FirstEnergy

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April 6, 2006

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DB-Serial No.-3255
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Mr. Ira Dinitz
U.S. Nuclear Regulatory Commission
Office of Nuclear Reactor Regulation
Washington, D.C. 20555

Dear Mr. Dinitz;

Re: Docket Nos. 50-346, 50-440, 50-412, 50-334
Retrospective Premium Guarantee

Enclosed you will find the 2005 FirstEnergy Corp. Annual Report. This is in addition to the 2006 Internal Cash Flow Projection sent February 17, 2006 and completes the requirements for the Retrospective Premium Guarantee.

Very truly yours,

Randy Scilla

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2005 ANNUAL REPORT

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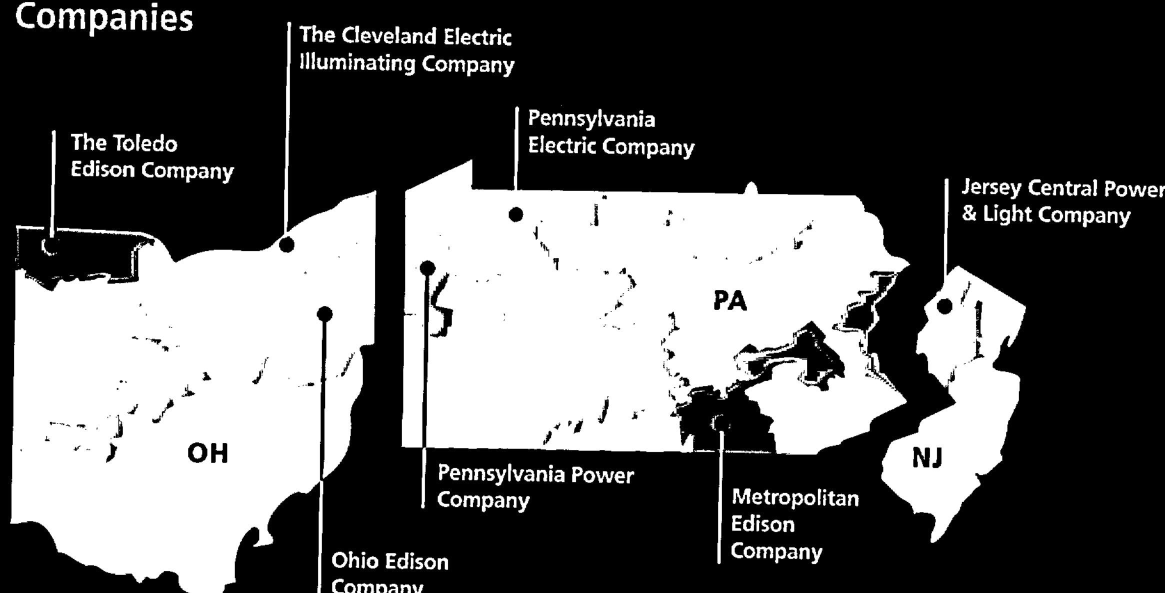
On The Cover: A $12-million renovation of our System Control Center near Akron, Ohio, gives our dispatchers state-of-the-art technology for monitoring and operating our transmission system in Ohio and western Pennsylvania.

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.

Electric Utility Operating Companies



FINANCIAL HIGHLIGHTS

(Dollars in millions, except per share amounts)

	2005	2004
Total revenues	**$11,989**	$12,060
Income before discontinued operations and cumulative effect of accounting change*	**$ 873**	$ 896
Net income	**$ 861**	$ 878
Basic earnings per common share:		
Before discontinued operations and cumulative effect of accounting change	**$ 2.66**	$ 2.74
After discontinued operations and cumulative effect of accounting change	**$ 2.62**	$ 2.68
Diluted earnings per common share:		
Before discontinued operations and cumulative effect of accounting change	**$ 2.65**	$ 2.73
After discontinued operations and cumulative effect of accounting change	**$ 2.61**	$ 2.67
Dividends paid per common share**	**$ 1.67**	$ 1.50
Book value per common share	**$ 27.98**	$ 26.20
Net cash from operations	**$ 2,220**	$ 1,892

** The 2005 and 2004 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 $0.45 was paid on March 1, 2006, increasing the indicated annual dividend rate to $1.80 per share.*

The following analysis reconciles basic earnings per share of common stock in 2005 and 2004 computed under generally accepted accounting principles (GAAP) to adjusted basic earnings per share excluding unusual items in both years (non-GAAP)*.

	2005	2004
Adjusted basic earnings per share:		
Basic earnings per share (GAAP)	**$2.62**	$2.68
Cumulative effect of accounting change	**.09**	–
Ohio/New Jersey income tax adjustments	**.19**	–
EPA settlement	**.04**	–
Davis-Besse DOJ penalty and NRC fines	**.10**	–
JCP&L arbitration decision	**.03**	–
JCP&L rate settlement	**(.05)**	–
Non-core asset sales/impairments	**(.02)**	.19
Davis-Besse extended outage impacts	**–**	.12
Class-action lawsuit settlement	**–**	.03
Other	**–**	.01
Adjusted basic earnings per share (non-GAAP*)	**$3.00**	$3.03

** Generally, a non-GAAP financial measure is a numerical measure of a company's historical or future financial performance, financial position, or cash flows that either excludes or includes amounts, or is subject to adjustment that have the effect of excluding or including amounts, that are not normally excluded or included in the most directly comparable measure calculated and presented in accordance with accounting principles generally accepted in the United States, or GAAP.*

Forward-Looking Statements

This annual report includes forward-looking statements based on information currently available to management. Such statements are subject to certain risks and uncertainties. These statements typically contain, but are not limited to, the terms "anticipate," "potential," "expect," "believe," "estimate" and similar words. Actual results may differ materially due to the speed and nature of increased competition and deregulation in the electric utility industry, economic or weather conditions affecting future sales and margins, changes in markets for energy services, changing energy and commodity market prices, replacement power costs being higher than anticipated or inadequately hedged, 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), the repeal of the Public Utility Holding Company Act of 1935 and the legal and regulatory changes resulting from the implementation of the Energy Policy Act of 2005, the uncertainty of the timing and amounts of the capital expenditures (including that such amounts could be higher than anticipated) or levels of emission reductions related to the settlement agreement 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 United States Attorney's Office, the Nuclear Regulatory Commission and the various state public utility commissions as disclosed in our Securities and Exchange Commission filings, generally, and with respect to the Davis-Besse Nuclear Power Station outage and heightened scrutiny at the Perry Nuclear Power Plant in particular, the timing and outcome of future rate proceedings in Pennsylvania, the continuing availability and operation of generating units, the ability of our generating units to continue to operate at, or near full capacity, our inability to accomplish or realize anticipated benefits from strategic goals (including employee workforce factors), the anticipated benefits from our voluntary pension plan contributions, our ability to improve electric commodity margins and to experience growth in the distribution business, our ability to access the public securities and other capital markets 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, circumstances which may lead management to seek, or the Board of Directors to grant, in each case in its sole discretion, authority for the implementation of a share repurchase program in the future, the risks and other factors discussed from time to time in our Securities and Exchange Commission filings, and other similar factors. Dividends declared from time to time during any annual period may in aggregate vary from the indicated amounts due to circumstances considered by the Board at the time of the actual declarations. Also, a security rating should not be viewed as a recommendation to buy, sell or hold securities and it may be subject to revision or withdrawal at any time. 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

"Based on the Company's performance, your Board of Directors increased the common stock dividend payment by 14.7 percent."

We made solid progress in 2005 and continued to position your Company for success in the years ahead. Our key accomplishments included:

- Increasing our common stock dividend payment by 14.7 percent;
- Achieving an investment-grade credit rating from Standard & Poor's for all of our debt and completing our debt-reduction program;
- Producing record electricity output from our generating units;
- Enhancing our reliability and customer service; and
- Gaining approval for our Rate Certainty Plan in Ohio and for our generation asset transfer.

These and other accomplishments reflect our overall strategy, which is focused on reinvesting in our business and continuous improvement. For example, we are upgrading our transmission and distribution system to improve service reliability; implementing new technologies and industry best practices to provide more responsive customer service; increasing generating capacity and maximizing the efficient utilization of our plants as we prepare for fully deregulated markets in Ohio and Pennsylvania; and maintaining an unwavering focus on safety. These actions will help enhance the long-term value of your investment in FirstEnergy.

Solid Financial Results

Our financial performance in 2005 was strong, particularly in the key areas of earnings, cash flow and debt reduction.

We produced four quarters of solid financial results, ending the year with basic earnings per share of $3.00 on a non-GAAP* basis, which reached the top of our 2005 guidance to the financial community of $2.85 to $3.00 per share. Net cash from operations increased to $2.2 billion – up from $1.9 billion in 2004. We also reduced our debt-to-capitalization ratio to approximately 56 percent, bringing this important metric to within our target range. In addition, we successfully completed the $4-billion debt-reduction program we started four years ago and regained our investment-grade credit rating for all of our debt.

We delivered a total return to investors – a measure of stock price appreciation plus reinvested dividends – of 28.5 percent in 2005. And, our five-year annualized total return ranks us 7th among the 64 U.S. investor-owned electric utilities that comprise the Edison Electric Institute's (EEI) index.

The increase in our stock price during 2005 added more than $3 billion of value to shareholders. Our performance led your Company to be named to the *Forbes* Platinum 400, also known as the list of "America's Best Big Companies."

Based on the Company's performance, your Board of Directors increased the common stock dividend payment by 14.7 percent. The Board also authorized our subsidiaries to make a voluntary contribution totaling $500 million to the pension plans in late 2005. While the pension contribution is expected to be accretive to earnings, it also increases the security of future plan benefits and represents a major investment in our employees and retirees.

Operational Improvements

In 2005, we took steps to improve our customer service and reliability. We launched our Accelerated Reliability Improvement Program – a five-year, $600-million effort that involves replacing and upgrading equipment on our transmission and distribution systems. These systemwide infrastructure improvements will enhance overall reliability at our utility companies well into the future.

In addition to spending about $150 million in 2005 on these types of improvements, we ordered 431 new vehicles – part of a multiyear fleet upgrade of more than 1,500 new vehicles – to ensure that our workforce has the equipment needed to get the job done safely and efficiently.

We're also installing new technologies that will benefit customer service and system performance. For example, our engineers developed a new storm-detection system to help safeguard distribution equipment during severe weather. The system automatically switches equipment during storms to protect key components from lightning and high winds. As a pilot project, we installed about 40 of these devices throughout our service area, and expect to move forward with full-scale implementation this year. These and other improvements are designed to reduce the frequency and duration of outages – as well as the number of customers affected when outages do occur.

Additionally, we completed a major renovation of our transmission system control center in Ohio, and we are in the process of rebuilding and consolidating distribution system control centers.

Our commitment to customer service received national recognition in February 2006, when we were named a recipient of EEI's Customer Service Award for being ranked among the top five electric companies by the country's leading retail chains.

On the generation front, we continued to optimize the performance of our plants. We set a total production record of 80.2 million megawatt-hours (MWH), surpassing the previous record set in 2004 by nearly 4 million MWH. Our coal-based generation fleet led the way with a record 49.9 million MWH, and our nuclear fleet produced 28.7 million MWH.

Our baseload fossil plants achieved a top-decile capacity factor for the year. And, Unit 2 at our 2,233-megawatt (MW) W. H. Sammis Plant reached 1,017 days of continuous operation, setting a national record for any single-boiler turbine generating unit.

At our largest coal-based facility, the 2,410-MW Bruce Mansfield Plant, we initiated a program to upgrade Unit 1's turbine and scrubber system – boosting net demonstrated capacity by about 50 MW while reducing emissions. Similar projects are slated for units 2 and 3 in the future. Together, these projects will provide enough capacity to increase the plant's output by up to 900,000 MWH annually.

Our nuclear fleet also made solid progress in 2005. Davis-Besse returned to the standard Nuclear Regulatory Commission oversight process in July. We also closed an important chapter on the Davis-Besse reactor head issue in January 2006, when we entered into a deferred prosecution agreement with the U.S. Attorney's Office and the U.S. Department of Justice.

We strengthened our nuclear management team and enhanced our fleet-management practices – steps designed to maintain a strong focus on nuclear safety and to achieve continued operational success.

As a result of our performance, the nuclear fleet garnered several awards and honors during the year. For example, Davis-Besse was recognized by the World Association of Nuclear Operators for achieving the lowest radiation exposure among all U.S. pressurized water reactors. And recently, Beaver Valley was awarded the 2005 World Class ALARA Performance Award by an international organization that tracks radiological exposure to employees at nuclear plants (ALARA is an acronym referring to keeping exposure *as low as reasonably achievable*).

For the year, Beaver Valley and Davis-Besse operated at better than 90-percent capacity factors, and our entire nuclear fleet averaged a 100-percent capacity factor during the months of June through December. Our fleet performance should further benefit from the completion of a major steam generator and reactor vessel head replacement this year at Beaver Valley Unit 1, the most substantial construction project at this unit since it was built in the 1970s. We also expect to complete nuclear plant capacity uprates between 2006 and 2009 that would add up to 156 MW to our non-emitting generating capacity.

Safety remains a top priority – both within our nuclear fleet and across our organization. We continued our efforts to strengthen the safety culture at all our nuclear facilities. We also achieved a Companywide Occupational Safety and Health Administration (OSHA) rate of 1.23 incidents per 100 employees in 2005, a 17-percent reduction compared with 2004, when our performance ranked just short of the top decile in our industry. Our fossil fleet posted an OSHA rate of 0.96 incidents per 100 employees, a 90-percent reduction from 2004, and our nuclear fleet recorded an OSHA rate of 0.41 incidents per 100 employees.

We are especially proud of our employees at Toledo Edison, who worked the entire year with only one incident and achieved an OSHA rate of 0.26, a best-ever rate for one of our operating companies.

Protecting the Environment

As one of the nation's leading energy companies, we are committed to help protect the environment while meeting our customers' need for safe, reliable electricity. We're proud of the progress we've made in this key area. In 2005, more than 60 percent of the electricity we produced came from our non-emitting nuclear fleet and scrubber-equipped units at our Mansfield Plant.

In one of our most ambitious projects to further reduce emissions, we have begun a multiyear installation of state-of-the-art air quality control systems at our Sammis Plant. This five-year project will cost approximately $1.5 billion and should allow for continued use of this essential asset for many years.

Over the next five years, FirstEnergy also expects to spend approximately $50 million on efforts to reduce greenhouse-gas (GHG) emissions, ranging from participation in the Global Roundtable on Climate Change, to partnerships with industry and government groups to develop technologies for GHG reduction, carbon-dioxide (CO_2) capture and storage, and advanced generation.

We're building on our leadership role in testing and developing environmental technologies. For example, we plan to install an Electro-Catalytic Oxidation (ECO®) system, developed through our partnership with Powerspan Corp., at our Bay Shore Plant in Oregon, Ohio. ECO, a multipollutant control technology for coal-based plants, is currently being demonstrated at our R. E. Burger Plant. Design engineering on the $125-million Bay Shore ECO system will begin this summer. Further development and testing will help determine whether ECO technology can be used to capture CO_2.

