERC issued an order on rehearing on March 30, 2006, providing certain clarifications and essentially affirming the rule.

The NERC has been preparing the implementation aspects of reorganizing its structure to meet the FERC's certification requirements for the ERO. The NERC made a filing with the FERC on April 4, 2006 to obtain certification as the ERO and to obtain FERC approval of pro forma delegation agreements with regional reliability organizations (regional entities). The new FERC rule referred to above, further provides for reorganizing regional entities that would replace the current regional councils and for rearranging their relationship with the ERO. The "regional entity" may be delegated authority by the ERO, subject to FERC approval, for compliance and enforcement of reliability standards adopted by the ERO and approved by the FERC. The ERO filing was noticed on April 7, 2006 and comments and reply comments were filed in May, June and July 2006. On July 20, 2006, the FERC certified the NERC as the ERO to implement the provisions of Section 215 of the Federal Power Act and directed the NERC to make compliance filings addressing governance and non-governance issues and the regional delegation agreements. On September 18, 2006 and October 18, 2006, NERC submitted compliance filings addressing the governance and non-governance issues identified in the FERC ERO Certification Order, dated July 20, 2006. On October 30, 2006, the FERC issued an order accepting most of NERC's governance filings. On January 18, 2007, the FERC issued an order largely accepting NERC's compliance filings addressing non-governance issues, subject to an additional compliance filing requirement.

On April 4, 2006, NERC also submitted a filing with the FERC seeking approval of mandatory reliability standards, as well as for approval with the relevant Canadian authorities. These reliability standards are based, with some modifications and additions, on the current NERC Version 0 reliability standards. The reliability standards filing was subsequently evaluated by the FERC on May 11, 2006, leading to the FERC staff's release of a preliminary assessment that cited many deficiencies in the proposed reliability standards. The NERC and industry participants filed comments in response to the Staff's preliminary assessment. The FERC held a technical conference on the proposed reliability standards on July 6, 2006. The FERC issued a NOPR on the proposed reliability standards on October 20, 2006. In the NOPR, the FERC proposed to approve 83 of the 107 reliability standards and directed NERC to make technical improvements to 62 of the 83 standards approved. The 24 standards that were not approved remain pending at the FERC awaiting further clarification and filings by the NERC and regional entities. The FERC also provided additional clarification within the NOPR regarding the proposed application of final standards and guidance with regard to technical improvements of the standards. On November 15, 2006, NERC submitted several revised reliability standards and three new proposed reliability standards. Interested parties were provided the opportunity to comment on the NOPR (including the revised standards submitted by NERC in November) by January 3, 2007. Numerous parties, including FirstEnergy, filed comments on the NOPR on January 3, 2007. Mandatory reliability standards enforceable with penalties are expected to be in place by the summer of 2007. In a separate order issued October 24, 2006, the FERC approved NERC's 2007 budget and business plan subject to certain compliance filings.

On November 29, 2006, NERC submitted an additional compliance filing with the FERC regarding the Compliance Monitoring and Enforcement Program (CMEP) along with the proposed Delegation Agreements between the ERO and the regional reliability entities. The FERC provided opportunity for interested parties to comment on the CMEP by January 10, 2007. FirstEnergy, as well as other parties, moved to intervene and submitted responsive comments on January 10, 2007. This filing is pending before the FERC.

The ECAR, Mid-Atlantic Area Council, and Mid-American Interconnected Network reliability councils completed the consolidation of these regions into a single new regional reliability organization known as Reliability*First* Corporation. Reliability*First* began operations as a regional reliability council under NERC on January 1, 2006 and on November 29, 2006 filed a proposed Delegation Agreement with NERC to obtain certification consistent with the final rule as a "regional entity" under the ERO. All of FirstEnergy's facilities are located within the Reliability*First* region.

On May 2, 2006, the NERC Board of Trustees adopted eight new cyber security standards that replaced interim standards put in place in the wake of the September 11, 2001 terrorist attacks, and thirteen additional reliability standards. The security standards became effective on June 1, 2006, and the remaining standards will become effective throughout 2006 and 2007. NERC filed these proposed standards with the FERC and relevant Canadian authorities for approval. The cyber security standards were not included in the October 20, 2006 NOPR and are being addressed in a separate FERC docket. On December 11, 2006, the FERC Staff provided its preliminary assessment of these proposed mandatory reliability standards and again cited various deficiencies in the proposed standards, providing interested parties with the opportunity to comment on the assessment by February 12, 2007.

FirstEnergy believes it is in compliance with all current NERC reliability standards. However, based upon a review of the October 20, 2006 NOPR, it appears that the FERC will adopt more strict reliability standards than those contained in the current NERC standards. The financial impact of complying with the new standards cannot be determined at this time. However, the EPACT required that all prudent costs incurred to comply with the new reliability standards be recovered in rates. If FirstEnergy is unable to meet the reliability standards for its bulk power system in the future, it could have a material adverse effect on FirstEnergy's and its subsidiaries' financial condition, results of operations and cash flows.

(B) OHIO-

On October 21, 2003, the Ohio Companies filed their RSP case with the PUCO. On August 5, 2004, the Ohio Companies accepted the RSP as modified and approved by the PUCO in an August 4, 2004 Entry on Rehearing, subject to a CBP. The RSP was intended to establish generation service rates beginning January 1, 2006, in response to the PUCO's concerns about price and supply uncertainty following the end of the Ohio Companies' transition plan market development period. On May 3, 2006, the Supreme Court of Ohio issued an opinion affirming the PUCO's order in all respects, except it remanded back to the PUCO the matter of ensuring the availability of sufficient means for customer participation in the marketplace. The RSP contained a provision that permitted the Ohio Companies to withdraw and terminate the RSP in the event that the PUCO, or the Supreme Court of Ohio, rejected all or part of the RSP. In such event, the Ohio Companies have 30 days from the final order or decision to provide notice of termination. On July 20, 2006 the Ohio Companies filed with the PUCO a Request to Initiate a Proceeding on Remand. In their Request, the Ohio Companies provided notice of termination to those provisions of the RSP subject to termination, subject to being withdrawn, and also set forth a framework for addressing the Supreme Court of Ohio's findings on customer participation. If the PUCO approves a resolution to the issues raised by the Supreme Court of Ohio that is acceptable to the Ohio Companies, the Ohio Companies' termination will be withdrawn and considered to be null and void. On July 26, 2006, the PUCO issued an Entry directing the Ohio Companies to file a plan in a new docket to address the Court's concern. The Ohio Companies filed their RSP Remand CBP on September 29, 2006. Initial comments were filed on January 12, 2007 and reply comments were filed on January 29, 2007. In their reply comments the Ohio Companies described the highlights of a new tariff offering they would be willing to make available to customers that would allow customers to purchase renewable energy certificates associated with a renewable generation source, subject to PUCO approval. No further proceedings are scheduled at this time.

The Ohio Companies filed an application and stipulation with the PUCO on September 9, 2005 seeking approval of the RCP, a supplement to the RSP. On November 4, 2005, the Ohio Companies filed a supplemental stipulation with the PUCO, which constituted an additional component of the RCP filed on September 9, 2005. Major provisions of the RCP include:

- Maintaining the existing level of base distribution rates through December 31, 2008 for OE and TE, and April 30, 2009 for CEI;
- Deferring and capitalizing for future recovery (over a 25-year period) with carrying charges certain distribution costs to be incurred during the period January 1, 2006 through December 31, 2008, not to exceed $150 million in each of the three years;
- Adjusting the RTC and extended RTC recovery periods and rate levels so that full recovery of authorized costs will occur as of December 31, 2008 for OE and TE and as of December 31, 2010 for CEI;
- Reducing the deferred shopping incentive balances as of January 1, 2006 by up to $75 million for OE, $45 million for TE, and $85 million for CEI by accelerating the application of each respective company's accumulated cost of removal regulatory liability; and
- Recovering increased fuel costs (compared to a 2002 baseline) of up to $75 million, $77 million, and $79 million, in 2006, 2007, and 2008, respectively, from all OE and TE distribution and transmission customers through a fuel recovery mechanism. OE, TE, and CEI may defer and capitalize (for recovery over a 25-year period) increased fuel costs above the amount collected through the fuel recovery mechanism.

On January 4, 2006, the PUCO approved, with modifications, the Ohio Companies' RCP to supplement the RSP to provide customers with more certain rate levels than otherwise available under the RSP during the plan period. On January 10, 2006, the Ohio Companies filed a Motion for Clarification seeking clarity on a number of issues. On January 25, 2006, the PUCO issued an Entry on Rehearing granting in part, and denying in part, the Ohio Companies' previous requests and clarifying issues referred to above. The PUCO granted the Ohio Companies' requests to:

- Recognize fuel and distribution deferrals commencing January 1, 2006;
- Recognize distribution deferrals on a monthly basis prior to review by the PUCO Staff;
- Clarify that the types of distribution expenditures included in the Supplemental Stipulation may be deferred; and
- Clarify that distribution expenditures do not have to be "accelerated" in order to be deferred.

The PUCO approved the Ohio Companies' methodology for determining distribution deferral amounts, but denied the Motion in that the PUCO Staff must verify the level of distribution expenditures contained in current rates, as opposed to simply accepting the amounts contained in the Ohio Companies' Motion. On February 3, 2006, several other parties filed applications for rehearing, which the PUCO denied on March 1, 2006. Two of these parties subsequently filed notices of appeal with the Supreme Court of Ohio. The Ohio Supreme Court scheduled this case for oral argument on February 27, 2007. On January 31, 2007, the Ohio Companies filed a stipulation which, among other matters and subject to PUCO approval, affirmed that the supplemental stipulation in the RCP would be implemented. This stipulation was approved by the PUCO on February 14, 2007.

On December 30, 2004, the Ohio Companies filed with the PUCO two applications related to the recovery of transmission and ancillary service related costs. The first application sought recovery of these costs beginning January 1, 2006. The Ohio Companies requested that these costs be recovered through a rider that would be effective on January 1, 2006 and adjusted each July 1 thereafter. The parties reached a settlement agreement that was approved by the PUCO on August 31, 2005. The incremental transmission and ancillary service revenues recovered from January 1 through June 30, 2006 were approximately $54 million. That amount included the recovery of a portion of the 2005 deferred MISO expenses as described below. On April 27, 2006, the Ohio Companies filed the annual update rider to determine revenues ($124 million) from July 2006 through June 2007. The filed rider went into effect on July 1, 2006.