We plan to seek renewal of our licenses for nuclear and hydroelectric facilities. And, we have contracted to acquire additional wind power generation output, bringing the total we will have available to 360 MW.

"We set a total production record of 80.2 million megawatt-hours (MWH), surpassing the previous record set in 2004 by nearly 4 million MWH."

All of these strategic investments are designed to support our environmental programs, and where practical, increase generating capacity.

We also produced an Air Issues Report to shareholders that provides a comprehensive assessment of our past environmental performance as well as our future risks and mitigation efforts. FirstEnergy is better positioned than many electricity providers to operate in a carbon-constrained environment because of our diverse generation mix. The report is available on our Web site at *www.firstenergycorp.com/environmental.*

Building on Our Momentum

We took an important step toward strengthening our financial stability with the Rate Certainty Plan (RCP), which essentially maintains current electricity prices in Ohio through 2008.

The RCP enables us to collect certain fuel cost increases and to defer for future recovery certain other fuel and distribution-related expenses during the plan's term. While keeping electricity prices stable for our customers, the RCP provides us with more predictable revenues.

Also during the year, the New Jersey Board of Public Utilities approved settlement agreements involving rate filings, which had a positive impact on earnings. And, we intend to file a comprehensive rate proceeding during 2006 to address revenue requirements in Pennsylvania.

We also successfully completed an intra-system transfer of both nuclear and non-nuclear generation assets from our Ohio companies and Penn Power to separate, wholly owned generating company subsidiaries. This transfer enhances our flexibility as both Ohio and Pennsylvania move toward the end of their respective market development periods. And, it addresses corporate separation provisions of electric deregulation laws in both states.

Addressing Our Workforce Needs

Over the next several years, we anticipate hiring thousands of new employees to offset expected attrition as a significant portion of our workforce approaches retirement age. To support this process, we've established hiring goals for each business unit, expanded recruiting initiatives, and enhanced programs for introducing new employees to the Company. We're also focusing on ways to retain our dedicated, hardworking veterans.

In addition, we've developed a number of programs designed to help employees better understand our key strategies and goals. These programs enhance teamwork and provide employees with opportunities for personal development and advancement.

Positioned for Success

Your Company built on the achievements of recent years and delivered on goals established for 2005. With the ongoing efforts and expertise of our employees and your continued support, I look forward to achieving greater success in the years ahead.

Sincerely,

Anthony J Alexander

ANTHONY J. ALEXANDER
President and Chief Executive Officer

March 20, 2006

* This letter to shareholders contains a reference to non-GAAP basic earnings per share. This non-GAAP measure excludes amounts that are included in the most directly comparable measure calculated and presented in accordance with accounting principles generally accepted in the United States (GAAP). A reconciliation of 2005 GAAP basic earnings per share of $2.62, to 2005 non-GAAP basic earnings per share of $3.00, displaying the unusual items resulting in the difference between GAAP basic earnings per share and non-GAAP basic earnings per share, can be found in the accompanying Management's Discussion and Analysis of Results of Operations and Financial Condition on page 13.

Dear Shareholders

On behalf of your Board of Directors, I would like to congratulate our management and employees for another successful year.

Based on the Company's strong operational and financial performance, your Board voted to increase the common stock dividend payment twice in 2005, for a total increase of 14.7 percent. With the dividend increases and stock appreciation, your Company delivered a very favorable total shareholder return of 28.5 percent last year, approaching top-decile performance among the 64 member companies that make up the Edison Electric Institute's (EEI) index. We've been a consistent performer in this key metric, producing a five-year annualized total shareholder return of 14 percent, which ranks us 7th in the EEI index.

Given our confidence in the Company's future prospects, we also approved a third dividend increase in November, which was paid to shareholders of record in March 2006. Taken together, these actions raised the annual dividend from $1.50 to $1.80 per share – a 20-percent increase since November 2004.

In the important area of corporate governance, your Board remained focused on ensuring that we have the appropriate practices in place and that our Company maintains the highest ethical standards. Our corporate governance practices and policies continue to place us in the top quartile of the Corporate Governance Quotient developed by Institutional Shareholder Services.

On a personal note, I join the Board in expressing our appreciation to Robert N. Pokelwaldt, Paul J. Powers, and Dr. Patricia K. Woolf, whose terms as Directors will end with the 2006 Annual Meeting. We are indebted to them for their leadership and counsel during their combined 43 years of service to your Board and Company.

Also, we welcome back Robert B. "Yank" Heisler, Jr., who was elected to the Board in February. Yank is chairman of KeyBank N.A., chief executive officer of the McDonald Financial Group, and executive vice president of KeyCorp. He previously served on your Board between 1998 and 2004.

Thank you for your trust and confidence. Your Board will continue to work with management to ensure that your interests remain well-represented.

Sincerely,

George M. Smart

GEORGE M. SMART
Chairman of the Board

Paul T. Addison, 59
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, 54
President and Chief Executive Officer of FirstEnergy Corp. Director of FirstEnergy Corp. since 2002.

Dr. Carol A. Cartwright, 64
President, Kent State University. Chair, Corporate Governance Committee; Member, Compensation Committee. Director of FirstEnergy Corp. since 1997 and of Ohio Edison from 1992-1997.

William T. Cottle, 60
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., 57
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 February 2006.

Russell W. Maier, 69
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.

Paul T. Addison

Anthony J. Alexander

Dr. Carol A. Cartwright

William T. Cottle

Robert B. Heisler, Jr.

Russell W. Maier

Ernest J. Novak, Jr.

Robert N. Pokelwaldt

Paul J. Powers

Catherine A. Rein

Robert C. Savage

George M. Smart

Wes M. Taylor

Jesse T. Williams, Sr.

Dr. Patricia K. Woolf

Ernest J. Novak, Jr., 61
Retired, formerly Managing Partner of the Cleveland office of Ernst & Young LLP. Member, Audit and Finance Committees. Director of FirstEnergy Corp. since 2004.

Robert N. Pokelwaldt, 69
Retired, formerly Chairman of the Board and Chief Executive Officer of YORK International Corporation. Member, Audit and Finance Committees. Director of FirstEnergy Corp. since 2001 and of the former GPU, Inc., from 2000-2001.

Paul J. Powers, 71
Retired, formerly Chairman of the Board and Chief Executive Officer of Commercial Intertech Corp. Chair, Finance Committee, Member, Compensation Committee. Director of FirstEnergy Corp. since 1997 and of Ohio Edison from 1992-1997.

Catherine A. Rein, 63
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, 68
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, 60
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, 63
Retired, formerly President of TXU Generation. Member, Compensation and Nuclear Committees. Director of FirstEnergy Corp. since 2004.

Jesse T. Williams, Sr., 66
Retired, formerly Vice President of Human Resources Policy, Employment Practices and Systems of The Goodyear Tire & Rubber Company. Member, Corporate Governance and Nuclear Committees. Director of FirstEnergy Corp. since 1997 and of Ohio Edison from 1992-1997.

Dr. Patricia K. Woolf, 71
Consultant, author, and former Lecturer in the Department of Molecular Biology at Princeton University. Member, Corporate Governance and Nuclear Committees. Director of FirstEnergy Corp. since 2001 and of the former GPU, Inc., from 1983-2001.

FIRSTENERGY OFFICERS

FirstEnergy Corp.

Anthony J. Alexander
President and Chief Executive Officer

Richard R. Grigg
Executive Vice President and Chief Operating Officer

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

Leila L. Vespoli*
Senior Vice President and General Counsel

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

David W. Whitehead*
Corporate Secretary

James F. Pearson*
Treasurer

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

Charles E. Jones
Senior Vice President

David C. Luff
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

Terrance G. Howson
Vice President

Ali Jamshidi
Vice President

Mark A. Julian
Vice President

Thomas C. Navin
Vice President

Daniel V. Steen
Vice President

Stanley F. Szwed
Vice President

Bradford F. Tobin
Vice President and Chief Procurement Officer

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

Ronald E. Seeholzer
Assistant Controller

FirstEnergy Solutions Corp.

Guy L. Pipitone
President

Charles D. Lasky
Vice President

Alfred G. Roth
Vice President

Donald R. Schneider
Vice President

Arthur W. Yuan
Vice President

FirstEnergy Nuclear Operating Company

Anthony J. Alexander
Chief Executive Officer

Gary R. Leidich
President and Chief Nuclear Officer

Lew W. Myers
Executive Vice President

Joseph J. Hagan
Senior Vice President and Chief Operating Officer

Danny L. Pace
Senior Vice President, Engineering

Richard L. Anderson
Vice President, Nuclear Operations

Jeannie M. Rinckel
Vice President, Oversight

Mark B. Bezilla
Vice President, Davis-Besse

James H. Lash
Vice President, Beaver Valley

L. William Pearce
Vice President, Perry

FirstEnergy Regional Operations Management

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

Douglas S. Elliott
President, Pennsylvania Operations

Ronald P. Lantzy
Regional President, Metropolitan Edison Company

John E. Paganie
Regional President, Pennsylvania Electric Company

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.
CFC	Centerior Funding Corporation, a wholly owned finance subsidiary of CEI
Companies	OE, CEI, TE, Penn, JCP&L, Met-Ed and Penelec
EGSA	Empresa Guaracachi S.A.
Emdersa	Empresa Distribuidora Electrica Regional S.A.
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, the parent company of several heating, ventilation, air conditioning and energy management companies
GLEP	Great Lakes Energy Partners, LLC, an oil and natural gas exploration and production venture
GPU	GPU, Inc., former parent of JCP&L, Met-Ed and Penelec, which merged with FirstEnergy on November 7, 2001
GPU Capital	GPU Capital, Inc., owned and operated electric distribution systems in foreign countries
GPU Power	GPU Power, Inc., owned and operated generation facilities in foreign countries
JCP&L	Jersey Central Power & Light Company, a New Jersey electric utility operating subsidiary
JCP&L Transition	JCP&L Transition Funding LLC, a Delaware limited liability company and issuer of transition bonds
MARBEL	MARBEL Energy Corporation, previously held FirstEnergy's interest in GLEP
Met-Ed	Metropolitan Edison Company, a Pennsylvania electric utility operating subsidiary
MYR	MYR Group, Inc., a utility infrastructure construction service company
NEO	Northeast Ohio Natural Gas Corp., formerly a MARBEL subsidiary
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:

AEC	Alternative Energy Credit
ALJ	Administrative Law Judge
AOCL	Accumulated Other Comprehensive Loss
APB	Accounting Principles Board
APB 25	APB Opinion No. 25, "Accounting for Stock Issued to Employees"
APB 29	APB Opinion No. 29, "Accounting for Nonmonetary Transactions"
ARB	Accounting Research Bulletin
ARB 43	ARB No. 43, "Restatement and Revision of Accounting Research Bulletins"
ARO	Asset Retirement Obligation
BGS	Basic Generation Service
CAIR	Clean Air Interstate Rule
CAL	Confirmatory Action Letter
CAMR	Clean Air Mercury Rule
CAVR	Clean Air Visibility Rule
CAT	Commercial Activity Tax
CO_2	Carbon Dioxide
CTC	Competitive Transition Charge
DOJ	United States Department of Justice
DRA	Division of Ratepayer Advocate
ECAR	East Central Area Reliability Coordination Agreement
EITF	Emerging Issues Task Force
EITF 03-1	EITF Issue No. 03-1, "The Meaning of Other-Than-Temporary and Its Application to Certain Investments"
EITF 04-13	EITF Issue No. 04-13, "Accounting for Purchases and Sales of Inventory with the Same Counterparty"
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
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"
FMB	First Mortgage Bonds
FSP	FASB Staff Position
FSP 13-1	FASB Staff Position No. 13-1, "Accounting for Rental Costs Incurred during the Construction Period"
FSP 106-1	FASB Staff Position No.106-1, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003"
FSP 106-2	FASB Staff Position No.106-2, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003"
FSP 115-1 and FAS 124-1	FASB Staff Position No. 115-1 and FAS 124-1, "The Meaning of Other-Than Temporary Impairment and its Application to Certain Investments"
FSP 123(R)	FASB Staff Position No. 123(R), "Share-Based Payment"
GAAP	Accounting Principles Generally Accepted in the United States
GCAF	Generation Charge Adjustment Factor
GHG	Greenhouse Gases
HVAC	Heating, Ventilation and Air-conditioning
IRS	Internal Revenue Service
KWH	Kilowatt-hours
LOC	Letter of Credit
Medicare Act	Medicare Prescription Drug, Improvement and Modernization Act of 2003
MEIUG	Met-Ed Industrial Users Group
MISO	Midwest Independent System Transmission 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 Council
NJBPU	New Jersey Board of Public Utilities
NOAC	Northwest Ohio Aggregation Coalition
NOV	Notices of Violation
NO_X	Nitrogen Oxide
NRC	Nuclear Regulatory Commission
NUG	Non-Utility Generation
NUGC	Non-Utility Generation Clause
OCA	Office of Consumer Advocate
OCC	Office of the Ohio Consumers' Counsel
OCI	Other Comprehensive Income
OPAE	Ohio Partners for Affordable Energy
OPEB	Other Post-Employment Benefits
OSBA	Office of Small Business Advocate
OTS	Office of Trial Staff
PICA	Penelec Industrial Customer Association
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
S&P	Standard & Poor's Ratings Service
SBC	Societal Benefits Charge
SEC	U.S. Securities and Exchange Commission
SFAC	Statement of Financial Accounting Concepts
SFAC 7	SFAC No. 7, "Using Cash Flow Information and Present Value in Accounting Measurements"
SFAS	Statement of Financial Accounting Standards
SFAS 71	SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation"
SFAS 87	SFAS No. 87, "Employers' Accounting for Pensions"
SFAS 101	SFAS No. 101, "Accounting for Discontinuation of Application of SFAS 71"
SFAS 106	SFAS No. 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions"
SFAS 115	SFAS No. 115, "Accounting for Certain Investments in Debt and Equity Securities"
SFAS 123	SFAS No. 123, "Accounting for Stock-Based Compensation"
SFAS 123(R)	SFAS No. 123(R), "Share-Based Payment"
SFAS 131	SFAS No. 131, "Disclosures about Segments of an Enterprise and Related Information"
SFAS 133	SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities"
SFAS 140	SFAS No. 140, "Accounting for Transfers and Servicing of Financial Assets and Extinguishment of Liabilities"
SFAS 142	SFAS No. 142, "Goodwill and Other Intangible Assets"
SFAS 143	SFAS No. 143, "Accounting for Asset Retirement Obligations"
SFAS 144	SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets"
SFAS 150	SFAS No. 150, "Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity"
SFAS 151	SFAS No. 151, "Inventory Costs – an amendment of ARB No. 43, Chapter 4"
SFAS 153	SFAS No. 153, "Exchanges of Nonmonetary Assets – an amendment of APB Opinion No. 29"
SFAS 154	SFAS No. 154, "Accounting Changes and Error Corrections – a replacement of APB Opinion No. 20 and FASB Statement No. 3"
SO_2	Sulfur Dioxide
TBC	Transition Bond Charge
TMI-1	Three Mile Island Unit 1
TMI-2	Three Mile Island Unit 2
VIE	Variable Interest Entity

Management 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 2005 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 six 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 eight meetings in 2005.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rule 13a-15(f) of the Securities Exchange Act of 1934. Using the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in *Internal Control – Integrated Framework*, management conducted an evaluation of the effectiveness of the Company's internal control over financial reporting under the supervision of the chief executive officer and the chief financial officer. Based on that evaluation, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2005. Management's assessment of the effectiveness of the Company's internal control over financial reporting, as of December 31, 2005, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears on 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 2005 and 2004 consolidated financial statements and of its internal control over financial reporting as of December 31, 2005, and an audit of its 2003 consolidated financial statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Our opinions, based on our audits, are presented below.

CONSOLIDATED FINANCIAL STATEMENTS

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

As discussed in Note 2(K) and Note 12 to the consolidated financial statements, the Company changed its method of accounting for asset retirement obligations as of January 1, 2003 and conditional asset retirement obligations as of December 31, 2005. As discussed in Note 7 to the consolidated financial statements, the Company changed its method of accounting for the consolidation of variable interest entities as of December 31, 2003.

INTERNAL CONTROL OVER FINANCIAL REPORTING

Also, in our opinion, management's assessment, included in the accompanying Management's Report on Internal Control Over Financial Reporting, that the Company maintained effective internal control over financial reporting as of 2005 based on criteria established in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), is fairly stated, in all material respects, based on those criteria. Furthermore, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2005, based on criteria established in *Internal Control - Integrated Framework* issued by the COSO. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express opinions on management's assessment and on the effectiveness of the Company's internal control over financial reporting based on our audit. We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we consider necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

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

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

PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP
Cleveland, Ohio
February 27, 2006

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,	2005	2004	2003	2002	2001
Revenues(1)	$11,989	$12,060	$11,325	$11,169	$ 6,924
Income Before Discontinued Operations and Cumulative Effect of Accounting Changes	$ 873	$ 896	$ 444	$ 613	$ 648
Net Income	$ 861	$ 878	$ 423	$ 553	$ 646
Basic Earnings per Share of Common Stock:					
Before Discontinued Operations and Cumulative Effect of Accounting Changes	$ 2.66	$ 2.74	$ 1.46	$ 2.09	$ 2.82
After Discontinued Operations and Cumulative Effect of Accounting Changes	$ 2.62	$ 2.68	$ 1.39	$ 1.89	$ 2.82
Diluted Earnings per Share of Common Stock:					
Before Discontinued Operations and Cumulative Effect of Accounting Changes	$ 2.65	$ 2.73	$ 1.46	$ 2.08	$ 2.81
After Discontinued Operations and Cumulative Effect of Accounting Changes	$ 2.61	$ 2.67	$ 1.39	$ 1.88	$ 2.81
Dividends Declared per Share of Common Stock(2)	$1.705	$1.9125	$ 1.50	$ 1.50	$ 1.50
Total Assets	$31,841	$31,035	$32,878	$34,366	$37,334
Capitalization as of December 31:					
Common Stockholders' Equity	$ 9,188	$ 8,590	$ 8,290	$ 7,051	$ 7,399
Preferred Stock:					
Not Subject to Mandatory Redemption	184	335	335	335	480
Subject to Mandatory Redemption	–	–	–	428	595
Long-Term Debt and Other Long-Term Obligations	8,155	10,013	9,789	10,872	12,865
Total Capitalization	$17,527	$18,938	$18,414	$18,686	$21,339
Weighted Average Number of Basic Shares Outstanding	328	327	304	293	230
Weighted Average Number of Diluted Shares Outstanding	330	329	305	294	230

(1) The reduction of 2005 revenues compared to 2004 reflects a change in reporting methodology for PJM market transactions (see Note 2(D)) that had no impact on net income. Excluding that reporting change, revenues in 2005 were $997 million higher than 2004.

(2) 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 payable in 2006, increasing the indicated annual dividend rate from $1.72 to $1.80 per share. 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 declared in 2004 and paid March 1, 2005. Dividends declared in 2001, 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.

	2005		2004	
First Quarter High-Low	**$42.36**	**$37.70**	$39.37	$35.24
Second Quarter High-Low	**$48.96**	**$40.75**	$39.73	$36.73
Third Quarter High-Low	**$53.00**	**$47.46**	$42.23	$37.04
Fourth Quarter High-Low	**$53.36**	**$45.78**	$43.41	$38.35
Yearly High-Low	**$53.36**	**$37.70**	$43.41	$35.24

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

HOLDERS OF COMMON STOCK

There were 135,261 and 134,587 holders of 329,836,276 shares of FirstEnergy's Common Stock as of December 31, 2005 and January 31, 2006, 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), the repeal of PUHCA and the legal and regulatory changes resulting from the implementation of the EPACT, the uncertainty of the timing and amounts of the capital expenditures (including that such amounts could be higher than anticipated) or levels of emission reductions related to the settlement agreement 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 United States Attorney's Office, the Nuclear Regulatory Commission and the various state public utility commissions as disclosed in our Securities and Exchange Commission filings, generally, and with respect to the Davis-Besse Nuclear Power Station outage and heightened scrutiny at the Perry Nuclear Power Plant in particular, the continuing availability and operation of generating units, the ability of our generating units to continue to operate at, or near full capacity, our inability to accomplish or realize anticipated benefits from strategic goals (including employee workforce factors), the anticipated benefits from our voluntary pension plan contributions, our ability to improve electric commodity margins and to experience growth in the distribution business, our ability to access the public securities and other capital markets 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, circumstances which may lead management to seek, or the Board of Directors to grant, in each case in its sole discretion, authority for the implementation of a share repurchase program in the future, the risks and other factors discussed from time to time in our Securities and Exchange Commission filings, and other similar factors. Dividends declared from time to time during any annual period may in aggregate vary from the indicated amounts due to circumstances considered by the Board at the time of the actual declarations. Also, a credit rating should not be viewed as a recommendation to buy, sell or hold securities and may be revised or withdrawn by a rating agency at any time. 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

Earnings before unusual items on a Non-GAAP basis in 2005 were $984 million, or basic earnings before unusual items of $3.00 per share of common stock, compared to $991 million (basic earnings of $3.03 per share) in 2004 and $736 million (basic earnings of $2.42 per share) in 2003. On a GAAP basis, net income was $861 million, or basic earnings of $2.62 per share of common stock in 2005 compared to $878 million (basic earnings of $2.68 per share) in 2004 and $423 million (basic earnings of $1.39 per share) in 2003. The following Non-GAAP Reconciliation displays the unusual items resulting in the difference between GAAP and Non-GAAP earnings:

Non-GAAP Reconciliation

	2005		2004		2003	
	After-tax Amount	Basic Earnings Per Share	After-tax Amount	Basic Earnings Per Share	After-tax Amount	Basic Earnings Per Share
	(In millions, except per share amounts)					
Earnings Before Unusual Items (Non-GAAP)	$984	$3.00	$991	$3.03	$736	$2.42
Cumulative effect of accounting changes	(30)	(0.09)			102	0.33
Ohio/New Jersey income tax adjustments	(63)	(0.19)				
EPA settlement	(14)	(0.04)				
Davis-Besse DOJ penalty and NRC fines	(31)	(0.10)				
JCP&L arbitration decision	(10)	(0.03)				
JCP&L rate settlement	16	0.05				
Non-core asset sales/ impairments	9	0.02	(60)	(0.19)	(125)	(0.41)
Davis-Besse extended outage impacts			(38)	(0.12)	(170)	(0.56)
Class-action lawsuit settlement			(11)	(0.03)		
JCP&L disallowance					(109)	(0.36)
NRG settlement					99	0.33
Discontinued international operations					(101)	(0.33)
Other			(4)	(0.01)	(9)	(0.03)
Net Income (GAAP)	$861	$2.62	$878	$2.68	$423	$1.39

The Non-GAAP measure above, earnings before unusual items, is not calculated in accordance with GAAP because it excludes the impact of "unusual items." Unusual items reflect the impact on earnings of events that are not routine or for which we believe the financial impact will disappear or become immaterial within a near-term finite period. By removing the earnings effect of such issues that have been resolved or are expected to be resolved over the near term, our management and investors can better measure our business and earnings potential. In particular, the non-core asset sales item refers to a finite set of energy-related assets that had been previously disclosed as held for sale, a substantial portion of which has already been sold. In addition, as Davis-Besse restarted in 2004, further impacts from its extended outage are not expected. Similarly, the DOJ penalty and NRC fines in 2005 and further litigation settlements similar to the class action settlements in 2004 are not reasonably expected over the near term. Furthermore, we believe presenting normalized earnings calculated in this manner provides useful information to investors in evaluating the ongoing results of our businesses over the longer term and assists investors in comparing our operating performance to the operating performance of others in the energy sector.

Sales and Production - KWH sales for 2005 were higher than the previous year, driven primarily by strong sales to residential and commercial customers. An unseasonably warmer summer and a colder fourth quarter in 2005 led to our generating fleet producing a record 80.2 billion KWH, compared to 76.4 billion KWH in 2004. Our non-nuclear fleet produced record output of 51.5 billion KWH and our nuclear fleet produced 28.7 billion KWH.

Davis-Besse Issues - In January 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 DOJ will 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 remains in compliance with the agreement.

FENOC agreed to pay a penalty of $28 million (which is not deductible for income tax purposes) that reduced our earnings per share of common stock by $0.09 in 2005. As part of the deferred prosecution agreement entered into with the DOJ, $4.35 million of that amount was directed to community service projects. In entering into this 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 all 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.

Pension Contribution - In December 2005, we made a voluntary $500 million contribution to our pension plan. The impact of the pension contribution is expected to be accretive to earnings and further increase security of future plan benefits. Since the contribution is deductible for tax purposes, the after-tax cash impact was approximately $341 million in 2005. We funded this payment through available short-term credit facilities and anticipate repaying such borrowings during 2006 through positive cash flow.

New Jersey Rate Matters - JCP&L filed a request in December 2005 with the NJBPU for an increase in its NUGC, totaling $165 million, or approximately $4.08 per month for a residential customer using 500 KWH of electricity. The proposed 6.4% increase in JCP&L's total revenues is designed to recover above-market costs associated with mandated long-term contracts between JCP&L and various NUGs. Above-market NUG costs are deferred on our balance sheet as a regulatory asset. Revenues collected through the NUGC reduce the regulatory asset and, therefore, the $165 million annual increase will not have an effect on net income due to deferral accounting.

Ohio Rate Matters - On September 9, 2005, the Ohio Companies filed an application with the PUCO that supplemented their existing RSP with an RCP designed to provide customers with more certain rate levels than otherwise available under the RSP during the plan period. On January 4, 2006, the PUCO approved the RCP filing with modifications. On January 10, 2006, the Ohio Companies filed a Motion for Clarification of the PUCO order approving the RCP. 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 related issues.

S&P Ratings Upgrade - In October 2005, S&P raised its corporate credit rating of FirstEnergy and the Companies to 'BBB' from 'BBB-'. At the same time, S&P raised our senior unsecured ratings at the holding company to 'BBB-' from 'BB+' and each of the Companies by one notch above previous ratings. S&P noted that the upgrade followed the continuation of a good operating track record, specifically for the nuclear fleet through the third quarter of 2005. S&P also stated that our rating reflects the benefits of supportive regulation, our low-cost base load generation fleet, low-risk transmission and distribution operations and rate certainty in Ohio. Our ability to consistently generate free cash flow, good liquidity and an improving financial profile were noted as strengths.

New Source Review Settlement - In March 2005, we reached a settlement with the EPA, the DOJ, and the States of Connecticut, New Jersey and New York that resolved all issues related to various parties' actions against our W. H. Sammis Plant in the pending New Source Review case. Under the agreement, which is in the form of a consent decree of the U.S. District Court, we will install environmental controls at the Sammis Plant, as well as some of our other power plants. We will also upgrade existing scrubber systems on Units 1, 2 and 3 of our Bruce Mansfield Plant. Projects at the Sammis Plant will include equipment designed to reduce 95% of SO_2 emissions and 90% of NOx emissions on the plant's two largest units. Additionally, the plant's five smaller units will be fitted with control equipment designed to reduce at least 50% of SO_2 and 70% of NOx emissions. In total, additional environmental controls are expected to be installed on nearly 5,500 MW of our 7,400 MW coal-fired generating capacity. Construction began in 2005 and is expected to be completed by 2012.

The estimated $1.5 billion investment in environmental improvements agreed to under the settlement agreement is consistent with assumptions reflected in our long-term financial planning prior to settlement. Nearly all of the expenditures are expected to be capital additions and depreciated over a period of years. Additionally, we paid an $8.5 million civil penalty to the DOJ and will contribute up to $25 million over five years to support environmentally beneficial projects as part of the settlement terms. This settlement penalty reduced our earnings per share of common stock by $0.03 in the second quarter of 2005.

Dividends - The Board of Directors increased our quarterly dividend twice during 2005, representing a 9.1% increase over the rate in effect at the beginning of the year. The first increase of 1.75 cents per share (a 4.2% increase) was declared on September 20. The second increase of 2 cents per share (a 4.7% increase) was declared on November 15 and is payable March 1, 2006. As of December 31, 2005, our quarterly dividend rate stood at $0.45 per share of common stock – an annual indicated dividend rate of $1.80 per share. The amount and timing of all dividend declarations are subject to the discretion of the Board of Directors and its consideration of business conditions, results of operations, financial condition and other factors.

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 – Business Segments).

- **Regulated Services** transmits and distributes electricity through our eight utility operating companies that collectively comprise the nation's fifth largest investor-owned electric system, 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 our Power Supply Management Services segment in the states in which our utility subsidiaries operate. The service areas of our utilities are summarized below:

Company	Area Served	Customers Served
OE	Central and Northeastern Ohio	1,038,000
Penn	Western Pennsylvania	158,000
CEI	Northeastern Ohio	763,000
TE	Northwestern Ohio	314,000
JCP&L	Northern, Western and East Central New Jersey	1,072,000
Met-Ed	Eastern Pennsylvania	534,000
Penelec	Western Pennsylvania	588,000
ATSI	Service areas of OE, Penn, CEI and TE	

- **Power Supply Management Services** supplies all of the electric power needs of our end-use customers through retail and wholesale arrangements, including regulated retail sales to meet the PLR requirements of our Ohio and Pennsylvania companies and competitive retail sales to commercial and industrial businesses primarily in Ohio, Pennsylvania and Michigan. This business segment owns and operates our generating facilities and purchases electricity from the wholesale market to meet our sales obligations (See FirstEnergy Intra-System Generation Asset Transfers below). 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 provide a wide range of services, including heating, ventilation, air-conditioning, refrigeration, electrical and facility control systems, high-efficiency electrotechnologies and telecommunication services, and previously included international operations that were divested in January 2004. We are in the process of divesting our remaining 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".

We acquired international assets in our merger with GPU in November 2001. GPU Capital and its subsidiaries provided electric distribution services in foreign countries (see Results of Operations – Discontinued Operations). GPU Power and its subsidiaries also owned and operated generation facilities in foreign countries. As of January 30, 2004, all of our international operations had been divested because those operations were not aligned with our strategy.