The second application sought authority to defer costs associated with transmission and ancillary service related costs incurred during the period October 1, 2003 through December 31, 2005. On May 18, 2005, the PUCO granted the accounting authority for the Ohio Companies to defer incremental transmission and ancillary service-related charges incurred as a participant in MISO, but only for those costs incurred during the period December 30, 2004 through December 31, 2005. Permission to defer costs incurred prior to December 30, 2004 was denied. The PUCO also authorized the Ohio Companies to accrue carrying charges on the deferred balances. On August 31, 2005, the OCC appealed the PUCO's decision. On January 20, 2006, the OCC sought rehearing of the PUCO's approval of the recovery of deferred costs through the rider during the period January 1, 2006 through June 30, 2006. The PUCO denied the OCC's application on February 6, 2006. On March 23, 2006, the OCC appealed the PUCO's order to the Ohio Supreme Court. On March 27, 2006, the OCC filed a motion to consolidate this appeal with the deferral appeals discussed above and to postpone oral arguments in the deferral appeal until after all briefs are filed in this most recent appeal of the rider recovery mechanism. On March 20, 2006, the Ohio Supreme Court, on its own motion, consolidated the OCC's appeal of the Ohio Companies' case with a similar case involving Dayton Power & Light Company. Oral arguments were heard on May 10, 2006. On November 29, 2006, the Ohio Supreme Court issued its opinion upholding the PUCO's determination that the Ohio Companies may defer transmission and ancillary service related costs incurred on and after December 30, 2004. The Ohio Supreme Court also determined that the PUCO erred when it denied the OCC intervention, but further ruled that such error did not prejudice OCC and, therefore, the Ohio Supreme Court did not reverse or remand the PUCO on this ground. The Ohio Supreme Court also determined that the OCC's appeal was not premature. No party filed a motion for reconsideration with the Ohio Supreme Court.

(C) PENNSYLVANIA-

A February 2002 Commonwealth Court of Pennsylvania decision affirmed the June 2001 PPUC decision regarding approval of the FirstEnergy/GPU merger, remanded the issues of quantification and allocation of merger savings to the PPUC and denied Met-Ed and Penelec the rate relief initially approved in the PPUC decision. On May 4, 2006, the PPUC consolidated the merger savings proceeding with the April 10, 2006 comprehensive rate filing proceeding discussed below. On January 11, 2007, the PPUC entered an order in that rate filing proceeding and determined that no merger savings from prior years should be considered in determining customers' rates.

On January 12, 2005, Met-Ed and Penelec filed, before the PPUC, a request for deferral of transmission-related costs beginning January 1, 2005. Met-Ed and Penelec sought to consolidate this proceeding (and modified their request to provide deferral of 2006 transmission-related costs only) with the comprehensive rate filing made on April 10, 2006, described below. On May 4, 2006, the PPUC approved the modified request.

Met-Ed and Penelec have been purchasing a portion of their PLR requirements from FES through a partial requirements wholesale power sales agreement and various amendments. Under these agreements, FES retained 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. The FES agreements have reduced Met-Ed's and Penelec's exposure to high wholesale power prices by providing power at a fixed price for their uncommitted PLR capacity and energy costs during the term of these agreements with FES.

On April 7, 2006, the parties entered into a Tolling Agreement that arose from FES' notice to Met-Ed and Penelec that FES elected to exercise its right to terminate the partial requirements agreement effective midnight December 31, 2006. On November 29, 2006, Met-Ed, Penelec and FES agreed to suspend the April 7 Tolling Agreement pending resolution of the PPUC's proceedings regarding the Met-Ed and Penelec Transition Rate cases filed April 10, 2006, described below. Separately, on September 26, 2006, Met-Ed and Penelec successfully conducted a competitive RFP for a portion of their PLR obligation for the period December 1, 2006 through December 31, 2008. FES was one of the successful bidders in that RFP process and on September 26, 2006 entered into a Supplier Master Agreement to supply a certain portion of Met-Ed's and Penelec's PLR requirements at market prices that substantially exceed the fixed price in the partial requirements agreements.

Based on the outcome of the Transition Rate filing, as described below, Met-Ed, Penelec and FES agreed to restate the partial requirements power sales agreement effective January 1, 2007. The restated agreement incorporates the same fixed price for residual capacity and energy supplied by FES as in the prior arrangements between the parties, and automatically extends for successive one year terms unless any party gives 60 days' notice prior to the end of the year. The restated agreement allows Met-Ed and Penelec to sell the output of NUG generation to the market and requires FES to provide energy at fixed prices to replace any NUG energy thus sold to the extent needed for Met-Ed and Penelec to satisfy their PLR obligations. The parties have also separately terminated the Tolling, Suspension and Supplier Master agreements in connection with the restatement of the partial requirements agreement. Accordingly, the energy that would have been supplied under the Master Supplier Agreement will now be provided under the restated partial requirements agreement.

If Met-Ed and Penelec were to replace the entire FES supply at current market power prices without corresponding regulatory authorization to increase their generation prices to customers, each company would likely incur a significant increase in operating expenses and experience a material deterioration in credit quality metrics. Under such a scenario, each company's credit profile would no longer be expected to support an investment grade rating for its fixed income securities. Based on the PPUC's January 11, 2007 order described below, if FES ultimately determines to terminate, reduce, or significantly modify the agreement prior to the expiration of Met-Ed's and Penelec's generation rate caps in 2010, timely regulatory relief is not likely to be granted by the PPUC.

Met-Ed and Penelec made a comprehensive rate filing with the PPUC on April 10, 2006 to address a number of transmission, distribution and supply issues. If Met-Ed's and Penelec's preferred approach involving accounting deferrals was approved, the filing would have increased annual revenues by $216 million and $157 million, respectively. That filing included, among other things, a request to charge customers for an increasing amount of market priced power procured through a CBP as the amount of supply provided under the then existing FES agreement is phased out in accordance with the April 7, 2006 Tolling Agreement described above. Met-Ed and Penelec also requested approval of the January 12, 2005 petition for the deferral of transmission-related costs discussed above, but only for those costs incurred during 2006. In this rate filing, Met-Ed and Penelec also requested recovery of annual transmission and related costs incurred on or after January 1, 2007, plus the amortized portion of 2006 costs over a ten-year period, along with applicable carrying charges, through an adjustable rider similar to that implemented in Ohio. Changes in the recovery of NUG expenses and the recovery of Met-Ed's non-NUG stranded costs were also included in the filing. Hearings were held in late August 2006 and briefing occurred in September and October. The ALJs issued their Recommended Decision on November 2, 2006.

The PPUC entered its Opinion and Order in the rate filing proceeding on January 11, 2007. The Order approved the recovery of transmission costs, including the 2006 deferral, and determined that no merger savings from prior years should be considered in determining customers' rates. The request for increases in generation supply rates was denied as were the requested changes in NUG expense recovery and Met-Ed's non-NUG stranded costs. The order decreased Met-Ed's and Penelec's distribution rates by $80 million and $19 million, respectively. These decreases were offset by the increases allowed for the recovery of transmission expenses and the 2006 transmission deferral. Met-Ed's and Penelec's request for recovery of Saxton decommissioning costs was granted and in January 2007, they recognized income of $27 million to establish a regulatory asset for the previously expensed decommissioning costs. Overall rates increased by 5.0% for Met-Ed ($59 million) and 4.5% for Penelec ($50 million). Met-Ed and Penelec filed a Petition for Reconsideration on January 26, 2007 on the issues of consolidated tax savings and rate of return on equity. Other parties filed Petitions for Reconsideration on transmission congestion, transmission deferrals and rate design issues. The PPUC on February 8, 2007 entered an order granting Met-Ed's, Penelec's and the other parties' petitions for procedural purposes. Due to that ruling, the period for appeals to the Commonwealth Court is tolled until 30 days after the PPUC enters a subsequent order ruling on the substantive issues raised in the petitions.

As of December 31, 2006, Met-Ed's and Penelec's regulatory deferrals pursuant to the 1998 Restructuring Settlement (including the Phase 2 Proceedings) and the FirstEnergy/GPU Merger Settlement Stipulation were $303 million and $70 million, respectively. Penelec's $70 million deferral is subject to final resolution of an IRS settlement associated with NUG trust fund proceeds. During the PPUC's annual audit of Met-Ed's and Penelec's NUG stranded cost balances in 2006, it noted a modification to the NUG purchased power stranded cost accounting methodology made by Met-Ed and Penelec. On August 18, 2006, a PPUC Order was entered requiring Met-Ed and Penelec to reflect the deferred NUG cost balances as if the stranded cost accounting methodology modification had not been implemented. As a result of the PPUC's Order, Met-Ed recognized a pre-tax charge of approximately $10.3 million in the third quarter of 2006, representing incremental costs deferred under the revised methodology in 2005. Met-Ed and Penelec continue to believe that the stranded cost accounting methodology modification is appropriate and on August 24, 2006 filed a petition with the PPUC pursuant to its Order for authorization to reflect the stranded cost accounting methodology modification effective January 1, 1999. Hearings on this petition are scheduled for late February 2007. It is not known when the PPUC may issue a final decision in this matter.

On February 1, 2007 the Governor of Pennsylvania proposed an Energy Independence Strategy (EIS). The EIS includes four pieces of preliminary draft legislation that, according to the Governor, is designed to reduce energy costs, promote energy independence and stimulate the economy. Elements of the EIS include the installation of smart meters, funding for solar panels on residences and small businesses, conservation programs to meet demand growth, a requirement that electric distribution companies acquire power through a "Least Cost Portfolio", the utilization of micro-grids and a three year phase-in of rate increases. Since the EIS has only recently been proposed, the final form of any legislation is uncertain. Consequently, FirstEnergy is unable to predict what impact, if any, such legislation may have on its operations.

(D) 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 NUGC rates and market sales of NUG energy and capacity. As of December 31, 2006, the accumulated deferred cost balance totaled approximately $369 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 to securitize the July 31, 2003 deferred balance. On June 8, 2006, the NJBPU approved JCP&L's request to issue securitization bonds associated with BGS stranded cost deferrals. On August 10, 2006, JCP&L Transition Funding II, a wholly owned subsidiary of JCP&L, issued $182 million of transition bonds with a weighted average interest rate of 5.5%.

On December 2, 2005, JCP&L filed its request for recovery of $165 million of actual above-market NUG costs incurred from August 1, 2003 through October 31, 2005 and forecasted above-market NUG costs for November and December 2005. On February 23, 2006, JCP&L filed updated data reflecting actual amounts through December 31, 2005 of $154 million of costs incurred since July 31, 2003. On July 18, 2006, JCP&L further requested an additional $14 million of costs that had been eliminated from the securitized amount. A Stipulation of Settlement was signed by all parties, approved by the ALJ and adopted by the NJBPU in its Order dated December 6, 2006. The Order approves an annual $110 million increase in NUGC rates designed to recover deferred costs incurred since August 1, 2003, and a portion of costs incurred prior to August 1, 2003 that were not securitized. The Order requires that JCP&L absorb any net annual operating losses associated with the Forked River Generating Station. In the Settlement, JCP&L also agreed not to seek an increase to the NUGC to become effective before January 2010, unless the deferred balance exceeds $350 million any time after June 30, 2007.