STRATEGY

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

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

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 could adversely affect our profit margins;
- Nuclear generation involves risks that include uncertainties relating to health and safety, additional capital costs, the adequacy of insurance coverage and nuclear plant decommissioning;
- Regulatory changes in the electric industry could affect our competitive position and result in unrecoverable costs adversely affecting our business and results of operations;
- 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;
- Complex and changing government regulations could have a negative impact on our results of operations;
- Costs of compliance with environmental laws are significant, and the cost of compliance with future environmental laws could adversely affect cash flow and profitability;

- There are uncertainties relating to our participation in the PJM and MISO Regional Transmission Organizations;
- Weather conditions such as tornadoes, hurricanes, ice storms and droughts, as well as seasonal temperature variations could have a negative impact on our results of operations;
- We are subject to financial performance risks related to the economic cycles of the electric utility industry;
- 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 face certain human resource risks associated with the availability of trained and qualified labor to meet our future staffing requirements;
- 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;
- 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;
- We may ultimately incur liability in connection with federal proceedings; and
- Acts of war or terrorism could negatively impact our business.

FIRSTENERGY INTRA-SYSTEM GENERATION ASSET TRANSFERS

On May 13, 2005, Penn, and on May 18, 2005, our Ohio Companies 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. 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 intercompany 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 2005 that have been classified as discontinued operations (see Note 2(J)). These reclassifications did not change previously reported earnings for 2004 and 2003.

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 FSG business segment is included in "Other and Reconciling Adjustments" due to its immaterial impact on current period financial results, but is presented separately in segment information provided in Note 16 to the consolidated financial statements. Net income (loss) by major business segment was as follows:

				Increase (Decrease)	
	2005	2004	2003	2005 vs 2004	2004 vs 2003
	(In millions, except per share amounts)				
Net Income (Loss) By Business Segment:					
Regulated services	$1,046	$1,015	$1,164	$ 31	$(149)
Power supply management services	14	104	(320)	(90)	424
Other and reconciling adjustments*	(199)	(241)	(421)	42	180
Total	$ 861	$ 878	$ 423	$ (17)	$ 455
Basic Earnings Per Share:					
Income before discontinued operations and cumulative effect of accounting changes	$ 2.66	$ 2.74	$ 1.46	$(0.08)	$1.28
Discontinued operations	0.05	(0.06)	(0.40)	0.11	0.34
Cumulative effect of accounting changes	(0.09)	–	0.33	(0.09)	(0.33)
Basic earnings per share	$ 2.62	$ 2.68	$ 1.39	$(0.06)	$1.29
Diluted Earnings Per Share:					
Income before discontinued operations and cumulative effect of accounting changes	$ 2.65	$ 2.73	$ 1.46	$(0.08)	$1.27
Discontinued operations	0.05	(0.06)	(0.40)	0.11	0.34
Cumulative effect of accounting changes	(0.09)	–	0.33	(0.09)	(0.33)
Diluted earnings per share	$ 2.61	$ 2.67	$ 1.39	$(0.06)	$1.28

** 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 new Ohio tax legislation.*

Summary of Results of Operations – 2005 Compared with 2004

Financial results for our reportable major business segments in 2005 and 2004 were as follows:

2005 Financial Results	Regulated Services	Power Supply Management Services	Other and Reconciling Adjustments	FirstEnergy Consolidated
		(In millions)		
Revenues:				
External				
Electric	$4,915	$5,631	$ –	$10,546
Other	568	108	767	1,443
Internal	270	–	(270)	–
Total Revenues	5,753	5,739	497	11,989
Expenses:				
Fuel and Purchased power	–	4,011	–	4,011
Other operating expenses	1,757	1,479	489	3,725
Provision for depreciation	516	45	28	589
Amortization of regulatory assets	1,281	–	–	1,281
Deferral of new regulatory assets	(405)	–	–	(405)
Goodwill impairment	–	–	9	9
General taxes	602	91	20	713
Total Expenses	3,751	5,626	546	9,923
Operating Income (Loss)	2,002	113	(49)	2,066
Other Income (Expense):				
Investment income	218	–	–	218
Interest expense	(393)	(55)	(213)	(661)
Capitalized interest	18	1	–	19
Subsidiaries' preferred stock dividends	(15)	–	–	(15)
Total Other Income (Expense)	(172)	(54)	(213)	(439)
Income taxes (benefit)	763	36	(45)	754
Income before discontinued operations and cumulative effect of accounting change	1,067	23	(217)	873
Discontinued operations	–	–	18	18
Cumulative effect of accounting change	(21)	(9)	–	(30)
Net Income (Loss)	$1,046	$ 14	$(199)	$ 861

2004 Financial Results	Regulated Services	Power Supply Management Services	Other and Reconciling Adjustments	FirstEnergy Consolidated
		(In millions)		
Revenues:				
External				
Electric	$4,701	$6,130	$ –	$10,831
Other	490	74	665	1,229
Internal	318	–	(318)	–
Total Revenues	5,509	6,204	347	12,060
Expenses:				
Fuel and purchased power	–	4,469	–	4,469
Other operating expenses	1,602	1,402	370	3,374
Provision for depreciation	513	35	39	587
Amortization of regulatory assets	1,166	–	–	1,166
Deferral of new regulatory assets	(257)	–	–	(257)
Goodwill impairment	–	–	12	12
General taxes	572	85	21	678
Total Expenses	3,596	5,991	442	10,029
Operating Income (Loss)	1,913	213	(95)	2,031
Other Income (Expense):				
Investment income	205	–	–	205
Interest expense	(361)	(43)	(267)	(671)
Capitalized interest	19	6	–	25
Subsidiaries' preferred stock dividends	(21)	–	–	(21)
Total Other Income (Expense)	(158)	(37)	(267)	(462)
Income taxes (benefit)	740	72	(139)	673
Income before discontinued operations and cumulative effect of accounting change	1,015	104	(223)	896
Discontinued operations	–	–	(18)	(18)
Cumulative effect of accounting change	–	–	–	–
Net Income (Loss)	$1,015	$ 104	$(241)	$ 878

Change Between 2005 and 2004 Financial Results	Regulated Services	Power Supply Management Services	Other and Reconciling Adjustments[1]	FirstEnergy Consolidated
Increase (Decrease)		(In millions)		
Revenues:				
External				
Electric	$214	$(499)	$ –	$(285)
Other	78	34	102	214
Internal	(48)	–	48	–
Total Revenues	244	(465)	150	(71)
Expenses:				
Fuel and purchased power	–	(458)	–	(458)
Other operating expenses	155	77	119	351
Provision for depreciation	3	10	(11)	2
Amortization of regulatory assets	115	–	–	115
Deferral of new regulatory assets	(148)	–	–	(148)
Goodwill impairment	–	–	(3)	(3)
General taxes	30	6	(1)	35
Total Expenses	155	(365)	104	(106)
Operating Income	89	(100)	46	35
Other Income (Expense):				
Investment income	13	–	–	13
Interest expense	(32)	(12)	54	10
Capitalized interest	(1)	(5)	–	(6)
Subsidiaries' preferred stock dividends	6	–	–	6
Total Other Income (Expense)	(14)	(17)	54	23
Income taxes	23	(36)	94	81
Income before discontinued operations and cumulative effect of accounting change	52	(81)	6	(23)
Discontinued operations	–	–	36	36
Cumulative effect of accounting change	(21)	(9)	–	(30)
Net Income	$ 31	$ (90)	$42	$ (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 $31 million to $1.05 billion, a 3.1% increase in 2005, compared to $1.02 billion in 2004, primarily as a result of increased sales to customers.

Revenues –

Total revenues increased by $244 million in 2005 compared to 2004, resulting from the following sources:

Revenues by Type of Service	2005	2004	Increase (Decrease)
		(In millions)	
Distribution services	$4,915	$4,701	$214
Transmission services	415	333	82
Lease revenue from affiliates	270	318	(48)
Other	153	157	(4)
Total Revenues	$5,753	$5,509	$244

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 $214 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	(54)
Net Increase in Distribution Revenues	$214

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 increased by $155 million in 2005 compared to the prior year due to the following:

- Other operating expenses increased by $155 million in 2005 compared to 2004 primarily due to higher transmission expenses resulting in part from increased loads and higher transmission system usage charges;
- Additional amortization of regulatory assets of $115 million, principally Ohio transition costs, which was due primarily to using the interest method to amortize regulatory assets; and
- General taxes increased by $30 million due to higher property taxes and increased KWH deliveries which increased the Ohio KWH tax and the Pennsylvania gross receipts tax.

Partially offsetting these higher costs were additional deferrals of regulatory assets of $148 million, primarily due to the PUCO-approved deferral of MISO administrative costs, shopping incentive credits and related interest on those deferrals.

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 $13 million in 2005 due primarily to realized gains on nuclear decommissioning trust investments.
- Interest expense was $32 million higher in 2005.

Power Supply Management Services – 2005 Compared with 2004

Net income for this segment decreased $90 million resulting in net income of $14 million for 2005 compared to net income of $104 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 our 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 $26 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	65	39	26
Other	43	35	8
Total	5,739	5,136	603
PJM adjustment	–	1,068	(1,068)
Total Revenues	$5,739	$6,204	$ (465)

[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:

Source 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 $703 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:

Source 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 $77 million in 2005 compared to 2004. Non-fuel nuclear costs were higher in 2005 due to refueling outages at Perry Unit 1 (including an unplanned extension) and Beaver Valley Unit 2 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 due primarily to increased loads and higher transmission system usage charges further increased other operating costs in 2005. The higher costs this year 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.

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 $42 million increase in net income compared to 2004. The increase was partially due to the absence this year of goodwill impairments at FSG of $25 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 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 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 have been 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 include 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 the new standard 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 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 for the year ended December 31, 2005. (See Note 12.)

Summary of Results of Operations – 2004 compared with 2003

Financial results for our major business segments for 2004 and 2003 were as follows:

2004 Financial Results	Regulated Services	Power Supply Management Services	Other and Reconciling Adjustments	FirstEnergy Consolidated
		(In millions)		
Revenues:				
External				
Electric	$4,701	$6,130	$ –	$10,831
Other	490	74	665	1,229
Internal	318	–	(318)	–
Total Revenues	5,509	6,204	347	12,060
Expenses:				
Fuel and purchased power	–	4,469	–	4,469
Other operating	1,602	1,402	370	3,374
Provision for depreciation	513	35	39	587
Amortization of regulatory assets	1,166	–	–	1,166
Deferral of new regulatory assets	(257)	–	–	(257)
Goodwill impairment	–	–	12	12
General taxes	572	85	21	678
Total Expenses	3,596	5,991	442	10,029
Operating Income (Loss)	1,913	213	(95)	2,031
Other Income (Expense):				
Investment income	205	–	–	205
Interest expense	(361)	(43)	(267)	(671)
Capitalized interest	19	6	–	25
Subsidiaries' preferred stock dividends	(21)	–	–	(21)
Total Other Income (Expense)	(158)	(37)	(267)	(462)
Income taxes (benefit)	740	72	(139)	673
Income before discontinued operations and cumulative effect of accounting change	1,015	104	(223)	896
Discontinued operations	–	–	(18)	(18)
Cumulative effect of accounting change	–	–	–	–
Net Income (Loss)	$1,015	$ 104	$(241)	$ 878

2003 Financial Results	Regulated Services	Power Supply Management Services	Other and Reconciling Adjustments	FirstEnergy Consolidated
		(In millions)		
Revenues:				
External				
Electric	$4,787	$5,418	$ –	$10,205
Other	281	69	770	1,120
Internal	319	–	(319)	–
Total Revenues	5,387	5,487	451	11,325
Expenses:				
Fuel and purchased power	–	4,159	–	4,159
Other operating	1,442	1,723	475	3,640
Claim settlement	(168)	–	–	(168)
Provision for depreciation	538	29	37	604
Amortization of regulatory assets	1,079	–	–	1,079
Deferral of new regulatory assets	(194)	–	–	(194)
Goodwill impairment	–	–	91	91
General taxes	540	74	24	638
Total Expenses	3,237	5,985	627	9,849
Operating Income (Loss)	2,150	(498)	(176)	1,476
Other Income (Expense):				
Investment income	185	–	–	185
Interest expense	(473)	(51)	(275)	(799)
Capitalized interest	22	7	3	32
Subsidiaries' preferred stock dividends	(42)	–	–	(42)
Total Other Income (Expense)	(308)	(44)	(272)	(624)
Income taxes (benefit)	779	(222)	(149)	408
Income before discontinued operations and cumulative effect of accounting change	1,063	(320)	(299)	444
Discontinued operations	–	–	(123)	(123)
Cumulative effect of accounting change	101	–	1	102
Net Income (Loss)	$1,164	$ (320)	$(421)	$ 423

Change Between 2004 and 2003 Financial Results	Regulated Services	Power Supply Management Services	Other and Reconciling Adjustments	FirstEnergy Consolidated
Increase (Decrease)		*(In millions)*		
Revenues:				
External				
Electric	$ (86)	$712	$ –	$626
Other	209	5	(105)	109
Internal	(1)	–	1	–
Total Revenues	122	717	(104)	735
Expenses:				
Fuel and purchased power	–	310	–	310
Other operating	160	(321)	(105)	(266)
Claim settlement	168	–	–	168
Provision for depreciation	(25)	6	2	(17)
Amortization of regulatory assets	87	–	–	87
Deferral of new regulatory assets	(63)	–	–	(63)
Goodwill impairment	–	–	(79)	(79)
General taxes	32	11	(3)	40
Total Expenses	359	6	(185)	180
Operating Income	(237)	711	81	555
Other Income (Expense):				
Investment income	20	–	–	20
Interest expense	112	8	8	128
Capitalized interest	(3)	(1)	(3)	(7)
Subsidiaries' preferred stock dividends	21	–	–	21
Total Other Income (Expense)	150	7	5	162
Income taxes (benefit)	(39)	294	10	265
Income before discontinued operations and cumulative effect of accounting change	(48)	424	76	452
Discontinued operations	–	–	105	105
Cumulative effect of accounting change	(101)	–	(1)	(102)
Net Income	$(149)	$424	$180	$455

Regulated Services – 2004 Compared with 2003

Net income decreased $149 million to $1.02 billion in 2004, from $1.16 billion in 2003. Income before discontinued operations and the cumulative effect of an accounting change decreased $48 million reflecting the absence in 2004 of the earnings benefit of the 2003 settlement of our claim against NRG for the terminated sale of four fossil plants (which resulted in a $168 million gain), partially offset by lower interest charges during 2004 due to debt and preferred stock redemption and refinancing activities.