Reacting to the higher closing prices of the 2006 BGS fixed rate auction, the NJBPU, on March 16, 2006, initiated a generic proceeding to evaluate the auction process and potential options for the future. On April 6, 2006, initial comments were submitted. A public meeting was held on April 21, 2006 and a legislative-type hearing was held on April 28, 2006. On June 21, 2006, the NJBPU approved the continued use of a descending block auction for the Fixed Price Residential Class. JCP&L filed its 2007 BGS company specific addendum on July 10, 2006. On October 27, 2006, the NJBPU approved the auction format to procure the 2007 Commercial Industrial Energy Price as well as the specific rules for both the Fixed Price and Commercial Industrial Energy Price auctions. These rules were essentially unchanged from the prior auctions.

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. 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 DRA filed comments on February 28, 2005 requesting that decommissioning funding be suspended. On March 18, 2005, JCP&L filed a response to the Ratepayer Advocate's comments. A schedule for further NJBPU proceedings has not yet been set.

On August 1, 2005, the NJBPU established a proceeding to determine whether additional ratepayer protections are required at the state level in light of the repeal of PUHCA pursuant to the EPACT. The NJBPU approved regulations effective October 2, 2006 that would prevent a holding company that owns a gas or electric public utility from investing more than 25% of the combined assets of its utility and utility-related subsidiaries into businesses unrelated to the utility industry. These regulations are not expected to materially impact FirstEnergy or JCP&L. Also, in the same proceeding, the NJBPU Staff issued an additional draft proposal on March 31, 2006 addressing various issues including access to books and records, ring-fencing, cross subsidization, corporate governance and related matters. With the approval of the NJBPU Staff, the affected utilities jointly submitted an alternative proposal on June 1, 2006. Comments on the alternative proposal were submitted on June 15, 2006. On November 3, 2006, the NJBPU Staff circulated a revised draft proposal to interested stakeholders.

New Jersey statutes require that the state periodically undertake a planning process, known as the Energy Master Plan (EMP), to address energy related issues including energy security, economic growth, and environmental impact. The EMP is to be developed with involvement of the Governor's Office and the Governor's Office of Economic Growth, and is to be prepared by a Master Plan Committee, which is chaired by the NJBPU President and includes representatives of several State departments.

In October 2006 the current EMP process was initiated with the issuance of a proposed set of objectives which, as to electricity, included the following:

- Reduce the total projected electricity demand by 20% by 2020;
- Meet 22.5% of the State's electricity needs with renewable energy resources by that date;
- Reduce air pollution related to energy use;
- Encourage and maintain economic growth and development;
- Achieve a 20% reduction in both Customer Average Interruption Duration Index and System Average Interruption Frequency Index by 2020;
- Unit prices for electricity should remain no more than +5% of the regional average price (region includes New York, New Jersey, Pennsylvania, Delaware, Maryland and the District of Columbia); and
- Eliminate transmission congestion by 2020.

Comments on the objectives and participation in the development of the EMP have been solicited and a number of working groups have been formed to attain input from a broad range of interested stakeholders including utilities, environmental groups, customer groups, and major customers. Public stakeholder meetings were held in the fall of 2006 and in early 2007, and further public meetings are expected in the summer of 2007. A final draft of the EMP is expected to be presented to the Governor in the fall of 2007 with further public hearings anticipated in early 2008. At this time FirstEnergy cannot predict the outcome of this process nor determine its impact.

(E) FERC MATTERS-

On March 28, 2006, ATSI and MISO filed with the FERC a request to modify ATSI's Attachment O formula rate to include revenue requirements associated with recovery of deferred Vegetation Management Enhancement Program (VMEP) costs.

ATSI estimated that it may defer approximately $54 million of such costs over a five-year period. Approximately $42 million has been deferred as of December 31, 2006. The effective date for recovery was June 1, 2006. The FERC conditionally approved the filing on May 22, 2006, and on July 14, 2006, FERC accepted the ATSI compliance filing. A request for rehearing of the FERC's May 22, 2006 Order was denied by FERC on October 25, 2006. The estimated annual revenues to ATSI from the VMEP cost recovery is $12 million for each of the five years beginning June 1, 2006.

On January 24, 2006, ATSI and MISO filed a request with the FERC to correct ATSI's Attachment O formula rate to reverse revenue credits associated with termination of revenue streams from transitional rates stemming from FERC's elimination of RTOR between the Midwest ISO and PJM. Revenues formerly collected under these transitional rates were included in, and served to reduce, ATSI's zonal transmission rate under the Attachment O formula. Absent the requested correction, elimination of these revenue credits would not be fully reflected in ATSI's formula rate until June 1, 2008. On March 16, 2006, the FERC approved the revenue credit correction without suspension, effective April 1, 2006. One party sought rehearing of the FERC's order, which was denied on June 27, 2006. No petition for review of the FERC's decision was filed. The estimated revenue impact of the correction mechanism is approximately $37 million for the period June 1, 2006 through May 31, 2007.

On November 18, 2004, the FERC issued an order eliminating the RTOR for transmission service between the MISO and PJM regions. The FERC also ordered the MISO, PJM and the transmission owners within MISO and PJM to submit compliance filings containing a SECA mechanism to recover lost RTOR revenues during a 16-month transition period from load serving entities. The FERC issued orders in 2005 setting the SECA for hearing. ATSI, JCP&L, Met-Ed, Penelec, and FES participated in the FERC hearings held in May 2006 concerning the calculation and imposition of the SECA charges. The Presiding Judge issued an Initial Decision on August 10, 2006, rejecting the compliance filings made by the RTOs and transmission owners, ruling on various issues and directing new compliance filings. This decision is subject to review and approval by the FERC. Briefs addressing the Initial Decision were filed on September 11, 2006 and October 20, 2006. A final order could be issued by the FERC in early 2007.

On January 31, 2005, certain PJM transmission owners made three filings with the FERC pursuant to a settlement agreement previously approved by the FERC. JCP&L, Met-Ed and Penelec were parties to that proceeding and joined in two of the filings. In the first filing, the settling transmission owners submitted a filing justifying continuation of their existing rate design within the PJM RTO. In the second filing, the settling transmission owners proposed a revised Schedule 12 to the PJM tariff designed to harmonize the rate treatment of new and existing transmission facilities. Interventions and protests were filed on February 22, 2005. In the third filing, Baltimore Gas and Electric Company and Pepco Holdings, Inc. requested a formula rate for transmission service provided within their respective zones. On May 31, 2005, the FERC issued an order on these cases. First, it set for hearing the existing rate design and indicated that it will issue a final order within six months. American Electric Power Company, Inc. filed in opposition proposing to create a "postage stamp" rate for high voltage transmission facilities across PJM. Second, the FERC approved the proposed Schedule 12 rate harmonization. Third, the FERC accepted the proposed formula rate, subject to refund and hearing procedures. On June 30, 2005, the settling PJM transmission owners filed a request for rehearing of the May 31, 2005 order. On March 20, 2006, a settlement was filed with FERC in the formula rate proceeding that generally accepts the companies' formula rate proposal. The FERC issued an order approving this settlement on April 19, 2006. Hearings in the PJM rate design case concluded in April 2006. On July 13, 2006, an Initial Decision was issued by the ALJ. The ALJ adopted the FERC Trial Staff's position that the cost of all PJM transmission facilities should be recovered through a postage stamp rate. The ALJ recommended an April 1, 2006 effective date for this change in rate design. If the FERC accepts this recommendation, the transmission rate applicable to many load zones in PJM would increase. FirstEnergy believes that significant additional transmission revenues would have to be recovered from the JCP&L, Met-Ed and Penelec transmission zones within PJM. JCP&L, Met-Ed and Penelec, as part of the Responsible Pricing Alliance, filed a brief addressing the Initial Decision on August 14, 2006 and September 5, 2006. The case will be reviewed by the FERC with a decision anticipated in early 2007.

On November 1, 2005, FES filed two power sales agreements for approval with the FERC. One power sales agreement provided for FES to provide the PLR requirements of the Ohio Companies at a price equal to the retail generation rates approved by the PUCO for a period of three years beginning January 1, 2006. The Ohio Companies will be relieved of their obligation to obtain PLR power requirements from FES if the Ohio CBP results in a lower price for retail customers. A similar power sales agreement between FES and Penn permits Penn to obtain its PLR power requirements from FES at a fixed price equal to the retail generation price during 2006.

On December 29, 2005, the FERC issued an order setting the two power sales agreements for hearing. The order criticized the Ohio CBP, and required FES to submit additional evidence in support of the reasonableness of the prices charged in the power sales agreements. On July 14, 2006, the Chief Judge granted the joint motion of FES and the Trial Staff to appoint a settlement judge in this proceeding and the procedural schedule was suspended pending settlement discussions among the parties. A settlement conference was held on September 5, 2006. FES and the Ohio Companies, Penn, and the PUCO, along with other parties, reached an agreement to settle the case. The settlement was filed with the FERC on October 17, 2006, and was unopposed by the remaining parties, including the FERC Trial Staff. This settlement was accepted by the FERC on December 8, 2006.

The terms of the settlement provide for modification of both the Ohio and Penn power supply agreements with FES. Under the Ohio power supply agreement, separate rates are established for the Ohio Companies' PLR requirements; special retail contract requirements, wholesale contract requirements, and interruptible buy-through retail load requirements. For their PLR and special retail contract requirements, the Ohio Companies will pay FES no more than the lower of (i) the sum of the retail generation charge, the rate stabilization charge, the fuel recovery mechanism charge, and FES' actual incremental fuel costs for such sales; or (ii) the wholesale price cap. Different wholesale price caps are imposed for PLR sales, special retail contracts, and wholesale contracts. The wholesale price for interruptible buy-through retail load requirements is limited to the actual spot price of power obtained by FES to provide this power. FES billed the Ohio Companies for the additional amount payable to FES for incremental fuel costs on power supplied during 2006. The total power supply cost billed by FES was lower in each case than the wholesale price caps specified in the settlement accepted by the FERC. In addition, pursuant to the settlement, the wholesale rate charged by FES under the Penn power supply agreement can be no greater than the generation component of charges for retail PLR load in Pennsylvania. The modifications to the Ohio and Pennsylvania power supply agreements became effective January 1, 2006. The Penn supply agreement subject to the settlement expired at midnight on December 31, 2006.

As a result of Penn's PLR competitive solicitation process approved by the PPUC for the period January 1, 2007 through May 31, 2008, FES was selected as the winning bidder for a number of the tranches for individual customer classes. The balance of the tranches will be supplied by unaffiliated power suppliers. On October 2, 2006, FES filed an application with the FERC under Section 205 of the Federal Power Act for authorization to make these affiliate sales to Penn. Interventions or protests were due on this filing on October 23, 2006. Penn was the only party to file an intervention in this proceeding. This filing was accepted by the FERC on November 15, 2006, and no requests for rehearing were filed.