Revenues –

Total revenues increased by $122 million in 2004 compared to 2003, resulting from the following sources:

Revenues by Type of Service	2004	2003	Increase (Decrease)
		(In millions)	
Distribution services	$4,701	$4,787	$ (86)
Transmission services	333	76	257
Lease revenue from affiliates	318	319	(1)
Other	157	205	(48)
Total Revenues	$5,509	$5,387	$122

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

Electric Distribution Deliveries	
Residential	2.0%
Commercial	2.6
Industrial	0.6
Total Distribution Deliveries	1.6%

Lower prices partially offset by higher customer consumption and increased shopping incentive deferrals resulted in lower distribution delivery revenues. The following table summarizes major factors contributing to the $86 million decrease in distribution services revenue in 2004:

Sources of Change in Distribution Revenues	Increase (Decrease)
	(In millions)
Changes in customer usage	$ 82
Changes in prices:	
Rate changes -	
Ohio shopping credit incentives	(53)
JCP&L rate increase	17
Billing component reallocations	(132)
Net Decrease in Distribution Revenues	$(86)

Lower prices resulted from higher customer shopping credit incentives, partially offset by higher base rates at JCP&L. Energy demand increased in all three retail customer groups, but the milder weather in 2004 moderated the energy needs of residential and commercial customers. The increased shopping incentives provided to customers under the Ohio transition plan are deferred for future recovery and do not affect current period earnings.

Transmission revenues increased by $257 million in 2004 compared to 2003 due in part to the June 2004 amendments to power supply agreements with FES where Met-Ed and Penelec assumed certain transmission activity from FES and the fact that 2004 revenues reflected transactions with MISO, which began operations in December 2003.

Expenses –

Total operating expenses increased by $359 million in 2004 compared to 2003 due to the following:

- Other operating expenses increased $160 million due to higher transmission expenses of $238 million related to the assumption of additional transmission activity from FES discussed above. These higher costs were partially offset by lower energy delivery expenses due to reduced storm restoration costs in 2004, a higher level of construction activities in 2004 compared to a higher level of maintenance activities in the prior year and distribution reliability expenses incurred in the third quarter of 2003;
- Additional amortization of regulatory assets of $87 million, principally from higher Ohio transition plan amortization and a change in amortization resulting from the July 2003 JCP&L rate decision;
- An aggregate increase in Ohio property tax expense and other state taxes of $32 million; and
- The absence in 2004 of the $168 million claim settlement of our claim against NRG discussed above.

Partially offsetting these higher costs were additional deferrals of regulatory assets of $63 million, due principally to Ohio shopping incentives, and lower depreciation expense of $25 million principally due to the reduced depreciation rates effective in August 2003 in connection with the JCP&L rate case decision. The $48 million decrease in other revenue reflects lower revenues from accounts receivable financing, JCP&L transition bond securitization and utility property rentals.

Other Income –

Total other income (expense) increased by $150 million in 2004 compared to 2003 due to the following:

- Investment income increased approximately $20 million in 2004 due primarily to higher realized gains on nuclear decommissioning trust investments.
- Lower interest charges of $130 million resulted from debt and preferred stock redemptions and refinancing activities and pollution control note repricings.

Power Supply Management Services – 2004 Compared with 2003

Net income for this segment increased by $424 million to $104 million in 2004 compared to a net loss of $320 million in 2003. An improved gross generation margin and lower nuclear and fossil operating costs contributed to this increase.

Revenues –

The change in reported segment revenues resulted from the following:

Revenues by Type of Service	2004	2003	Increase (Decrease)
		(In millions)	
Electric generation sales:			
Retail	$3,795	$3,705	$ 90
Wholesale	2,335	1,713	622
Total electric generation sales	6,130	5,418	712
Transmission	39	59	(20)
Other	35	10	25
Total Revenues	$6,204	$5,487	$717

The higher wholesale revenues were due to higher unit prices and increased generation available for the wholesale market which was possible due in part to a 13% increase in available generation resulting from record production from our generation fleet. Increased retail sales reflected the effect of higher unit prices. The following table summarizes the price and volume factors contributing to the increased revenues from retail and wholesale customers.

Source of Change in Electric Generation Sales	Increase (Decrease)
	(In millions)
Retail:	
Effect of 0.6% decrease in customer usage	$ (22)
Change in prices	112
	90
Wholesale:	
Effect of 26.7% increase in customer usage	492
Change in prices	130
	622
Net Increase in Electric Generation Sales	$712

The $20 million decrease in transmission revenues relates to lower PJM network transmission system revenue, reduced financial transmission rights (FTR)/auction revenue rights (ARR), and PJM congestion credit revenues related to transmission transactions that Met-Ed and Penelec assumed in June 2004 due to their amended power supply agreement with FES.

Expenses -

Total operating expenses increased by $6 million in 2004 compared to 2003. Higher costs for fuel and purchased power, depreciation and general taxes were almost entirely offset by lower other operating costs. Fuel and purchased power costs increased $310 million, resulting from higher fuel costs of $46 million and increased purchased power costs of $264 million. Factors contributing to the higher costs are summarized in the following table:

Source of Change in Fuel and Purchased Power	Increase (Decrease)
	(In millions)
Fuel:	
Change due to unit costs	$ (43)
Change due to volume consumed	89
	46
Purchased Power:	
Change due to unit costs	297
Change due to volume purchased	153
Increase in deferred costs	(33)
	417
2003 JCP&L disallowed purchased power costs	(153)
Net Increase in Fuel and Purchased Power Costs	$310

Fuel costs increased primarily from higher nuclear generation in 2004. Excluding the unusual charge resulting from the July 2003 JCP&L rate decision, purchased power costs increased by $417 million.

Other operating costs decreased $321 million in 2004 compared to 2003. This decrease principally resulted from lower non-fuel nuclear and fossil generation costs. Nuclear operating costs decreased by $169 million resulting from one scheduled refueling outage at Beaver Valley Unit 1 in 2004 compared to three scheduled refueling outages in 2003 (Beaver Valley Unit 1, Beaver Valley Unit 2 and Perry) and reduced incremental maintenance costs at the Davis-Besse Plant related to its restart. Fossil generation expense was $49 million lower primarily due to reduced maintenance outages in 2004 compared to the prior year. Lower transmission costs, due to the power supply agreement amendments discussed above, and reduced employee benefit expenses (see POSTRETIREMENT PLANS) also contributed to the remaining $103 million decrease in other operating costs.

Other – 2004 Compared with 2003

FirstEnergy's financial results from other operating segments and reconciling adjustments included interest expense on holding company debt, corporate support services revenues and expenses, FSG results and results from international businesses acquired in the 2001 merger. As of January 30, 2004, all of the international operations were divested. The absence of the EGSA sale loss of $33 million and the Emdersa abandonment charge of $67 million included in the 2003 discontinued operations losses was a primary cause of the $180 million increase in net income in 2004 compared to 2003. In addition, an $86 million decrease in FSG goodwill impairment charges in 2004 compared to 2003 (see Note 2(H)) was the other primary factor in the net income increase.

CUMULATIVE EFFECT OF ACCOUNTING CHANGE

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

DISCONTINUED OPERATIONS

Discontinued operations for 2005 include the divestiture of two FSG subsidiaries: Elliott-Lewis Corporation and L. H. Cranston and Sons, Inc.; the divestiture of an MYR subsidiary - Power Piping Company; and the sale of FES' natural gas business. The operating results for these divested businesses were adjusted in the presentation for prior years.

In 2003, the results of certain FSG subsidiaries (Colonial Mechanical, Webb Technologies and Ancoma, Inc.) and MARBEL's subsidiary, which were divested in 2003, were reported as discontinued operations. In addition, 2003 discontinued operations were reflected for Emdersa and EGSA, as we substantially completed our exit from foreign operations acquired through the merger with GPU in 2001.

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

Discontinued Operations (Net of tax)	2005	2004	2003
		(In millions)	
Emdersa - abandonment	$ –	$ –	$ (67)
EGSA - loss on sale	–	–	(33)
FES natural gas business – gain on sale	5	–	–
FSG and MYR subsidiaries – gain (loss) on sale	12	–	(3)
Total gain (loss) on divestitures	17	–	(103)
Reclassification of operating income (loss) to discontinued operations:			
FES natural gas business	–	4	(2)
FSG and MYR subsidiaries	1	(22)	(22)
Emdersa, EGSA and NEO	–	–	4
Income (loss) from discontinued operations	$18	$(18)	$(123)

POSTRETIREMENT PLANS

Strengthened equity markets, as well as a $500 million voluntary cash pension contribution made in September 2004, contributed to a $66 million reduction of postretirement benefits expenses in 2005 from the prior year. Improved equity markets and amendments to our health care benefits plan in the first quarter of 2004 and the Medicare Act signed by President Bush in December 2003 combined to reduce postretirement benefits expenses by $109 million in 2004 from the prior year. The following table reflects the portion of postretirement costs that were charged to expense in 2005, 2004 and 2003:

Postretirement Expenses	2005	2004	2003
		(In millions)	
Pension	$ 32	$ 83	$123
OPEB	72	87	156
Total	$104	$170	$279

Pension and OPEB expenses are included in various cost categories and have contributed to cost decreases discussed above for 2005. We made an additional $500 million voluntary contribution to our pension plan in the fourth quarter of 2005 that is expected to result in reduced pension costs in 2006 and 2007 compared to costs that would have otherwise resulted without the voluntary contribution. In 2008, we will increase retirees' share of their coinsurance, as well as increase retirees' health care premiums, which will reduce OPEB costs in 2006 and 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 affiliates are obligated to provide generation service with an estimated power demand of 101.2 billion KWH for 2006. 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 65% of the total generation service obligation is for customers located in the MISO market area and 35% for customers located in the PJM market area. Included in the PJM market area are obligations of FES to provide power to electric distribution customers in the State of New Jersey, including customers in JCP&L's service territory. FES incurred this obligation as a successful bidder in the State of New Jersey's auction of BGS.

Within the franchise territories of our utilities, alternative energy suppliers currently provide generation service for approximately 100 MW (summer peak) of load with an estimated energy requirement of 0.8 billion KWH. If these alternate suppliers fail to deliver power to their customers located in the utility's service area, the utility must procure replacement power in the role of PLR (see Note 10 for 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 affiliates own and operate 13,427 MW of installed generating capacity, which for 2006 is expected to provide approximately 80% 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 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 cash requirements in 2005 for operating expenses, construction expenditures, scheduled debt maturities and preferred stock redemptions were met without increasing our net debt and preferred stock outstanding. During 2006, we expect to meet our contractual obligations primarily with cash from operations. Borrowing capacity under credit facilities is available to manage working capital requirements. In subsequent years, we expect to use a combination of cash from operations and funds from the capital markets.

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 $2.0 billion of short-term financing under a revolving credit facility which expires in 2010, subject to short-term debt limitations under current regulatory approvals of $1.5 billion and to outstanding borrowings by subsidiaries of FirstEnergy that are also parties to such facility. In 2005, we received $1.3 billion of cash dividends from our subsidiaries and paid $546 million in cash dividends to our common shareholders. There are no material restrictions on the payment of cash dividends by our subsidiaries.

As of December 31, 2005, we had $64 million of cash and cash equivalents compared with $53 million as of December 31, 2004 (each includes $3 million restricted as an indemnity reserve). The major sources for changes in these balances are summarized below.

Cash Flows From Operating Activities

Our consolidated net cash from operating activities is provided primarily by our regulated services and power supply management services businesses (see Results of Operations – Business Segments above). Net cash provided from operating activities was $2.2 billion in 2005, $1.9 billion in 2004 and $1.8 billion in 2003, summarized as follows:

Operating Cash Flows	2005	2004	2003
		(In millions)	
Cash earnings[(1)]	$2,188	$2,197	$1,873
Pension trust contribution[(2)]	(341)	(300)	–
Working capital and other	373	(5)	(96)
Net cash provided from operating activities	$2,220	$1,892	$1,777

[(1)] *Cash earnings are a Non-GAAP measure (see reconciliation below).*
[(2)] *Pension trust contributions in 2005 and 2004 are net of $159 million and $200 million of related current year cash income tax benefits, respectively.*

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

Reconciliation of Cash Earnings	2005	2004	2003
		(In millions)	
Net Income (GAAP)	$ 861	$ 878	$ 423
Non-Cash Charges (Credits):			
Provision for depreciation	589	587	604
Amortization of regulatory assets	1,281	1,166	1,079
Deferral of new regulatory assets	(405)	(257)	(194)
Nuclear fuel and lease amortization	90	96	66
Deferred purchased power and other costs	(384)	(451)	(459)
Deferred income taxes and investment tax credits*	154	58	(18)
Investment impairments	15	30	135
Disallowed regulatory assets	–	–	153
Cumulative effect of accounting changes	30	–	(102)
Deferred rents and lease market valuation liability	(104)	(84)	(119)
Accrued compensation and retirement benefits	90	156	202
Amortization of electric service program	(34)	(18)	(16)
Loss (income) from discontinued operations	(18)	18	123
Other non-cash expenses	23	18	(4)
Cash Earnings (Non-GAAP)	$2,188	$2,197	$1,873

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

Net cash provided from operating activities increased $328 million in 2005 compared to 2004 primarily due to a $378 million increase from changes in working capital and a $9 million decrease in cash earnings as described under "Results of Operations". 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 (under a three-year Energy for Education Program with the Ohio Schools Council). These increases were partially offset by decreases in cash provided from the settlement of receivables of $241 million and the absence of a $53 million NUG power contract restructuring transaction in 2005.

Net cash provided from operating activities increased $115 million in 2004 compared to 2003 due to a $324 million increase in cash earnings as described under "Results of Operations" and a $91 million increase from changes in working capital, partially offset by a $300 million after-tax voluntary pension trust contribution. The increase from working capital changes resulted in part from increases in cash provided from the settlement of receivables of $88 million and prepayments and other current assets of $78 million, decreased outflow of $59 million in payables and a $53 million NUG power contract restructuring transaction, partially offset by an increased outflow of $235 million for tax payments.

Cash Flows From Financing Activities

In 2005, 2004 and 2003, net cash used for financing activities was $876 million, $1.5 billion and $1.3 billion, respectively, primarily reflecting the redemptions of debt and preferred stock shown below:

Securities Issued or Redeemed	2005	2004	2003
		(In millions)	
New Issues			
Common stock	$ –	$ –	$ 934
Pollution control notes	721	261	–
Senior secured notes	–	300	400
Unsecured notes	–	400	627
	$ 721	$ 961	$1,961
Redemptions			
FMB	$ 252	$ 589	$1,483
Pollution control notes	555	80	238
Senior secured notes	94	471	323
Long-term revolving credit	215	95	85
Unsecured notes	308	337	–
Preferred stock	170	2	127
	$1,594	$1,574	$2,256
Short-term borrowings, net	$ 561	$ (351)	$ (575)

We had approximately $731 million of short-term indebtedness as of December 31, 2005 compared to approximately $170 million as of December 31, 2004. The increase in short-term indebtedness in 2005 was due to funding the $341 million after-tax pension trust contribution and refinancing a $300 million senior note in the fourth quarter of 2005. In addition, an off-balance sheet receivables financing agreement was renewed as an on-balance sheet short-term debt financing agreement in June 2005 that had a $140 million indebtedness balance as of December 31, 2005. Available consolidated bank borrowing capacity as of December 31, 2005 included the following:

Borrowing Capability	
	(In millions)
Short-term credit facilities[1]	$2,020
Accounts receivable financing facilities	550
Utilized	(718)
Letters of credit	(101)
Net	$1,751

[1] A $2 billion revolving credit facility that expires in 2010 is available in various amounts to FirstEnergy and certain of its subsidiaries. A $20 million uncommitted line of credit facility added in September 2005 is available to FirstEnergy only.

As of December 31, 2005, the Ohio Companies and Penn had the aggregate capability to issue approximately $1.2 billion of additional FMB on the basis of property additions and retired bonds under the terms of their respective mortgage indentures. The issuance of FMB by OE and CEI are also subject to provisions of their senior note indentures generally limiting the incurrence of additional secured debt, subject to certain exceptions that would permit, among other things, the issuance of secured debt (including FMB) (i) supporting pollution control notes or similar obligations, or (ii) as an extension, renewal or replacement of previously outstanding secured debt. In addition, these provisions would permit OE and CEI to incur additional secured debt not otherwise permitted by a specified exception of up to $651 million and $582 million, respectively, as of December 31, 2005. Under the provisions of its senior note indenture, JCP&L may issue additional FMB only as collateral for senior notes. As of December 31, 2005, JCP&L had the capability to issue $715 million of additional senior notes upon the basis of FMB collateral.

Based upon applicable earnings coverage tests in their respective charters, OE, Penn, TE and JCP&L could issue a total of $5.5 billion of preferred stock (assuming no additional debt was issued) as of December 31, 2005. CEI, Met-Ed and Penelec do not have similar restrictions and could issue up to the number of preferred stock shares authorized under their respective charters (see Note 11(B)).

As of December 31, 2005, approximately $1 billion of capacity remained unused under an existing shelf registration statement, filed by FirstEnergy 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.

Our working capital and short-term borrowing needs are met principally with a $2 billion five-year revolving credit facility (included in the table above). Borrowings under the facility are available to each borrower separately and mature on the earlier of 364 days from the date of borrowing or the commitment expiration date, June 16, 2010.

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	$2,000	$1,500
OE	500	500
Penn	50	44
CEI	250	500
TE	250	500
JCP&L	425	412
Met-Ed	250	300
Penelec	250	300
FES	–[2]	n/a
ATSI	–[2]	26

[1] As of December 31, 2005.

[2] Borrowing sub-limits for FES and ATSI may be increased to 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 ($270 million unused as of December 31, 2005) of accounts receivable financing facilities for OE, CEI, TE, Met-Ed, Penelec and Penn, are intended to provide liquidity to meet short-term working capital requirements 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 $1.75 billion as of December 31, 2005.

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, 2005, FirstEnergy and its subsidiaries' debt to total capitalization ratios (as defined under the revolving credit facility) were as follows:

Borrower	
FirstEnergy	55%
OE	38%
Penn	42%
CEI	53%
TE	28%
JCP&L	26%
Met-Ed	39%
Penelec	36%

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.

Our 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 our unregulated companies. FESC administers these two money pools and tracks surplus funds of FirstEnergy and the respective regulated and unregulated subsidiaries, as well as proceeds available from bank borrowings. 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 2005 was 3.24% for the regulated companies' money pool and 3.22% for the unregulated companies' money pool.

On December 16, 2005, in conjunction with the intra-system generation asset transfers, FirstEnergy made a $750 million cash capital contribution to NGC. NGC used the proceeds from the capital contribution to pre-pay a portion of the promissory notes to CEI and TE for $375 million each. (See Note 15.)

On July 18, 2005, Moody's revised its rating outlook on FirstEnergy and its subsidiaries to positive from stable. Moody's stated that the revision to FirstEnergy's outlook resulted from steady financial improvement and steps taken by management to improve operations, including the stabilization of its nuclear operations. On October 3, 2005, S&P raised its corporate credit rating on FirstEnergy and the Companies to 'BBB' from 'BBB-'. At the same time, S&P raised the senior unsecured ratings at the holding company to 'BBB-' from 'BB+' and each of the Companies by one notch above the previous rating. S&P noted that the upgrade followed the continuation of a good operating track record, specifically for the nuclear fleet through the third quarter of 2005.
On December 23, 2005, Fitch revised its rating outlook on FirstEnergy and its subsidiaries to positive from stable. Fitch stated that the revision to FirstEnergy's outlook resulted from improved performance of the Company's generating fleet and ongoing debt reduction.

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 December 31, 2005. The ratings outlook from S&P on all securities is stable. The ratings outlook from Moody's & Fitch on all securities is positive.

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

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

On 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.

FirstEnergy will consider a share repurchase program later in 2006 after we gain additional clarity on three important milestones:

- The approval of the RCP by the PUCO (received in January 2006);
- Completion of the Beaver Valley Unit 1 extended outage; and
- Finalization of our environmental compliance plan for our fossil plants.

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, 2005 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)			
2005 Sources (Uses)				
Regulated services	$ (788)	$(106)	$(14)	$ (908)
Power supply management services	(375)	(21)	5	(391)
Other	(8)	18	(21)	(11)
Reconciling adjustments	(37)	8	6	(23)
Total	$(1,208)	$(101)	$(24)	$(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)
2003 Sources (Uses)				
Regulated services	$ (434)	$ 94	$ 16	$ (324)
Power supply management services	(335)	(32)	8	(359)
Other	(10)	34	(83)	(59)
Reconciling adjustments	(77)	90	138	151
Total	$ (856)	$ 186	$ 79	$ (591)

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 $153 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 (CD) received in 2004 when the CDs were no longer required as OE sale leaseback LOC collateral.

Net cash used for investing activities in 2004 decreased by $95 million from 2003. The decrease was primarily due to $278 million from certificates of deposit cash proceeds, partially offset by a $117 million change in NUG trust activity.

Our capital spending for the period 2006-2010 is expected to be about $6.7 billion (excluding nuclear fuel), of which $1 billion applies to 2006. Investments for additional nuclear fuel during the 2006-2010 period are estimated to be approximately $711 million, of which about $169 million applies to 2006. During the same period, our nuclear fuel investments are expected to be reduced by approximately $560 million and $92 million, respectively, as the nuclear fuel is consumed.

CONTRACTUAL OBLIGATIONS

As of December 31, 2005, our estimated cash payments under existing contractual obligations that we consider firm obligations are as follows:

Contractual Obligations	Total	2006	2007-2008	2009-2010	Thereafter
			(In millions)		
Long-term debt[1]	$10,200	$1,324	$ 560	$ 467	$ 7,849
Short-term borrowings	731	731	–	–	–
Capital leases[2]	13	5	2	2	4
Operating leases[2]	2,356	202	397	399	1,358
Pension funding[3]	–	–	–	–	–
Fuel and purchased power[4]	15,105	2,844	4,715	3,880	3,666
Total	$28,405	$5,106	$5,674	$4,748	$12,877

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

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

(3) We estimate that no further pension contributions will be required through 2010 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.

(4) 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, 2005, our maximum exposure to potential future payments under outstanding guarantees and other assurances totaled approximately $3.4 billion, as summarized below:

Guarantees and Other Assurances	Maximum Exposure
	(In millions)
FirstEnergy Guarantees of Subsidiaries	
Energy and Energy-Related Contracts[1]	$ 832
Other[2]	894
	1,726
Surety Bonds	312
LOC[3][4]	1,324
Total Guarantees and Other Assurances	$3,362

(1) Issued for open-ended terms, with a 10-day termination right by FirstEnergy.

(2) Issued for various terms.

(3) Includes $101 million issued for various terms under LOC capacity available in FirstEnergy's revolving credit agreement and $604 million 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. The following table summarizes collateral provisions in effect as of December 31, 2005:

Collateral Provisions	Total Exposure	Collateral Paid Cash	Collateral Paid LOC	Remaining Exposure
		(In millions)		
Credit rating downgrade	$380	$78	$ –	$302
Material adverse event	74	–	–	74
Total	$454	$78	$ –	$376

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 ($36 million as of December 31, 2005), which is renewable and declines yearly based upon the senior outstanding debt of TEBSA.

OFF-BALANCE SHEET ARRANGEMENTS

We have obligations that are not included on our Consolidated Balance Sheets related to the sale and leaseback arrangements involving Perry Unit 1, Beaver Valley Unit 2 and the Bruce Mansfield Plant, which are satisfied through operating lease payments. The present value of these sale and leaseback operating lease commitments, net of trust investments, total $1.3 billion as of December 31, 2005.

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.

In June 2005, the CFC accounts receivables financing facility for CEI and TE was renewed and restructured from an off-balance sheet transaction to an on-balance sheet transaction. Under the revised facility, any borrowings by CFC appear on our Consolidated Balance Sheets as short-term debt.

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 primarily due to fluctuations in electricity, energy transmission, natural gas, coal, nuclear fuel and emission allowance prices. To manage the volatility relating to these exposures, we use a variety of non-derivative and derivative instruments, including forward contracts, options, futures contracts and swaps. The derivatives are used principally for hedging purposes. 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 table below. Contracts that are not exempt from such treatment include power purchase agreements with NUG entities that were structured pursuant to the Public Utility Regulatory 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. The change in the fair value of commodity derivative contracts related to energy production during 2005 is summarized in the following table:

Increase (Decrease) in the Fair Value of Derivative Contracts	Non-Hedge	Hedge	Total
Change in the fair value of commodity derivative contracts:		(In millions)	
Outstanding net asset (liability) as of January 1, 2005	$(1,939)	$ 2	$(1,937)
New contract value when entered	–	–	–
Additions/change in value of existing contracts	452	3	455
Change in techniques/assumptions	–	–	–
Settled contracts	316	(2)	314
Sale of retail natural gas contracts	1	(6)	(5)
Outstanding net asset (liability) as of December 31, 2005[1]	(1,170)	(3)	(1,173)
Non-commodity net assets as of December 31, 2005:			
Interest rate swaps[2]	–	(21)	(21)
Net Assets (Liabilities) - Derivative Contracts as of December 31, 2005	$(1,170)	$(24)	$(1,194)
Impact of Changes in Commodity Derivative Contracts[3]			
Income Statement effects (Pre-Tax)	$ 12	$ –	$ 12
Balance Sheet effects:			
OCI (Pre-Tax)	$ –	$ (5)	$ (5)
Regulatory asset (net)	$ (757)	$ –	$ (757)

[1] *Includes $1,183 million 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, 2005 as follows:

Balance Sheet Classification	Non-Hedge	Hedge	Total
		(In millions)	
Current-			
Other assets	$ 4	$ 15	$ 19
Other liabilities	(2)	(19)	(21)
Non-Current-			
Other deferred charges	69	5	74
Other noncurrent liabilities	(1,241)	(25)	(1,266)
Net assets (liabilities)	$(1,170)	$(24)	$(1,194)

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

Source of Information - Fair Value by Contract Year

	2006	2007	2008	2009	2010	Thereafter	Total
	(In millions)						
Prices actively quoted[1]	$(278)	$(297)	$ –	$ –	$ –	$ –	$ (575)
Other external sources[2]	21	10	–	–	–	–	31
Prices based on models	–	–	(260)	(179)	(142)	(48)	(629)
Total[3]	$(257)	$(287)	$(260)	$(179)	$(142)	$(48)	$(1,173)

[1] *Exchange traded.*
[2] *Broker quote sheets.*
[3] *Includes $1,183 million 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, 2005. Based on derivative contracts held as of December 31, 2005, an adverse 10% change in commodity prices would decrease net income by approximately $4 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	2006	2007	2008	2009	2010	There-after	Total	Fair Value
	(Dollars in millions)							
Assets								
Investments other than Cash and Cash Equivalents-Fixed Income	$ 96	$ 77	$ 57	$ 68	$ 84	$1,648	$2,030	$2,135
Average interest rate	6.8%	7.9%	7.7%	7.8%	7.9%	5.9%	6.2%	
Liabilities								
Long-term Debt and Other Long-term Obligations:								
Fixed rate[1]	$1,324	$229	$331	$278	$189	$5,956	$8,307	$8,824
Average interest rate	5.7%	6.6%	5.3%	6.8%	5.4%	6.5%	6.3%	
Variable rate[1]						$1,893	$1,893	$1,892
Average interest rate						3.3%	3.3%	
Short-term Borrowings	$ 731						$731	$ 731
Average interest rate	4.7%						4.7%	

[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 (affecting OCI initially) based on the guidance in SFAS 115. 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, 2005, our decommissioning trust balances totaled $1.8 billion, with $1.3 billion held by NGC and our Ohio Companies and the remaining balance held by JCP&L, Met-Ed and Penelec. As of year-end 2005, the trust balances of NGC and our Ohio Companies were comprised of 61% equity securities and 39% 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 due to lower interest rates. Swap maturities, call options, fixed interest rates and interest payment dates match those of the underlying obligations. During 2005, we entered into interest rate swap agreements on $150 million notional amount of senior notes with a weighted average fixed interest rate of 6.59%. In addition, we unwound swaps with a total notional amount of $700 million from which we received $16 million in cash gains during 2005. The gains will be recognized over the remaining maturity of each respective hedged security as reduced interest expense. As of December 31, 2005, the debt underlying the $1.1 billion outstanding notional amount of interest rate swaps had a weighted average fixed interest rate of 5.71%, which the swaps have effectively converted to a current weighted average variable rate of 5.63%.

	December 31, 2005			December 31, 2004		
Interest Rate Swaps	Notional Amount	Maturity Date	Fair Value	Notional Amount	Maturity Date	Fair Value
	(In millions)					
Fixed to Floating Rate (Fair value hedges)	$ –	2006	$ –	$ 200	2006	$(1)
	100	2008	(3)	100	2008	(1)
	50	2010	–	100	2010	1
	50	2011	–	100	2011	2
	450	2013	(4)	400	2013	4
	–	2014	–	100	2014	2
	150	2015	(9)	150	2015	(7)
	150	2016	–	200	2016	1
	–	2018	–	150	2018	5
	–	2019	–	50	2019	2
	50	2025	(1)	–	2025	–
	100	2031	(5)	100	2031	(4)
	$1,100		$(22)	$1,650		$ 4

Forward Starting Swap Agreements - Cash Flow Hedges

During 2005, we 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 our consolidated entities in 2006 through 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, 2005, we had entered into forward swaps with an aggregate notional amount of $975 million. As of December 31, 2005 the forward swaps had a fair value of $3 million.

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

Equity Price Risk

Included in nuclear decommissioning trusts are marketable equity securities carried at their current fair value of approximately $1.1 billion and $951 million as of December 31, 2005 and 2004, respectively. A hypothetical 10% decrease in prices quoted by stock exchanges would result in a $107 million reduction in fair value as of December 31, 2005 (see Note 5 – Fair Value of Financial Instruments).

CREDIT RISK

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

We maintain credit policies with respect to our counterparties to manage overall credit risk. This includes performing independent risk evaluations, actively monitoring portfolio trends and using collateral and contract provisions to mitigate exposure. As part of our credit program, we aggressively manage the quality of our portfolio of energy contracts, evidenced by a current weighted average risk rating for energy contract counterparties of BBB (S&P). As of December 31, 2005, the largest credit concentration with one party (currently rated investment grade) represented 7.6% 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, 2005.