On February 15, 2007, MISO filed documents with the FERC to establish a market-based, competitive ancillary services market. MISO contends that the filing will integrate operating reserves into MISO's existing day-ahead and real-time settlements process, incorporate opportunity costs into these markets, address scarcity pricing through the implementation of a demand curve methodology, foster demand response in the provision of operating reserves, and provide for various efficiencies and optimization with regard to generation dispatch. The filing also proposes amendments to existing documents to provide for the transfer of balancing functions from existing local balancing authorities to MISO. MISO will then carry out this reliability function as the NERC-certified balancing authority for the MISO region. MISO is targeting implementation for the second or third quarter of 2008. The FERC has established March 23, 2007, as the date for interested parties to submit comments addressing the filing. The filing has not yet been fully evaluated to assess its impact on FirstEnergy's operations.

On February 16, 2007, the FERC issued a final rule that revises its decade-old open access transmission regulations and policies. The FERC explained that the final rule is intended to strengthen non-discriminatory access to the transmission grid, facilitate FERC enforcement, and provide for a more open and coordinated transmission planning process. The final rule will not be effective until 60 days after publication in the Federal Register. The final rule has not yet been fully evaluated to assess its impact on FirstEnergy's operations.

11. CAPITALIZATION

(A) COMMON STOCK-

Retained Earnings and Dividends

Under applicable federal law, FirstEnergy can pay cash dividends to its common shareholders only from retained or current earnings. As of December 31, 2006, FirstEnergy's unrestricted retained earnings were $2.8 billion. Each of FirstEnergy's electric utility subsidiaries has authorization from the FERC to pay cash dividends to FirstEnergy from paid-in capital accounts, as long as its equity to total capitalization ratio (without consideration of retained earnings) remains above 35%. 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 further restrict the payment of dividends on their common and preferred stock. As of December 31, 2006, none of these provisions materially restricted FirstEnergy's subsidiaries' ability to pay cash dividends to FirstEnergy.

On December 19, 2006, the Board of Directors increased the indicated annual common stock dividend to $2.00 per share, payable quarterly at a rate of $0.50 per share beginning in the first quarter of 2007. Dividends declared in 2006 were $1.85 which included three quarterly dividends of $0.45 per share paid in the second, third and fourth quarters of 2006 and a quarterly dividend of $0.50 per share payable in the first quarter of 2007. Dividends declared in 2005 were $1.705 which included quarterly dividends of $0.4125 per share paid in the second and third quarters of 2005, a quarterly dividend of $0.43 per share paid in the fourth quarter of 2005 and a quarterly dividend of $0.45 per share paid in the first quarter of 2006. 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.

(B) PREFERRED AND PREFERENCE STOCK-

FirstEnergy has 5 million authorized shares of $100 par value preferred stock and OE has 8 million authorized shares of $25 par value preferred stock. CEI's, Met-Ed's and Penelec's preferred stock authorizations consist of 4 million, 10 million and 11.435 million shares, respectively, without par value. No preferred shares were outstanding for those companies as of December 31, 2006 or 2005.

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-

Subordinated Debentures to Affiliated Trusts

As of December 31, 2006, CEI's wholly owned statutory business trust, Cleveland Electric Financing Trust, had $100 million of outstanding 9.00% preferred securities that mature in 2031. The sole assets of the trust are CEI's subordinated debentures having the same rate and maturity date as the preferred securities.

CEI formed the trust to sell preferred securities and invested 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 were redeemable at 100% 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.

Securitized Transition Bonds

The consolidated financial statements of FirstEnergy and JCP&L include the results of JCP&L Transition Funding and JCP&L

Transition Funding II, wholly owned limited liability companies of JCP&L. In June 2002, JCP&L Transition Funding 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. In August 2006, JCP&L Transition Funding II sold $182 million of transition bonds to securitize the recovery of deferred costs associated with JCP&L's supply of BGS.

JCP&L did not purchase and does not own any of the transition bonds, which are included as long-term debt on FirstEnergy's Consolidated Balance Sheet. As of December 31, 2006, $429 million of transition bonds are outstanding. The transition bonds are the sole obligations of JCP&L Transition Funding and JCP&L Transition Funding II and are collateralized by each company's equity and assets, which consists primarily of bondable transition property.

Bondable transition property represents the irrevocable right under New Jersey law of a utility company to charge, collect and receive from its customers, through a non-bypassable TBC, the principal amount and interest on transition bonds and other fees and expenses associated with their issuance. JCP&L sold its bondable transition property to JCP&L Transition Funding and JCP&L Transition Funding II and, as servicer, manages and administers the bondable transition property, including the billing, collection and remittance of the TBC, pursuant to separate servicing agreements with JCP&L Transition Funding and JCP&L Transition Funding II. For the two series of transition bonds, JCP&L is entitled to aggregate annual servicing fees of up to $628,000 that are payable from TBC collections.

Other Long-term Debt

Each of the Companies has a first mortgage indenture under which it issues FMB 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. There also exist cross-default provisions among financing arrangements of FirstEnergy and the Companies.

Based on the amount of FMB authenticated by the respective mortgage bond trustees through December 31, 2006, the Companies' annual sinking fund requirement for all FMB issued under the various mortgage indentures amounts to $104 million. OE and Penn expect to deposit funds with their respective mortgage bond trustees in 2007 that will then be withdrawn upon the surrender for cancellation of a like principal amount of FMB, specifically authenticated for such purposes against unfunded property additions or against previously retired FMB. This method can result in minor increases in the amount of the annual sinking fund requirement. JCP&L, Met-Ed and Penelec could fulfill their sinking fund obligations by providing bondable property additions, previously retired FMB or cash to the respective mortgage bond trustees.

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

	(In millions)
2007	$1,867
2008	418
2009	287
2010	214
2011	1,540

Included in the table above are amounts for certain variable interest rate pollution control revenue bonds that have provisions by which individual debt holders are required to "put back" the respective debt to the issuer for redemption prior to its maturity date. These amounts are $1.6 billion, $82 million and $15 million in 2006, 2008 and 2010, respectively, representing the next time the debt holders may exercise this provision.

Obligations to repay certain pollution control revenue bonds are secured by several series of FMB. Certain pollution control revenue bonds are entitled to the benefit of irrevocable bank LOCs of $1.6 billion as of December 31, 2006 or noncancelable municipal bond insurance policies of $343 million at December 31, 2006 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, FGCO, NGC and the Companies are entitled to a credit against their obligation to repay those bonds. FGCO, NGC and the Companies pay annual fees of 0.55% to 1.70% of the amounts of the LOCs to the issuing banks and 0.16% to 0.38% 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. Certain of the issuing banks and insurers hold FMB as security for such reimbursement obligations.

Certain secured notes of CEI and TE are entitled to the benefit of noncancelable municipal bond insurance policies of $120 million and $30 million, respectively, to pay principal of, or interest on, the applicable notes. To the extent that drawings are made under the policies, CEI and TE are entitled to a credit against their obligation to repay those notes. CEI and TE are obligated to reimburse the insurer for any drawings thereunder.

CEI and TE have unsecured LOCs of approximately $194 million in connection with the sale and leaseback of Beaver Valley Unit 2 for which they are jointly and severally liable. OE has LOCs of $291 million and $134 million in connection with the sale and leaseback of Beaver Valley Unit 2 and Perry Unit 1, respectively. 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.

12. ASSET RETIREMENT OBLIGATIONS-

FirstEnergy has recognized applicable legal obligations under SFAS 143 for nuclear power plant decommissioning, reclamation of a sludge disposal pond and closure of two coal ash disposal sites. In addition, FirstEnergy has recognized conditional retirement obligations (primarily for asbestos remediation) in accordance with FIN 47, which was implemented on December 31, 2005.

The ARO liability of $1.19 billion as of December 31, 2006 primarily relates to the nuclear decommissioning of the Beaver Valley, Davis-Besse, Perry and TMI-2 nuclear generating facilities. The obligation to decommission these units was developed based on site specific studies performed by an independent engineer. FirstEnergy uses an expected cash flow approach to measure the fair value of the nuclear decommissioning ARO.

In 2006, FirstEnergy revised the ARO associated with Perry as a result of revisions to the 2005 decommissioning study. The present value of revisions in the estimated cash flows associated with projected decommissioning costs increased the ARO and corresponding plant asset for Perry by $4 million. The ARO for FirstEnergy's sludge disposal pond located near the Mansfield plant was revised in 2006 due to an updated cost study. The present value of revisions in the estimated cash flows associated with projected remediation costs associated with the site decreased the ARO and corresponding plant asset by $6 million. In May 2006, CEI sold its interest in the Ashtabula C plant. As part of the transaction, CEI settled the $6 million ARO that had been established with the adoption of FIN 47.

In 2005, FirstEnergy revised the ARO associated with Beaver Valley Units 1 and 2, Davis-Besse and Perry, as a result of updated decommissioning studies. The present value of revisions in the estimated cash flows associated with projected decommissioning costs increased the ARO for Beaver Valley Unit 1 by $21 million and decreased the ARO for Beaver Valley Unit 2 by $22 million, resulting in a net decrease in the ARO liability and corresponding plant asset of $1 million. The present value of revisions in the estimated cash flows associated with projected decommissioning costs decreased the ARO and corresponding plant asset for Davis-Besse and Perry by $21 million and $57 million, respectively.

FirstEnergy maintains nuclear decommissioning trust funds that are legally restricted for purposes of settling the nuclear decommissioning ARO. As of December 31, 2006, the fair value of the decommissioning trust assets was approximately $2.0 billion.

FIN 47 provides accounting standards for conditional retirement obligations associated with tangible long-lived assets, requiring recognition of the fair value of a liability for an ARO in the period in which it is incurred if a reasonable estimate can be identified. FIN 47 states that an obligation exists even though there may be uncertainty about timing or method of settlement and further clarifies SFAS 143, stating that the uncertainty surrounding the timing and method of settlement when settlement is conditional on a future event occurring should be reflected in the measurement of the liability, not in the recognition of the liability. Accounting for conditional ARO under FIN 47 is the same as described above for SFAS 143.

FirstEnergy identified applicable legal obligations as defined under the new standard at its active and retired generating units, substation control rooms, service center buildings, line shops and office buildings, identifying asbestos remediation as the primary conditional ARO. As a result of adopting FIN 47 in December 2005, FirstEnergy recorded a conditional ARO liability of $57 million (including accumulated accretion for the period from the date the liability was incurred to the date of adoption), an asset retirement cost of $16 million (recorded as part of the carrying amount of the related long-lived asset) and accumulated depreciation of $12 million. FirstEnergy charged a regulatory liability of $5 million upon adoption of FIN 47 for the transition amounts related to establishing the ARO for asbestos removal from substation control rooms and service center buildings for OE, Penn, CEI, TE and JCP&L. The remaining cumulative effect adjustment for unrecognized depreciation and accretion of $48 million was charged to income ($30 million, net of tax), — $0.09 per share of common stock (basic and diluted) for the year ended December 31, 2005.

The following table describes the changes to the ARO balances during 2006 and 2005.