REGULATORY MATTERS

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. The following tables disclose the regulatory assets by company and by source:

Regulatory Assets As of December 31	2005	2004	Increase (Decrease)
		(In millions)	
OE	$ 775	$1,116	$ (341)
CEI	862	944	(82)
TE	287	366	(79)
JCP&L	2,227	2,169	58
Met-Ed	310	691	(381)
Penelec	–	200	(200)
ATSI	25	13	12
Total	$4,486	$5,499	$(1,013)

* *Penn had net regulatory liabilities of approximately $59 million and $19 million as of December 31, 2005 and 2004, respectively; changes in Penelec's net regulatory asset components in 2005 resulted in it having net regulatory liabilities of approximately $163 million as of December 31, 2005. These net regulatory liabilities are included in Other Noncurrent Liabilities on the Consolidated Balance Sheets as of December 31, 2005 and 2004.*

Regulatory Assets By Source As of December 31	2005	2004	Increase (Decrease)
		(In millions)	
Regulatory transition costs	$3,576	$4,889	$(1,313)
Customer shopping incentives	884	612	272
Customer receivables for future income taxes	217	246	(29)
Societal benefits charge	29	51	(22)
Loss on reacquired debt	41	56	(15)
Employee postretirement benefits costs	55	65	(10)
Nuclear decommissioning, decontamination and spent fuel disposal costs	(126)	(169)	43
Asset removal costs	(365)	(340)	(25)
Property losses and unrecovered plant costs	29	50	(21)
MISO transmission costs	91	–	91
JCP&L reliability costs	23	–	23
Other	32	39	(7)
Total	$4,486	$5,499	$(1,013)

Ohio

On May 27, 2005, the Ohio Companies filed an application with the PUCO to establish a GCAF rider under the RSP which had been approved by the PUCO in August 2004. The GCAF application sought recovery of increased fuel costs from 2006 through 2008 applicable to the Ohio Companies' retail customers through a tariff rider to be implemented January 1, 2006. The application reflected projected increases in fuel costs in 2006 compared to 2002 baseline costs. The new rider, after adjustments made in testimony, sought to recover all costs above the baseline (approximately $88 million in 2006). Various parties including the OCC intervened in this case and the case was consolidated with the RCP application discussed below. On November 1, 2005, the Ohio Companies filed tariffs in compliance with the RSP, which were approved by the PUCO on December 7, 2005.

On September 9, 2005, the Ohio Companies filed an application with the PUCO that supplemented their existing RSP with an RCP which was designed to provide customers with more certain rate levels than otherwise available under the RSP during the plan period. Major provisions of the RCP include:

- Maintain the existing level of base distribution rates through December 31, 2008 for OE and TE, and April 30, 2009 for CEI;
- Defer and capitalize for future recovery 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;
- Adjust 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;

- Reduce 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
- Recover increased fuel costs 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 increased fuel costs above the amount collected through the fuel recovery mechanism (in lieu of implementation of the GCAF rider).

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 2006 through 2010:

Amortization Period	OE	CEI	TE	Total Ohio
		(In millions)		
2006	$169	$100	$ 80	$ 349
2007	176	111	89	376
2008	198	129	100	427
2009	–	216	–	216
2010	–	268	–	268
Total Amortization	$543	$824	$269	$1,636

On November 4, 2005, a supplemental stipulation was filed with the PUCO which was in addition to a stipulation filed with the September 9, 2005 application. On January 4, 2006, the PUCO approved the RCP filing with modifications. On January 10, 2006, the Ohio Companies filed a Motion for Clarification of the PUCO order approving the RCP. The Ohio Companies sought clarity on issues related to distribution deferrals, including requirements of the review process, timing for recognizing certain deferrals and definitions of the types of qualified expenditures. The Ohio Companies also sought confirmation that the list of deferrable distribution expenditures originally included in the revised stipulation fall within the PUCO order definition of qualified expenditures. 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: 1) recognize fuel and distribution deferrals commencing January 1, 2006; 2) recognize distribution deferrals on a monthly basis prior to review by the PUCO Staff; 3) clarify that the types of distribution expenditures included in the Supplemental Stipulation may be deferred; and 4) clarify that distribution expenditures do not have to be "accelerated" in order to be deferred. The PUCO granted 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 Companies' Motion. On February 3, 2006, several other parties filed applications for rehearing on the PUCO's January 4, 2006 Order. The Ohio Companies responded to the application for rehearing on February 13, 2006.

Under provisions of the RSP, the PUCO may require the Ohio Companies to undertake, no more often than annually, a competitive bid process to secure generation for the years 2007 and 2008. On July 22, 2005, we filed a competitive bid process for the period beginning in 2007 that is similar to the competitive bid process approved by the PUCO for the Ohio Companies in 2004 which resulted in the PUCO accepting no bids. Any acceptance of future competitive bid results would terminate the RSP pricing, with no accounting impacts to the RSP, and not until twelve months after the PUCO authorizes such termination. On September 28, 2005, the PUCO issued an Entry that essentially approved the Ohio Companies' filing but delayed the proposed timing of the competitive bid process by four months, calling for the auction to be held on March 21, 2006. OCC filed an application for rehearing of the September 28, 2005 Entry, which the PUCO denied on November 22, 2005. On February 23, 2006, the auction manager notified the PUCO that there was insufficient interest in the auction process to allow it to proceed in 2006.

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

Pennsylvania

As of December 31, 2005, 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 are $333 million and $48 million, respectively. Penelec's $48 million is subject to the pending resolution of taxable income issues associated with NUG Trust Fund proceeds.

Met-Ed and Penelec purchase a portion of their PLR requirements from FES through a wholesale power sales agreement and a portion from contracts with unaffiliated third party suppliers, including NUGs. Assuming continuation of these existing contractual arrangements, the available supply represents approximately 100% of the combined retail sales obligations of Met-Ed and Penelec in 2006 and 2007; almost 100% for 2008; and approximately 85% for 2009 and 2010. Met-Ed and Penelec are authorized to defer any excess of NUG contract costs over current market prices. Under the terms of the wholesale agreement with FES, FES retains the supply obligation and the supply profit and loss risk for the portion of power supply requirements not self-supplied by Met-Ed and Penelec under their contracts with NUGs and other unaffiliated suppliers. This arrangement reduces Met-Ed's and Penelec's exposure to high wholesale power prices by providing power at a fixed price for their uncommitted PLR energy costs during the term of the agreement with FES. The wholesale agreement with FES is automatically extended for each successive calendar year unless any party elects to cancel the agreement by November 1 of the preceding year. On November 1, 2005, FES and the other parties thereto amended the agreement to provide FES the right over the next year to terminate the agreement at any time upon 60 days notice. If the wholesale power agreement were terminated or modified, Met-Ed and Penelec would need to satisfy the portion of their PLR obligations currently supplied by FES from unaffiliated suppliers at prevailing prices, which are likely to be higher than the current price charged by FES under the agreement and, as a result, Met-Ed's and Penelec's purchased power costs could materially increase. If Met-Ed and Penelec were to replace the 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 support an investment grade rating for its fixed income securities. Met-Ed and Penelec are in the process of preparing a comprehensive rate filing that will address a number of transmission, distribution and supply issues and is expected to be filed with the PPUC in the second quarter of 2006. That filing will include, among other things, a request for appropriate regulatory action to mitigate adverse consequences from any future reduction, in whole or in part, in the availability to Met-Ed and Penelec of supply under the existing FES agreement. There can be no assurance, however, that if FES ultimately determines to terminate, or significantly modify the agreement, timely regulatory relief will be granted by the PPUC or, to the extent granted, adequate to mitigate such adverse consequences.

On October 11, 2005, Penn filed a plan with the PPUC to secure electricity supply for its customers at set rates following the end of its transition period on December 31, 2006. Penn is recommending that an RFP process cover the period January 1, 2007 through May 31, 2008. Hearings were held on January 10, 2006 with main briefs filed on January 27, 2006 and reply briefs on February 3, 2006. On February 17, 2006, the ALJ issued a Recommended Decision to adopt Penn's RFP process with modifications. A PPUC vote is expected in April 2006. Under Pennsylvania's electric competition law, Penn is required to secure generation supply for customers who do not choose alternative suppliers for their electricity.

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

New Jersey

JCP&L is permitted to defer for future collection from customers the amounts by which its costs of supplying BGS to non-shopping customers and costs incurred under NUG agreements exceed amounts collected through BGS and MTC rates and market sales of NUG energy and capacity. As of December 31, 2005, the accumulated deferred cost balance totaled approximately $541 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. JCP&L is in discussions with the NJBPU staff as a result of the stipulated settlement agreements (as further discussed below) which recommended that the NJBPU issue an order regarding JCP&L's application. On July 20, 2005, JCP&L requested the NJBPU to set a procedural schedule for this matter and is awaiting NJBPU action. On February 1, 2006, the NJBPU selected Bear Stearns as the financial advisor. On December 2, 2005, JCP&L filed a request for recovery of $165 million of actual above-market NUG costs incurred from August 1, 2005 through October 31, 2005 and forecasted above-market NUG costs for November and December 2005. The filing also includes a request for recovery of $49 million for above-market NUG costs incurred prior to August 1, 2003, to the extent those costs are not recoverable through securitization.

On May 25, 2005, the NJBPU approved two stipulated settlement agreements. The first stipulation between JCP&L and the NJBPU staff resolves all of the issues associated with JCP&L's motion for reconsideration of the 2003 NJBPU decision on JCP&L's base electric rate proceeding (Phase I Order). The second stipulation between JCP&L, the NJBPU staff and the Ratepayer Advocate resolves all of the issues associated with JCP&L's Phase II petition requesting an increase in base rates of $36 million for the recovery of system reliability costs and a 9.75% return on equity. The stipulated settlements provide for, among other things, the following:

- An annual increase in distribution revenues of $23 million, effective June 1, 2005, associated with the Phase I Order reconsideration;
- An annual increase in distribution revenues of $36 million, effective June 1, 2005, related to JCP&L's Phase II Petition;
- An annual reduction in both rates and amortization expense of $8 million, effective June 1, 2005, in anticipation of an NJBPU order regarding JCP&L's request to securitize up to $277 million of its deferred cost balance;
- An increase in JCP&L's authorized return on common equity from 9.5% to 9.75%; and
- A commitment by JCP&L, through December 31, 2006 or until related legislation is adopted, whichever occurs first, to maintain a target level of customer service reliability with a reduction in JCP&L's authorized return on common equity from 9.75% to 9.5% if the target is not met for two consecutive quarters. The authorized return on common equity would then be restored to 9.75% if the target is met for two consecutive quarters.

The Phase II stipulation included an agreement that the distribution revenue increase also reflects a three-year amortization of JCP&L's one-time service reliability improvement costs incurred in 2003-2005. This resulted in the creation of a regulatory asset associated with accelerated tree trimming and other reliability costs which were expensed in 2003 and 2004. The establishment of the new regulatory asset of approximately $28 million resulted in an increase to net income of approximately $16 million ($0.05 per share of FirstEnergy common stock) in the second quarter of 2005.

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 recent repeal of PUHCA under the EPACT. An NJBPU proposed rulemaking to address the issues was published in the NJ Register on December 19, 2005. The proposal 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. A public hearing was held on February 7, 2006 and comments to the NJBPU were due by February 17, 2006.

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

Transmission

ATSI, JCP&L, Met-Ed, Penelec, and FES continue to be involved in FERC hearings concerning the calculation and imposition of Seams Elimination Cost Adjustment (SECA) charges to various load serving entities. Pursuant to its January 30, 2006 Order, the FERC has compressed both phases of this proceeding into a single hearing scheduled to begin May 1, 2006, with an initial decision on or before August 11, 2006.

On November 1, 2004, ATSI requested authority from the FERC to defer approximately $54 million of vegetation management costs estimated to be incurred from 2004 through 2007. On March 4, 2005, the FERC approved ATSI's request to defer those costs ($26 million deferred as of December 31, 2005). ATSI expects to file a rate application with the FERC that would include recovery of the deferred costs beginning in June 2006.

On January 24, 2006, ATSI and MISO filed an application with the FERC to modify the Attachment O formula rate mechanism to permit ATSI to accelerate recovery of revenues lost due to the FERC's elimination of through and out rates between MISO and PJM, and the elimination of other ATSI rates in the MISO tariff. Revenues formerly collected under these rates are currently used to reduce the ATSI zonal transmission rate in the Attachment O formula. The revenue shortfall created by elimination of these rates would not be fully reflected in ATSI's formula rate until June 1, 2006, unless the proposed Revenue Credit Collection is approved by the FERC. The Revenue Credit Collection mechanism is designed to collect approximately $40 million in revenues on an annualized basis beginning June 1, 2006. FERC is expected to act on this filing on or before April 1, 2006.

On August 31, 2005, the PUCO approved the Ohio Companies' settlement stipulation for a rider to recover transmission and ancillary service-related costs beginning January 1, 2006, to be adjusted each July 1 thereafter. The incremental transmission and ancillary service revenues expected to be recovered from January through June 2006 are approximately $66 million, including recovery of the 2005 deferred MISO expenses as described below. In May 2006, the Ohio Companies will file a modification to the rider to determine revenues from July 2006 through June 2007. On January 20, 2006, the OCC sought rehearing of the PUCO approval of the rider recovery during the period January 1, 2006 through June 30, 2006, as that amount pertains to recovery of the deferred costs. The PUCO denied the OCC's application on February 6, 2006. The OCC has sixty days from that date to appeal the PUCO's approval of the rider.

In response to the Ohio Companies' December 2004 application for authority to defer costs associated with transmission and ancillary service-related costs incurred during the period October 1, 2003 through December 31, 2005, the PUCO granted the accounting authority in May 2005 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. All briefs have been filed. A motion to dismiss filed on behalf of the PUCO is currently pending. Unless the court grants the motion, the appeal will be set for oral argument, which should be heard in the second half of 2006.

On January 12, 2005, Met-Ed and Penelec filed a request with the PPUC for deferral of transmission-related costs beginning January 1, 2005, estimated to be approximately $8 million per month. The OCA, OSBA, OTS, MEIUG, PICA, Allegheny Electric Cooperative and Pennsylvania Rural Electric Association have all intervened in the case. To date no hearing schedule has been established, and neither company has yet implemented deferral accounting for these costs.

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. Second, the FERC approved the proposed Schedule 12 rate harmonization. Third, the FERC accepted the proposed formula rate, subject to referral and hearing procedures. On June 30, 2005, the settling PJM transmission owners filed a request for rehearing of the May 31, 2005 order. The rate design and formula rate proceedings are currently being litigated before the FERC. If the FERC accepts a proposal by American Electric Power Company, Inc. to create a "postage stamp" rate for high voltage transmission facilities across PJM, significant additional transmission revenues would be imposed on JCP&L, Met-Ed, Penelec, and other transmission zones within PJM.

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 competitive bid process, mandated by the PUCO, 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. Penn has filed a plan with the PPUC to use an RFP process to obtain its power supply requirements after 2006.

On December 29, 2005, the FERC issued an order setting the two power sales agreements for hearing. The order criticizes the Ohio competitive bid process, and requires FES to submit additional evidence in support of the reasonableness of the prices charged in the two power sales agreements. A pre-hearing conference was held on January 18, 2006 to determine the hearing schedule in this case. FES expects an initial decision to be issued in this case in the fall of 2006. The outcome of this proceeding cannot be predicted. FES has sought rehearing of the December 29, 2005 order.