ARO Reconciliation	2006	2005
	(In millions)	
Balance at beginning of year	$1,126	$1,078
Liabilities incurred	–	–
Liabilities settled	(6)	–
Accretion	72	70
Revisions in estimated cash flows	(2)	(79)
FIN 47 ARO upon adoption	–	57
Balance at end of year	$1,190	$1,126

The following table provides the December 31, 2005 balance of the conditional ARO as if FIN 47 had been adopted on January 1, 2005:

Adjusted ARO Reconciliation	2005
	(In millions)
Beginning balance as of January 1, 2005	$54
Accretion	3
Ending balance as of December 31, 2005	$57

The effect on income as if FIN 47 had been applied during 2004 was immaterial.

13. SHORT-TERM BORROWINGS AND BANK LINES OF CREDIT

FirstEnergy had approximately $1.1 billion of short-term indebtedness as of December 31, 2006, comprised of $1.0 billion in borrowings under a $2.75 billion revolving line of credit and $103 million of other bank borrowings. Total short-term bank lines of committed credit to FirstEnergy and the Companies as of December 31, 2006 were approximately $3.4 billion.

On August 24, 2006, FirstEnergy and certain of its subsidiaries, as borrowers, entered into a new $2.75 billion five-year revolving credit facility, which replaced FirstEnergy's prior $2 billion credit facility. FirstEnergy may request an increase in the total commitments available under the new facility up to a maximum of $3.25 billion. Commitments under the new facility are available until August 24, 2011, unless the lenders agree, at the request of the Borrowers, to two additional one-year extensions. Generally, borrowings under the facility must be repaid within 364 days. Available amounts for each Borrower are subject to a specified sub-limit, as well as applicable regulatory and other limitations. As of December 31, 2006, FirstEnergy was the only borrower on this revolver. The annual facility fee is 0.125%.

The Companies, with the exception of TE and JCP&L, each have a wholly owned subsidiary whose borrowings are secured by customer accounts receivable purchased from its respective parent company. The CEI subsidiary's borrowings are also secured by customer accounts receivable purchased from TE. Each subsidiary company has its own receivables financing arrangement and, as a separate legal entity with separate creditors, would have to satisfy its obligations to creditors before any of its remaining assets could be available to its parent company. The receivables financing borrowing capacity by company are shown in the following table. There were no outstanding borrowings as of December 31, 2006.

Subsidiary Company	Parent Company	Capacity	Annual Facility Fee
		(In millions)	
OES Capital, Incorporated	OE	$ 170	0.15*
Centerior Funding Corp.	CEI	200	0.15
Penn Power Funding LLC	Penn	25	0.13
Met-Ed Funding LLC	Met-Ed	80	0.13
Penelec Funding LLC	Penelec	75	0.13
		$ 550	

The weighted average interest rates on short-term borrowings outstanding as of December 31, 2006 and 2005 were 5.71% and 4.68%, respectively. The annual facility fees on all current committed short-term bank lines of credit range from 0.125% to 0.15%.

14. 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. FirstEnergy's maximum potential assessment under the industry retrospective rating plan would be $402 million per incident but not more than $60 million in any one year for each incident.

FirstEnergy is also insured under policies for each nuclear plant. Under these policies, up to $2.75 billion is provided for property damage and decontamination costs. FirstEnergy has also obtained approximately $2.0 billion of insurance coverage for replacement power costs. Under these policies, FirstEnergy can be assessed a maximum of approximately $72 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.

FirstEnergy intends to maintain insurance against nuclear risks, as described above, 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 FirstEnergy's 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 FirstEnergy's insurance policies, or to the extent such insurance becomes unavailable in the future, FirstEnergy 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. These agreements include contract guarantees, surety bonds and LOCs. As of December 31, 2006, outstanding guarantees and other assurances aggregated approximately $5.4 billion -contract guarantees $2.5 billion, surety bonds $0.1 billion and LOCs $2.8 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 credit support for subsidiary financings or refinancings of costs related to 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 $1.0 billion (included in the $2.5 billion discussed above) as of December 31, 2006 would increase amounts otherwise payable 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. As of December 31, 2006, FirstEnergy's maximum exposure under these collateral provisions was $468 million.

Most of FirstEnergy's surety bonds are backed by various indemnities common within the insurance industry. Surety bonds and related FirstEnergy guarantees of $130 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 ($27 million as of December 31, 2006), which is renewable and declines yearly based upon the senior outstanding debt of TEBSA.

(C) ACCELERATED SHARE REPURCHASE PROGRAM-

On August 9, 2006, FirstEnergy entered into an accelerated share repurchase agreement with a financial institution counterparty under which FirstEnergy repurchased 10.6 million shares, or approximately 3.2%, of its outstanding common stock on August 10, 2006 at an initial price of $56.44 per share, or a total initial purchase price of $600 million. This forward sale contract is being accounted for as an equity instrument. The final purchase price is subject to a contingent purchase price adjustment based on the average of the daily volume-weighted average prices over a subsequent purchase period of up to seven months, as well as other purchase price adjustments in the event of an extraordinary cash dividend or other dilution events. The price adjustment can be settled, at FirstEnergy's option, in cash or in shares of its common stock. The size of any settlement amount and whether it is to be paid or received by FirstEnergy will depend upon the average of the daily volume-weighted average prices of the shares as calculated by the counterparty under the program. The settlement is expected to occur in the first quarter of 2007.

The accelerated share repurchase was completed under a program authorized by the Board of Directors on June 20, 2006 to repurchase up to 12 million shares of common stock. At management's discretion, additional shares may be acquired under the program on the open market or through privately negotiated transactions, subject to market conditions and other factors. The Board's authorization of the repurchase program does not require FirstEnergy to make any further repurchases of shares and the program may be terminated at any time. On January 30, 2007, FirstEnergy's Board of Directors authorized a new share repurchase program for up to 16 million shares, or approximately 5% of FirstEnergy's outstanding common stock. This new program supplements the prior repurchase program approved on June 20, 2006, such that up to 26.6 million potential shares may ultimately be repurchased under the combined plans. At management's discretion, shares may be acquired on the open market or through privately negotiated transactions, subject to market conditions and other factors. FirstEnergy is currently in negotiations with a major financial institution to enter into a new accelerated share repurchase program contingent among other things on amending its current accelerated share repurchase program to allow FirstEnergy to enter into the new accelerated repurchase program.

(D) ENVIRONMENTAL MATTERS-

Various federal, state and local authorities regulate FirstEnergy with regard to air and water quality and other environmental matters. The effects of compliance on FirstEnergy with regard to environmental matters could have a material adverse effect on 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 changes in regulatory policies and what, if any, the effects of such changes would be. FirstEnergy estimates additional capital expenditures for environmental compliance of approximately $1.8 billion for 2007 through 2011.

FirstEnergy accrues environmental liabilities only when it concludes that it is probable that it has an obligation for such costs and can reasonably estimate the amount of such costs. Unasserted claims are reflected in FirstEnergy's determination of environmental liabilities and are accrued in the period that they become both probable and reasonably estimable.

Clean Air Act Compliance

FirstEnergy is required to meet federally-approved SO_2 emissions 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. FirstEnergy believes it is currently in compliance with this policy, but cannot predict what action the EPA may take in the future with respect to the interim enforcement policy.

The EPA Region 5 issued a Finding of Violation and NOV to the Bay Shore Power Plant dated June 15, 2006 alleging violations to various sections of the Clean Air Act. FirstEnergy has disputed those alleged violations based on its Clean Air Act permit, the Ohio SIP and other information provided at an August 2006 meeting with the EPA. The EPA has several enforcement options (administrative compliance order, administrative penalty order, and/or judicial, civil or criminal action) and has indicated that such option may depend on the time needed to achieve and demonstrate compliance with the rules alleged to have been violated.

FirstEnergy complies 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. NO_X 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 NO_X reductions at FirstEnergy's facilities. The EPA's NO_X Transport Rule imposes uniform reductions of NO_X emissions (an approximate 85% reduction in utility plant NO_X 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 NO_X emissions are contributing significantly to ozone levels in the eastern United States. FirstEnergy believes its facilities are also complying with the NO_X budgets established under 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 fine particulate matter. In March 2005, the EPA finalized the CAIR covering a total of 28 states (including Michigan, New Jersey, Ohio and Pennsylvania) and the District of Columbia based on proposed findings that air emissions from 28 eastern states and the District of Columbia significantly contribute to non-attainment of the NAAQS for fine particles and/or the "8-hour" ozone NAAQS in other states. CAIR provided each affected state until 2006 to develop implementing regulations to achieve additional reductions of NO_X and SO_2 emissions in two phases (Phase I in 2009 for NO_X, 2010 for SO_2 and Phase II in 2015 for both NO_X and SO_2). FirstEnergy's Michigan, Ohio and Pennsylvania fossil-fired generation facilities will be subject to caps on SO_2 and NO_X emissions, whereas its New Jersey fossil-fired generation facility will be subject to only a cap on NO_X emissions. According to the EPA, SO_2 emissions will be reduced by 45% (from 2003 levels) by 2010 across the states covered by the rule, with reductions reaching 73% (from 2003 levels) by 2015, capping SO_2 emissions in affected states to just 2.5 million tons annually. NO_X emissions will be reduced by 53% (from 2003 levels) by 2009 across the states covered by the rule, with reductions reaching 61% (from 2003 levels) by 2015, achieving a regional NO_X cap of 1.3 million tons annually. The future cost of compliance with these regulations may be substantial and will depend on how they are ultimately implemented by the states in which FirstEnergy operates 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. In March 2005, the EPA finalized the CAMR, which provides a cap-and-trade program to reduce mercury emissions from coal-fired power plants in two phases. Initially, mercury emissions will be capped nationally at 38 tons by 2010 (as a "co-benefit" from implementation of SO_2 and NO_X emission caps under the EPA's CAIR program). Phase II of the mercury cap-and-trade program will cap nationwide mercury emissions from coal-fired power plants at 15 tons per year by 2018. However, the final rules give states substantial discretion in developing rules to implement these programs. In addition, both the CAIR and the CAMR have been challenged in the United States Court of Appeals for the District of Columbia. FirstEnergy's future cost of compliance with these regulations may be substantial and will depend on how they are ultimately implemented by the states in which FirstEnergy operates affected facilities.

The model rules for both CAIR and CAMR contemplate an input-based methodology to allocate allowances to affected facilities. Under this approach, allowances would be allocated based on the amount of fuel consumed by the affected sources. FirstEnergy would prefer an output-based generation-neutral methodology in which allowances are allocated based on megawatts of power produced, allowing new and non-emitting generating facilities (including renewables and nuclear) to be entitled to their proportionate share of the allowances. Consequently, FirstEnergy will be disadvantaged if these model rules were implemented as proposed because FirstEnergy's substantial reliance on non-emitting (largely nuclear) generation is not recognized under the input-based allocation.

Pennsylvania has submitted a new mercury rule for EPA approval that does not provide a cap and trade approach as in the CAMR, but rather follows a command and control approach imposing emission limits on individual sources. Pennsylvania's mercury regulation would deprive FES of mercury emission allowances that were to be allocated to the Mansfield Plant under the CAMR and that would otherwise be available for achieving FirstEnergy system-wide compliance. The future cost of compliance with these regulations, if approved and implemented, may be substantial.

W. H. Sammis Plant

In 1999 and 2000, the EPA issued NOV or compliance orders to nine utilities alleging violations of the Clean Air Act based on operation and maintenance of 44 power plants, including the W. H. Sammis Plant, which was owned at that time by OE and Penn. In addition, the DOJ filed eight civil complaints against various investor-owned utilities, including a complaint against OE and Penn in the U.S. District Court for the Southern District of Ohio. These cases are referred to as the New Source Review cases.

On March 18, 2005, OE and Penn announced that they had reached a settlement with the EPA, the DOJ and three states (Connecticut, New Jersey, and New York) that resolved all issues related to the New Source Review litigation. This settlement agreement, which is in the form of a consent decree, was approved by the Court on July 11, 2005, and requires reductions of NO_X and SO_2 emissions at the W. H. Sammis Plant and other FES coal-fired plants through the installation of pollution control devices and provides for stipulated penalties for failure to install and operate such pollution controls in accordance with that agreement. Consequently, if FirstEnergy fails to install such pollution control devices, for any reason, including, but not limited to, the failure of any third-party contractor to timely meet its delivery obligations for such devices, FirstEnergy could be exposed to penalties under the Sammis NSR Litigation consent decree. Capital expenditures necessary to complete requirements of the Sammis NSR Litigation are currently estimated to be $1.5 billion ($400 million of which is expected to be spent in 2007, with the largest portion of the remaining $1.1 billion expected to be spent in 2008 and 2009).

The Sammis NSR Litigation consent decree also requires us to spend up to $25 million toward environmentally beneficial projects, $14 million of which is satisfied by entering into 93 MW (or 23 MW if federal tax credits are not applicable) of wind energy purchased power agreements with a 20-year term. An initial 16 MW of the 93 MW consent decree obligation was satisfied during 2006.

On August 26, 2005, FGCO entered into an agreement with Bechtel Power Corporation under which Bechtel will engineer, procure, and construct air quality control systems for the reduction of SO_2 emissions. FGCO also entered into an agreement with B&W on August 25, 2006 to supply flue gas desulfurization systems for the reduction of SO_2 emissions. Selective Catalytic Reduction (SCR) systems for the reduction of NO_X emissions also are being installed at the W.H. Sammis Plant under a 1999 agreement with B&W.

OE and Penn agreed to pay a civil penalty of $8.5 million. Results for the first quarter of 2005 included the penalties paid by OE and Penn of $7.8 million and $0.7 million, respectively. OE and Penn also recognized liabilities in the first quarter of 2005 of $9.2 million and $0.8 million, respectively, for probable future cash contributions toward environmentally beneficial projects.

Climate Change

In December 1997, delegates to the United Nations' climate summit in Japan adopted an agreement, the Kyoto Protocol, to address global warming by reducing the amount of man-made GHG emitted by developed countries by 5.2% from 1990 levels between 2008 and 2012. The United States signed the Kyoto Protocol in 1998 but it failed to receive the two-thirds vote required for ratification by the United States Senate. However, the Bush administration has committed the United States to a voluntary climate change strategy to reduce domestic GHG intensity – the ratio of emissions to economic output – by 18% through 2012. The EPACT established a Committee on Climate Change Technology to coordinate federal climate change activities and promote the development and deployment of GHG reducing technologies.

FirstEnergy 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. The CO_2 emissions per KWH of electricity generated by FirstEnergy is lower than many regional competitors due to its diversified generation sources, which include 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 FirstEnergy's plants. In addition, Ohio, New Jersey and Pennsylvania have water quality standards applicable to FirstEnergy's 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 Section 316(b) of the Clean Water Act 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 life is drawn into a facility's cooling water system. On January 26, 2007, the federal Court of Appeals for the Second Circuit remanded portions of the rulemaking dealing with impingement mortality and entrainment back to EPA for further rulemaking and eliminated the restoration option from EPA's regulations. FirstEnergy is conducting comprehensive demonstration studies, due in 2008, to determine the operational measures or equipment, if any, necessary for compliance by its facilities with the performance standards. FirstEnergy is unable to predict the outcome of such studies or changes in these requirements from the remand to EPA. Depending on the outcome of such studies and EPA's further rulemaking, the future cost of compliance with these standards may require material capital expenditures.

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.

Under NRC regulations, FirstEnergy must ensure that adequate funds will be available to decommission its nuclear facilities. As of December 31, 2006, FirstEnergy had approximately $1.4 billion invested in external trusts to be used for the decommissioning and environmental remediation of Davis-Besse, Beaver Valley and Perry. As part of the application to the NRC to transfer the ownership of these nuclear facilities to NGC, FirstEnergy agreed to contribute another $80 million to these trusts by 2010. Consistent with NRC guidance, utilizing a "real" rate of return on these funds of approximately 2% over inflation, these trusts are expected to exceed the minimum decommissioning funding requirements set by the NRC. Conservatively, these estimates do not include any rate of return that the trusts may earn over the 20-year plant useful life extensions that FirstEnergy plans to seek for these facilities.

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, 2006, based on estimates of the total costs of cleanup, the Companies' proportionate responsibility for such costs and the financial ability of other unaffiliated 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. Total liabilities of approximately $88 million have been accrued through December 31, 2006.

(E) 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 of New Jersey's 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 Division 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 JCP&L transformers in Red Bank, New Jersey. In 2005, JCP&L renewed its motion to decertify the class based on a very limited number of class members who incurred damages and also filed a motion for summary judgment on the remaining plaintiffs' claims for negligence, breach of contract and punitive damages. In July 2006, the New Jersey Superior Court dismissed the punitive damage claim and again decertified the class based on the fact that a vast majority of the class members did not suffer damages and those that did would be more appropriately addressed in individual actions. Because it effectively terminates this class action, plaintiffs appealed this ruling to the New Jersey Appellate Division, where the matter is currently pending. FirstEnergy is unable to predict the outcome of these matters and no liability has been accrued as of December 31, 2006.

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. The U.S. – Canada Power System Outage Task Force's final report in April 2004 on the outages concluded, among other things, that the problems leading to the outages began in FirstEnergy's Ohio service area. Specifically, the final report concluded, 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 Web site (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 contained 46 "recommendations to prevent or minimize the scope of future blackouts." Forty-five of those recommendations related to broad industry or policy matters while one, including subparts, related to activities the Task Force recommended be undertaken by FirstEnergy, MISO, PJM, ECAR, and other parties to correct the causes of the August 14, 2003 power outages. FirstEnergy implemented several initiatives, both prior to and since the August 14, 2003 power outages, which were independently verified by NERC as complete in 2004 and were consistent with these and other recommendations and collectively enhance the reliability of its electric system. FirstEnergy's implementation of these recommendations in 2004 included completion of the Task Force recommendations that were directed toward FirstEnergy. FirstEnergy is also 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. The FERC or other applicable government agencies and reliability coordinators may, however, take a different view as to recommended enhancements or may recommend additional enhancements in the future that could require additional material expenditures.

FirstEnergy companies also are defending five separate complaint cases before the PUCO relating to the August 14, 2003 power outages. Two cases were originally filed in Ohio State courts but were subsequently dismissed for lack of subject matter jurisdiction and further appeals were unsuccessful. In these cases the individual complainants—three in one case and four in the other—sought to represent others as part of a class action. The PUCO dismissed the class allegations, stating that its rules of practice do not provide for class action complaints. Three other pending PUCO complaint cases were filed by various insurance carriers either in their own name as subrogees or in the name of their insured. In each of these three cases, the carrier seeks reimbursement from various FirstEnergy companies (and, in one case, from PJM, MISO and American Electric Power Company, Inc., as well) for claims paid to insureds for damages allegedly arising as a result of the loss of power on August 14, 2003. The listed insureds in these cases, in many instances, are not customers of any FirstEnergy company. A sixth case involving the claim of a non-customer seeking reimbursement for losses incurred when its store was burglarized on August 14, 2003 was dismissed. On March 7, 2006, the PUCO issued a ruling, consolidating all of the pending outage cases for hearing; limiting the litigation to service-related claims by customers of the Ohio operating companies; dismissing FirstEnergy as a defendant; and ruling that the U.S.-Canada Power System Outage Task Force Report was not admissible into evidence. In response to a motion for rehearing filed by one of the claimants, the PUCO ruled on April 26, 2006 that the insurance company claimants, as insurers, may prosecute their claims in their name so long as they also identify the underlying insured entities and the Ohio utilities that provide their service. The PUCO denied all other motions for rehearing. The plaintiffs in each case have since filed amended complaints and the named FirstEnergy companies have answered and also have filed a motion to dismiss each action. On September 27, 2006, the PUCO dismissed certain parties and claims and otherwise ordered the complaints to go forward to hearing. The cases have been set for hearing on October 16, 2007.

On October 10, 2006, various insurance carriers refiled a complaint in Cuyahoga County Common Pleas Court seeking reimbursement for claims paid to numerous insureds who allegedly suffered losses as a result of the August 14, 2003 outages. All of the insureds appear to be non-customers. The plaintiff insurance companies are the same claimants in one of the pending PUCO cases. FirstEnergy, the Ohio Companies and Penn were served on October 27, 2006. On January 18, 2007, the Court granted the Companies' motion to dismiss the case. It is unknown whether or not the matter will be further appealed. No estimate of potential liability is available for any of these cases.

FirstEnergy was also named, along with several other entities, in a complaint in New Jersey State Court. The allegations against FirstEnergy were based, in part, on an alleged failure to protect the citizens of Jersey City from an electrical power outage. None of FirstEnergy's subsidiaries serve customers in Jersey City. A responsive pleading has been filed. On April 28, 2006, the Court granted FirstEnergy's motion to dismiss. The plaintiff has not appealed.

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. Although FirstEnergy is unable to predict the impact of these proceedings, 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, results of operations and cash flows.

Nuclear Plant Matters

On January 20, 2006, FENOC announced that it had entered into a deferred prosecution agreement with the U.S. Attorney's Office for the Northern District of Ohio and the Environmental Crimes Section of the Environment and Natural Resources Division of the DOJ related to FENOC's communications with the NRC during the fall of 2001 in connection with the reactor head issue at the Davis-Besse Nuclear Power Station. Under the agreement, the United States acknowledged FENOC's extensive corrective actions at Davis-Besse, FENOC's cooperation during investigations by the DOJ and the NRC, FENOC's pledge of continued cooperation in any related criminal and administrative investigations and proceedings, FENOC's acknowledgement of responsibility for the behavior of its employees, and its agreement to pay a monetary penalty. The DOJ agreed to refrain from seeking an indictment or otherwise initiating criminal prosecution of FENOC for all conduct related to the statement of facts attached to the deferred prosecution agreement, as long as FENOC remained in compliance with the agreement, which FENOC has done. FENOC paid a monetary penalty of $28 million (not deductible for income tax purposes) which reduced FirstEnergy's earnings by $0.09 per common share in the fourth quarter of 2005. The deferred prosecution agreement expired on December 31, 2006.

On April 21, 2005, the NRC issued a NOV and proposed a $5.45 million civil penalty related to the degradation of the Davis-Besse reactor vessel head issue discussed above. FirstEnergy accrued $2 million for a potential fine prior to 2005 and accrued the remaining liability for the proposed fine during the first quarter of 2005. On September 14, 2005, FENOC filed its response to the NOV with the NRC. FENOC accepted full responsibility for the past failure to properly implement its boric acid corrosion control and corrective action programs. The NRC NOV indicated that the violations do not represent current licensee performance. FirstEnergy paid the penalty in the third quarter of 2005. On January 23, 2006, FENOC supplemented its response to the NRC's NOV on the Davis-Besse head degradation to reflect the deferred prosecution agreement that FENOC had reached with the DOJ.

On August 12, 2004, the NRC notified FENOC that it would increase its regulatory oversight of the Perry Nuclear Power Plant as a result of problems with safety system equipment over the preceding two years and the licensee's failure to take prompt and corrective action. On April 4, 2005, the NRC held a public meeting to discuss FENOC's performance at the Perry Nuclear Power Plant as identified in the NRC's annual assessment letter to FENOC. Similar public meetings are held with all nuclear power plant licensees following issuance by the NRC of their annual assessments. According to the NRC, overall the Perry Nuclear Power Plant operated "in a manner that preserved public health and safety" even though it remained under heightened NRC oversight. During the public meeting and in the annual assessment, the NRC indicated that additional inspections will continue and that the plant must improve performance to be removed from the Multiple/Repetitive Degraded Cornerstone Column of the Action Matrix.

On September 28, 2005, the NRC sent a CAL to FENOC describing commitments that FENOC had made to improve the performance at the Perry Nuclear Power Plant and stated that the CAL would remain open until substantial improvement was demonstrated. The CAL was anticipated as part of the NRC's Reactor Oversight Process. In the NRC's 2005 annual assessment letter dated March 2, 2006 and associated meetings to discuss the performance of the Perry Nuclear Power Plant on March 14, 2006, the NRC again stated that the Perry Nuclear Power Plant continued to operate in a manner that "preserved public health and safety." However, the NRC also stated that increased levels of regulatory oversight would continue until sustained improvement in the performance of the facility was realized. If performance does not improve, the NRC has a range of options under the Reactor Oversight Process, from increased oversight to possible impact to the plant's operating authority. Although FirstEnergy is unable to predict the impact of the ultimate disposition of this matter, it could have a material adverse effect on FirstEnergy's or its subsidiaries' financial condition, results of operations and cash flows.

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 other potentially material items not otherwise discussed above are described below.

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 now repealed 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 subpoena asking for documents relating to issues raised during the SEC's PUHCA examination. On August 24, 2005, additional information was requested regarding Davis-Besse-related disclosures, which has been provided. FirstEnergy has cooperated fully with the informal inquiry and continues to do so with the formal investigation.

On August 22, 2005, a class action complaint was filed against OE in Jefferson County, Ohio Common Pleas Court, seeking compensatory and punitive damages to be determined at trial based on claims of negligence and eight other tort counts alleging damages from W.H. Sammis Plant air emissions. The two named plaintiffs are also seeking injunctive relief to eliminate harmful emissions and repair property damage and the institution of a medical monitoring program for class members. On October 18, 2006, the Ohio Supreme Court transferred this case to a Tuscarawas County Common Pleas Court judge due to concerns over potential class membership by the Jefferson County Common Pleas Court.

JCP&L's bargaining unit employees filed a grievance challenging JCP&L's 2002 call-out procedure that required bargaining unit employees to respond to emergency power outages. On May 20, 2004, an arbitration panel concluded that the call-out procedure violated the parties' collective bargaining agreement. At the conclusion of the June 1, 2005 hearing, the arbitration panel decided not to hear testimony on damages and closed the proceedings. On September 9, 2005, the arbitration panel issued an opinion to award approximately $16 million to the bargaining unit employees. On February 6, 2006, a federal district court granted a union motion to dismiss, as premature, a JCP&L appeal of the award filed on October 18, 2005. JCP&L intends to re-file an appeal again in federal district court once the damages associated with this case are identified at an individual employee level. JCP&L recognized a liability for the potential $16 million award in 2005.

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

15. FIRSTENERGY INTRA-SYSTEM GENERATION ASSET TRANSFERS

In 2005, the Ohio Companies and Penn entered into certain agreements implementing a series of intra-system generation asset transfers that were completed in the fourth quarter of 2005. The asset transfers resulted in the respective undivided ownership interests of the Ohio Companies and Penn in FirstEnergy's nuclear and non-nuclear generation assets being owned by NGC and FGCO, respectively. The generating plant interests transferred do not include leasehold interests of CEI, TE and OE in certain of the plants that are currently subject to sale and leaseback arrangements with non-affiliates.

On October 24, 2005, the Ohio Companies and Penn completed the intra-system transfer of non-nuclear generation assets to FGCO. Prior to the transfer, FGCO, as lessee under a Master Facility Lease with the Ohio Companies and Penn, leased, operated and maintained the non-nuclear generation assets that it now owns. The asset transfers were consummated pursuant to FGCO's purchase option under the Master Facility Lease.

On December 16, 2005, the Ohio Companies and Penn completed the intra-system transfer of their respective ownership in the nuclear generation assets to NGC through, in the case of OE and Penn, an asset spin-off in the form of a dividend and, in the case of CEI and TE, a sale at net book value.

On December 28, 2006, the NRC approved the transfer of ownership in NGC from FirstEnergy to FES. Effective December 31, 2006, NGC is a wholly owned subsidiary of FES and second tier subsidiary of FirstEnergy. FENOC continues to operate and maintain the nuclear generation assets.

These transactions were undertaken pursuant to the Ohio Companies' and Penn's restructuring plans that were approved by the PUCO and the PPUC, respectively, under applicable Ohio and Pennsylvania electric utility restructuring legislation. Consistent with the restructuring plans, generation assets that had been owned by the Ohio Companies and Penn were required to be separated from the regulated delivery business of those companies through transfer or sale to a separate corporate entity. The transactions essentially completed the divestitures of owned assets contemplated by the restructuring plans by transferring the ownership interests to NGC and FGCO without impacting the operation of the plants. The transfers were intracompany transactions and, therefore, had no impact on our consolidated results.

16. SEGMENT INFORMATION

FirstEnergy has two reportable operating segments: regulated services and power supply management services. None of the aggregate "Other" segments individually meet the criteria to be considered a reportable segment. The regulated services segment consists of the regulated sale of electricity and distribution and transmission services by FirstEnergy's eight utility subsidiaries in Ohio, Pennsylvania and New Jersey. The power supply management services segment primarily consists of the subsidiaries (FES, FGCO, NGC and FENOC) that sell electricity in deregulated markets and operate and own generation facilities. "Other" consists of telecommunications services and the recently sold MYR (a construction service company) and retail natural gas operations (see Note 8). The assets and revenues for the other business operations are below the quantifiable threshold for operating segments for separate disclosure as "reportable operating segments."

The regulated services segment designs, constructs, operates and maintains FirstEnergy's regulated transmission and distribution systems. Its revenues are primarily derived from the delivery of electricity and transition cost recovery. Assets of the regulated services segment as of December 31, 2004 included generating units that were leased or whose output had been sold to the power supply management services segment (see Note 15). The regulated services segment's internal revenues in 2005 and 2004 represented the rental revenues for the generating unit leases which ceased in the fourth quarter of 2005 as a result of the intra-system asset transfers (see Note 15).

The power supply management services segment supplies the electric power needs of FirstEnergy's end-use customers through retail and wholesale arrangements, including regulated retail sales to meet all or a portion of the PLR requirements of its Ohio and Pennsylvania utility subsidiaries and competitive retail sales to customers primarily in Ohio, Pennsylvania, Maryland and Michigan. This business segment owns and operates FirstEnergy's generating facilities and purchases electricity to meet sales obligations (see Note 15). The segment's net income is primarily derived from all electric generation sales revenues less the related costs of electricity generation, including purchased power and net transmission, congestion and ancillary costs charged by PJM and MISO to deliver energy to retail customers.

Segment reporting in 2005 and 2004 has been revised to conform to the current year business segment organization and operations and the reclassification of discontinued operations sold in 2006 (See Note 2(J)). Changes in the current year operations reporting reflected in the revised 2005 and 2004 segment reporting primarily includes the transfer of retail transmission revenues and PJM/MISO transmission revenues and expenses associated with serving electricity load previously included in the regulated services segment to the power supply management services segment. In addition, as a result of the 2005 Ohio tax legislation reducing the effective state income tax rate, the calculated composite income tax rates used in the two reportable segments' results have been changed to 40% from the tax rates previously reported in their 2005 and 2004 segment results. The net amounts of the changes in the 2005 and 2004 reportable segments' income taxes reclassifications have been correspondingly offset in the respective year's "Reconciling Adjustments" results. FSG, which had been classified as held for sale as of December 31, 2005 (See Note 2(J)), completed the sale of its five remaining subsidiaries in 2006. Its assets and results for 2006, 2005 and 2004 are combined in the "Other" segments in this report, as the remaining business does not meet the criteria of a reportable segment. Interest expense on holding company debt and corporate support services revenues and expenses are included in "Reconciling Items."

Segment Financial Information	Regulated Services	Power Supply Management Services	Other	Reconciling Adjustments	Consolidated
		(In millions)			
2006					
External revenues	$4,441	$7,029	$103	$(72)	$11,501
Internal revenues	–	–	–	–	–
Total revenues	4,441	7,029	103	(72)	11,501
Depreciation and amortization	1,001	(70)	4	22	957
Investment income	270	36	1	(158)	149
Net interest charges	410	215	6	71	702
Income taxes	632	310	(20)	(127)	795
Income from continuing operations	932	465	44	(183)	1,258
Discontinued operations	–	–	(4)	–	(4)
Net income	932	465	40	(183)	1,254
Total assets	23,336	6,976	297	587	31,196
Total goodwill	5,873	24	1	–	5,898
Property additions	633	644	1	37	1,315
2005					
External revenues	$5,155	$6,067	$115	$ 21	$11,358
Internal revenues	270	–	–	(270)	–
Total revenues	5,425	6,067	115	(249)	11,358
Depreciation and amortization	1,483	(46)	2	25	1,464
Investment income	217	–	–	–	217
Net interest charges	389	54	6	207	656
Income taxes	784	(28)	12	(19)	749
Income (loss) from continuing operations	1,174	(41)	14	(268)	879
Discontinued operations	–	–	12	–	12
Cumulative effect of accounting change	(21)	(9)	–	–	(30)
Net income (loss)	1,153	(50)	26	(268)	861
Total assets	23,975	6,556	605	705	31,841
Total goodwill	5,932	24	54	–	6,010
Property additions	788	375	8	37	1,208
2004					
External revenues	$4,885	$6,510	$201	$ 4	$11,600
Internal revenues	318	–	–	(318)	–
Total revenues	5,203	6,510	201	(314)	11,600
Depreciation and amortization	1,422	35	3	34	1,494
Investment income	205	–	–	–	205
Net interest charges	363	37	15	251	666
Income taxes	698	75	(24)	(68)	681
Income from continuing operations	1,047	112	38	(290)	907
Discontinued operations	–	–	(29)	–	(29)
Net income	1,047	112	9	(290)	878
Total assets	28,308	1,488	760	479	31,035
Total goodwill	5,951	24	75	–	6,050
Property additions	572	246	7	21	846

Reconciling adjustments to segment operating results from internal management reporting to consolidated external financial reporting primarily consist 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
2006	$10,671	$48
2005	10,546	77
2004	10,831	91

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

17. NEW ACCOUNTING STANDARDS AND INTERPRETATIONS

SFAS 159 – " The Fair Value Option for Financial Assets and Financial Liabilities – Including an amendment of FASB Statement No. 115"

In February 2007, the FASB issued SFAS 159, which provides companies with an option to report selected financial assets and liabilities at fair value. The Standard requires companies to provide additional information that will help investors and other users of financial statements to more easily understand the effect of the company's choice to use fair value on its earnings. The Standard also requires companies to display the fair value of those assets and liabilities for which the company has chosen to use fair value on the face of the balance sheet. This guidance does not eliminate disclosure requirements included in other accounting standards, including requirements for disclosures about fair value measurements included in SFAS 157, *Fair Value Measurements*, and SFAS 107, *Disclosures about Fair Value of Financial Instruments*. FirstEnergy is currently evaluating the impact of this Statement on its financial statements.

FSP EITF 00-19-2 – "Accounting for Registration Payment Arrangements"

In December 2006, the FASB issued FSP EITF 00-19-2, which addresses an issuer's accounting for registration payment arrangements. This guidance specifies that the contingent obligation to make future payments or otherwise transfer consideration under a registration payment arrangement, whether issued as a separate agreement or included as a provision of a financial instrument or other agreement, should be separately recognized and measured in accordance with SFAS 5, *Accounting for Contingencies*. This FSP shall be effective immediately for registration payment arrangements and the financial instruments subject to those arrangements that are entered into or modified subsequent to the date of issuance of this FSP. For arrangements that were entered into prior to the issuance of this FSP, this guidance shall be effective for financial statements issued for fiscal years beginning after December 15, 2006, and interim periods within those fiscal years. FirstEnergy does not expect this FSP to have a material effect on its financial statements.

EITF 06-5 – "Accounting for Purchases of Life Insurance-Determining the Amount That Could Be Realized in Accordance with FASB Technical Bulletin No. 85-4, Accounting for Purchases of Life Insurance"

In September 2006, the EITF reached a consensus on Issue 06-5 concluding that a policyholder should consider any additional amounts included in the contractual terms of the policy in determining the amount that could be realized under the insurance contract. Contractual limitations should be considered when determining the realizable amounts. Amounts that are recoverable by the policyholder at the discretion of the insurance company should be excluded from the amount that could be realized. Recoverable amounts in periods beyond one year from the surrender of the policy should be discounted in accordance with APB Opinion No. 21, "Interest on Receivables and Payables." Consensus was also reached that a policyholder should determine the amount that could be realized under the insurance contract assuming the surrender of an individual-life by individual-life policy (or certificate by certificate in a group policy). Any amount that would ultimately be realized by the policyholder upon the assumed surrender of the final policy (or final certificate) should be included in the amount that could be realized under the insurance contract. The EITF also concluded that a policyholder should not discount the cash surrender value component of the amount that could be realized when contractual restrictions on the ability to surrender a policy exist. However, if the contractual limitations prescribe that the cash surrender value component of the amount that could be realized is a fixed amount, then the amount that could be realized should be discounted in accordance with APB Opinion No. 21. This Issue is effective for fiscal years beginning after December 15, 2006. FirstEnergy does not expect this EITF to have a material impact on its financial statements.

SFAS 157 – "Fair Value Measurements"

In September 2006, the FASB issued SFAS 157, that establishes how companies should measure fair value when they are required to use a fair value measure for recognition or disclosure purposes under GAAP. This Statement addresses the need for increased consistency and comparability in fair value measurements and for expanded disclosures about fair value measurements. The key changes to current practice are: (1) the definition of fair value which focuses on an exit price rather than entry price; (2) the methods used to measure fair value such as emphasis that fair value is a market-based measurement, not an entity-specific measurement, as well as the inclusion of an adjustment for risk, restrictions and credit standing; and (3) the expanded disclosures about fair value measurements. This Statement is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those years. FirstEnergy is currently evaluating the impact of this Statement on its financial statements.

FSP FIN 46(R)-6 – "Determining the Variability to Be Considered in Applying FASB interpretation No. 46(R)"

In April 2006, the FASB issued FSP FIN 46(R)-6 that addresses how a reporting enterprise should determine the variability to be considered in applying FASB interpretation No. 46 (revised December 2003). FirstEnergy adopted FIN 46(R) in the first quarter of 2004, consolidating VIEs when FirstEnergy or one of its subsidiaries is determined to be the VIE's primary beneficiary. The variability that is considered in applying interpretation 46(R) affects the determination of (a) whether the entity is a VIE; (b) which interests are variable interests in the entity; and (c) which party, if any, is the primary beneficiary of the VIE. This FSP states that the variability to be considered shall be based on an analysis of the design of the entity, involving two steps:

Step 1: Analyze the nature of the risks in the entity

Step 2: Determine the purpose(s) for which the entity was created and determine the variability the entity is designed to create and pass along to its interest holders.

After determining the variability to consider, the reporting enterprise can determine which interests are designed to absorb that variability. The guidance in this FSP is applied prospectively to all entities (including newly created entities) with which that enterprise first becomes involved and to all entities previously required to be analyzed under interpretation 46(R) when a reconsideration event has occurred after July 1, 2006. FirstEnergy does not expect this Statement to have a material impact on its financial statements.

FIN 48 – "Accounting for Uncertainty in Income Taxes – an interpretation of FASB Statement No. 109"

In June 2006, the FASB issued FIN 48 which clarifies the accounting for uncertainty in income taxes recognized in an enterprise's financial statements in accordance with FASB Statement No. 109, "Accounting for Income Taxes." This interpretation prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken on a tax return. This interpretation also provides guidance on derecognition, classification, interest, penalties, accounting in interim periods, disclosure and transition. The evaluation of a tax position in accordance with this interpretation will be a two-step process. The first step will determine if it is more likely than not that a tax position will be sustained upon examination and should therefore be recognized. The second step will measure a tax position that meets the more likely than not recognition threshold to determine the amount of benefit to recognize in the financial statements. This interpretation is effective for fiscal years beginning after December 15, 2006. FirstEnergy is currently evaluating the impact of this Statement. The Company does not expect this Statement to have a material impact on its financial statements.

18. SUMMARY OF QUARTERLY FINANCIAL DATA (UNAUDITED)

The following summarizes certain consolidated operating results by quarter for 2006 and 2005. Certain financial results have been reclassified to discontinued operations from amounts previously reported due to the divestiture of certain non-core businesses in 2006 as discussed in Note 2(J).

Three Months Ended	March 31, 2006	June 30, 2006	Sept. 30, 2006	Dec. 31, 2006
	(In millions, except per share amounts)			
Revenues	$2,705	$2,751	$3,365	$2,680
Expenses	2,233	2,081	2,505	2,076
Operating Income	472	670	860	604
Other Expense	117	142	134	160
Income From Continuing Operations Before Income Taxes	355	528	726	444
Income Taxes	136	216	274	170
Income From Continuing Operations	219	312	452	274
Discontinued Operations (Net of Income Taxes) (Note 2(J))	2	(8)	2	–
Net Income	$ 221	$ 304	$ 454	$ 274
Basic Earnings Per Share of Common Stock:				
Income From Continuing Operations	$ 0.67	$ 0.94	$ 1.41	$ 0.85
Discontinued Operations	–	(0.02)	–	–
Net Earnings Per Basic Share	$ 0.67	$ 0.92	$ 1.41	$ 0.85
Diluted Earnings Per Share of Common Stock:				
Income From Continuing Operations	$ 0.67	$ 0.93	$ 1.40	$ 0.84
Discontinued Operations	–	(0.02)	–	–
Net Earnings Per Diluted Share	$ 0.67	$ 0.91	$ 1.40	$ 0.84

Three Months Ended	March 31, 2005	June 30, 2005	Sept. 30, 2005	Dec. 31, 2005
	(In millions, except per share amounts)			
Revenues	$2,627	$2,678	$3,333	$2,721
Expenses	2,234	2,146	2,692	2,220
Operating Income	393	532	641	501
Other Expense	129	114	75	122
Income From Continuing Operations Before Income Taxes	264	418	566	379
Income Taxes	122	238	236	153
Income From Continuing Operations	142	180	330	226
Discontinued Operations (Net of Income Taxes) (Note 2(J))	18	(2)	2	(6)
Cumulative Effect of a Change in Accounting Principle (Net of Income Taxes) (Note 2(K))	–	–	–	(30)
Net Income	$ 160	$ 178	$332	$ 190
Basic Earnings Per Share of Common Stock:				
Income From Continuing Operations	$ 0.43	$ 0.55	$ 1.00	$ 0.69
Discontinued Operations (Note 2(J))	0.06	(0.01)	0.01	(0.02)
Cumulative Effect of a Change in Accounting Principle	–	–	–	(0.09)
Net Earnings Per Basic Share	$ 0.49	$ 0.54	$ 1.01	$ 0.58
Diluted Earnings Per Share of Common Stock:				
Income From Continuing Operations	$ 0.43	$ 0.55	$ 1.00	$ 0.69
Discontinued Operations	0.05	(0.01)	0.01	(0.02)
Cumulative Effect of a Change in Accounting Principle	–	–	–	(0.09)
Net Earnings Per Diluted Share	$ 0.48	$ 0.54	$ 1.01	$ 0.58

Results for the fourth quarter of 2005 included a $30 million after-tax ($0.09 per share) cumulative effect adjustment associated with the adoption of FIN 47 (see Note 12), a $9 million (with no corresponding tax impact) ($0.03 per share) non-cash charge for impairment of goodwill of MYR as required by SFAS 142 (see Note 2(H)) and a $28 million (which is not deductible for income tax purposes) ($0.09 per share) charge related to the Davis-Besse DOJ and NRC fines (see Note 14). Net income for that quarter also included a $15 million after-tax ($0.05 per share) charge relating to prior periods as a result of a JCP&L tax audit adjustment applicable to prior quarters in 2005 and prior years. Management concluded that the adjustment was not material to FirstEnergy's reported consolidated results of operations for any quarter of 2005, nor was it material to the consolidated balance sheets and consolidated cash flows for any of those quarters.

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