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 coordinators, however, may take a different view as to recommended enhancements or may recommend additional enhancements in the future as the result of adoption of mandatory reliability standards pursuant to EPACT that could require additional, material expenditures. Finally, the PUCO is continuing to review our filing that addressed upgrades to control room computer hardware and software and enhancements to the training of control room operators before determining the next steps, if any, in the proceeding.

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 and a timetable for completion of actions related to service reliability to be performed by JCP&L and also approved a Stipulation that incorporates the final report of a Special Reliability Master who made recommendations on appropriate courses of action necessary to ensure system-wide reliability. JCP&L continues to file compliance reports reflecting activities associated with the MOU and Stipulation.

In May 2004, the PPUC issued an order approving revised reliability benchmarks and standards, including revised benchmarks and standards for Met-Ed, Penelec and Penn. Met-Ed, Penelec and Penn filed a Petition for Amendment of Benchmarks with the PPUC on May 26, 2004, due to their implementation of automated outage management systems following restructuring. On December 30, 2005, the ALJ recommended that the PPUC adopt the Joint Petition for Settlement among the parties involved in the three Companies' request to amend the distribution reliability benchmarks, thereby eliminating the need for full litigation. The ALJ's recommendation, adopting the revised benchmarks and standards was approved by the PPUC on February 9, 2006.

EPACT provides for the creation of an ERO to establish and enforce reliability standards for the bulk power system, subject to FERC review. On February 3, 2006, the FERC adopted a rule establishing certification requirements for the ERO, as well as regional entities envisioned to assume monitoring responsibility for the new reliability standards.

The NERC has been preparing the implementation aspects of reorganizing its structure to meet the FERC's certification requirements for the ERO. The NERC will make a filing with the FERC to obtain certification as the ERO and to obtain FERC approval of delegation agreements with regional entities. The new FERC rule referred to above, further provides for reorganizing regional reliability organizations (regional entities) that would replace the current regional councils and for rearranging the relationship with the ERO. The "regional entity" may be delegated authority by the ERO, subject to FERC approval, for enforcing reliability standards adopted by the ERO and approved by the FERC. NERC also intends to make a parallel filing with the FERC seeking approval of mandatory reliability standards. These reliability standards are expected to be based on the current NERC Version 0 reliability standards with some additional standards. The two filings are expected to be made in the second quarter of 2006.

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

On a parallel path, the NERC is establishing working groups to develop reliability standards to be filed for approval with the FERC following the NERC's certification as an ERO. These reliability standards are expected to build on the current NERC Version 0 reliability standards. It is expected that the proposed reliability standards will be filed with the FERC in early 2006.

We believe that we are in compliance with all current NERC reliability standards. However, it is expected that the FERC will adopt stricter reliability standards than those contained in the current NERC Version 0 standards. The financial impact of complying with the new standards cannot be determined at this time. However, EPACT requires 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 the 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 are both probable and reasonably estimable.

On December 1, 2005, we issued a comprehensive report to shareholders regarding air emissions regulations and an assessment of our future risks and mitigation efforts. The report is available on our web site at www.firstenergycorp.com/environmental.

National Ambient Air Quality Standards

In July 1997, the EPA promulgated changes in the NAAQS for ozone and proposed a new NAAQS for fine particulate matter. On March 10, 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 provides each affected state until 2006 to develop implementing regulations to achieve additional reductions of NOx and SO_2 emissions in two phases (Phase I in 2009 for NOx, 2010 for SO_2 and Phase II in 2015 for both NOx and SO_2). Our Michigan, Ohio and Pennsylvania fossil-fired generation facilities will be subject to caps on SO_2 and NOx emissions, whereas our New Jersey fossil-fired generation facilities will be subject to a cap on NOx 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. NOx 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 NOx 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 the Companies operate affected facilities.

Mercury Emissions

In December 2000, the EPA announced it would proceed with the development of regulations regarding hazardous air pollutants from electric power plants, identifying mercury as the hazardous air pollutant of greatest concern. On March 14, 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 NOx 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. Since this approach is based on output, new and non-emitting generating facilities, including renewables and nuclear, would be entitled to their proportionate share of the allowances. Consequently, we would be disadvantaged if these model rules were implemented because our substantial reliance on non-emitting (largely nuclear) generation is not recognized under input-based allocation.

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 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 W. H. Sammis Plant New Source Review litigation. This settlement agreement was approved by the Court on July 11, 2005, and requires reductions of NOx and SO_2 emissions at the W. H. Sammis Plant and other 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 settlement agreement. Capital expenditures necessary to meet those requirements are currently estimated to be $1.5 billion (the primary portion of which is expected to be spent in the 2008 to 2011 time period). On August 26, 2005, FGCO entered into an agreement with Bechtel Power Corporation (Bechtel), under which Bechtel will engineer, procure, and construct air quality control systems for the reduction of sulfur dioxide emissions. The settlement agreement also requires OE and Penn to spend up to $25 million toward environmentally beneficial projects, which include wind energy purchased power agreements over a 20-year term. OE and Penn agreed to pay a civil penalty of $8.5 million. Results in 2005 included the penalties payable by OE and Penn of $7.8 million and $0.7 million, respectively. OE and Penn also recognized liabilities 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. 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 the Companies is lower than many regional competitors due to the Companies' diversified generation sources which include low or non-CO_2 emitting gas-fired and nuclear generators.

Regulation of Hazardous Waste

The Companies have been named as PRPs at waste disposal sites, which may require cleanup under the Comprehensive Environmental Response, Compensation, and Liability Act of 1980. Allegations of disposal of hazardous substances at historical sites and the liability involved are often unsubstantiated and subject to dispute; however, federal law provides that all PRPs for a particular site are liable on a joint and several basis. Therefore, environmental liabilities that are considered probable have been recognized on the Consolidated Balance Sheet as of December 31, 2005, based on estimates of the total costs of cleanup, our 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 $64 million have been accrued through December 31, 2005.

See Note 14(C) 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 concludes, 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 website (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 also are proceeding with the implementation of the recommendations regarding enhancements to regional reliability 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, and therefore we have not accrued a liability as of December 31, 2005 for any expenditures in excess of those actually incurred through that date. We note, however, that the FERC or other applicable government agencies and reliability coordinators may take a different view as to recommended enhancements or may recommend additional enhancements in the future that could require additional, material expenditures. Finally, the PUCO is continuing to review our filing that addressed upgrades to control room computer hardware and software and enhancements to the training of control room operators before determining the next steps, if any, in the proceeding.

FirstEnergy companies also are defending six separate complaint cases before the PUCO relating to the August 14, 2003 power outage. 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. Of the four other pending PUCO complaint cases, three were filed by various insurance carriers either in their own name as subrogees or in the name of their insured. In each of the four 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 claims 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. The fourth case involves the claim of a non-customer seeking reimbursement for losses incurred when its store was burglarized on August 14, 2003. In addition to these six cases, the Ohio Companies were named as respondents in a regulatory proceeding that was initiated at the PUCO in response to complaints alleging failure to provide reasonable and adequate service stemming primarily from the August 14, 2003 power outages. No estimate of potential liability is available for any of these cases.

In addition to the above proceedings, FirstEnergy was named in a complaint filed in Michigan State Court by an individual who is not a customer of any FirstEnergy company. A responsive pleading to this matter has been filed. FirstEnergy was also named, along with several other entities, in a complaint in New Jersey State Court. The allegations against FirstEnergy are based, in part, on an alleged failure to protect the citizens of Jersey City from an electrical power outage. No FirstEnergy entity serves any customers in Jersey City. A responsive pleading has been filed. No estimate of potential liability has been undertaken in either of these matters.

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 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 our financial condition, results of operations and cash flows.

Nuclear Plant Matters

On January 20, 2006, FENOC announced that it has 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, which expires on December 31, 2006, 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 will 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 remains in compliance with the agreement, which FENOC fully intends to do. FENOC has agreed to pay a penalty of $28 million (which is not deductible for income tax purposes) which reduced FirstEnergy's earnings by $0.09 per common share in the fourth quarter of 2005. As part of the deferred prosecution agreement entered into with the DOJ, $4.35 million of that amount will be directed to community service projects.

On April 21, 2005, the NRC issued a NOV and proposed a $5 million civil penalty related to the degradation of the Davis-Besse reactor vessel head issue described 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.

Effective July 1, 2005 the NRC oversight panel for Davis-Besse was terminated and Davis-Besse returned to the standard NRC reactor oversight process. At that time, NRC inspections were augmented to include inspections to support the NRC's Confirmatory Order dated March 8, 2004 that was issued at the time of startup and to address an NRC White Finding related to the performance of the emergency sirens. By letter dated December 8, 2005, the NRC advised FENOC that the White Finding had been closed.

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. FENOC operates the Perry Nuclear Power Plant.

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 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. By an inspection report dated January 18, 2006, the NRC closed one of the White Findings (related to emergency preparedness) which led to the multiple degraded cornerstones.

On May 26, 2005, the NRC held a public meeting to discuss its oversight of the Perry Plant. While the NRC stated that the plant continued to operate safely, the NRC also stated that the overall performance had not substantially improved since the heightened inspection was initiated. The NRC reiterated this conclusion in its mid-year assessment letter dated August 30, 2005. On September 28, 2005, the NRC sent a

CAL to FENOC describing commitments that FENOC had made to improve the performance of Perry 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. 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 unable to predict a potential impact, its ultimate disposition could have a material adverse effect on FirstEnergy's or its subsidiaries' financial condition, results of operations and cash flows.

As of December 16, 2005, NGC acquired ownership of the nuclear generation assets transferred from OE, CEI, TE and Penn with the exception of leasehold interests of OE and TE in certain of the nuclear plants that are subject to sale and leaseback arrangements with non-affiliates.

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 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 we have provided. We have cooperated fully with the informal inquiry and will 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.

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 Arbitrator decided not to hear testimony on damages and closed the proceedings. On September 9, 2005, the Arbitrator issued an opinion to award approximately $16 million to the bargaining unit employees. On February 6, 2006, the federal court granted a Union motion to dismiss JCP&L's appeal of the award as premature. JCP&L will file its 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.

The City of Huron filed a complaint against OE with the PUCO challenging the ability of electric distribution utilities to collect transition charges from a customer of a newly formed municipal electric utility. The complaint was filed on May 28, 2003, and OE timely filed its response on June 30, 2003. In a related filing, the Ohio Companies filed for approval with the PUCO a tariff that would specifically allow the collection of transition charges from customers of municipal electric utilities formed after 1998. An adverse ruling could negatively affect full recovery of transition charges by the utility. Hearings on the matter were held in August 2005. Initial briefs from all parties were filed on September 22, 2005 and reply briefs were filed on October 14, 2005. It is unknown when the PUCO will decide this case.

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 our financial condition, results of operations and cash flows.

See Note 14(D) 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 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.

In selecting an assumed discount rate, we consider currently available rates of return on high-quality fixed income investments expected to be available during the period to maturity of the pension and other postretirement benefit obligations. Due to declines in corporate bond yields and interest rates in general, we reduced the assumed discount rate as of December 31, 2005 to 5.75% from 6.00% and 6.25% used as of December 31, 2004 and 2003, 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 2005, 2004 and 2003, our qualified pension plan assets actually earned $325 million or 8.2%, $415 million or 11.1% and $671 million or 24.2%, respectively. Our qualified pension costs in 2005, 2004 and 2003 were computed using an assumed 9.0% rate of return on plan assets which generated $345 million, $286 million and $248 million expected returns on plan assets, respectively. The 2005 expected return was based upon projections of future returns and our pension trust investment allocation of approximately 63% equities, 33% bonds, 2% real estate and 2% 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.

Using an expected rate of return on plan assets of 9.0%, we expect our qualified pension expense to be approximately $94 million in 2006. This compares to $131 million in 2005 and $194 million in 2004.

Pension expense in our non-qualified pension plans is expected to be approximately $19 million in 2006, compared to $16 million in 2005 and $14 million in 2004.

In the fourth quarter of 2005, we made a $500 million voluntary contribution to our pension plan. As a result of our voluntary contribution and the increased market value of pension plan assets, we recognized a prepaid benefit cost of $1 billion as of December 31, 2005. As prescribed by SFAS 87, we eliminated our additional minimum liability of $567 million and our intangible asset of $63 million. In addition, the entire AOCL balance was credited by $295 million (net of $208 million of deferred taxes) as the fair value of trust assets exceeded the accumulated benefit obligation as of December 31, 2005.

Health care cost trends continue to increase and will affect future OPEB costs. The 2005 and 2004 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%	$10	$ 5	$15
Long-term return on assets	Decrease by 0.25%	$10	$ 1	$11
Health care trend rate	Increase by 1%	na	$41	$41

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 will be 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 2005 with no impairment indicated.

SFAS 142 requires the goodwill of a reporting unit to be tested for impairment if there is a more-likely-than-not expectation that the reporting unit or a significant asset group within the reporting unit will be sold. In December 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 is no corresponding income tax benefit). In December 2004, the FSG subsidiaries qualified as an asset held for sale, resulting in a non-cash charge of $36 million ($30 million, net of tax) in the fourth quarter of 2004.

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

NEW ACCOUNTING STANDARDS AND INTERPRETATIONS

FSP FAS 115-1 and FAS 124-1, "The Meaning of Other-Than-Temporary Impairment and its Application to Certain Investments"

Issued in November 2005, FSP 115-1 and FAS 124-1 addresses the determination as to when an investment is considered impaired, whether that impairment is other than temporary, and the measurement of an impairment loss. The FSP finalized and renamed EITF 03-1 and 03-1-a to FSP FAS 115-1. This FSP will (1) nullify certain requirements of Issue 03-1 and supersedes EITF topic No. D-44, "Recognition of Other Than Temporary Impairment upon the Planned Sale of a Security Whose Cost Exceeds Fair Value," (2) clarify that an investor should recognize an impairment loss no later than when the impairment is deemed other than temporary, even if a decision to sell has not been made, and (3) be effective for other-than-temporary impairment and analyses conducted in periods beginning after September 15, 2005. The FSP requires prospective application with an effective date for reporting periods beginning after December 15, 2005. We are currently evaluating this FSP Issue and any impact on our investments.

FSP No. FAS 13-1, "Accounting for Rental Costs Incurred during the Construction Period"

Issued in October 2005, FSP No. FAS 13-1 requires rental costs associated with ground or building operating leases that are incurred during a construction period to be recognized as rental expense. The effective date of the FSP guidance is the first reporting period beginning after December 15, 2005. We will apply this FSP to all construction projects, new and in progress, beginning after January 1, 2006.

EITF Issue 04-13, "Accounting for Purchases and Sales of Inventory with the Same Counterparty"

In September 2005, the EITF reached a final consensus on Issue 04-13 concluding that two or more legally separate exchange transactions with the same counterparty should be combined and considered as a single arrangement for purposes of applying APB 29, when the transactions were entered into "in contemplation" of one another. If two transactions are combined and considered a single arrangement, the EITF reached a consensus that an exchange of inventory should be accounted for at fair value. Although electric power is not capable of being held in inventory, there is no substantive conceptual distinction between exchanges involving power and other storable inventory. Therefore, we will adopt this EITF effective for new arrangements entered into, or modifications or renewals of existing arrangements, in interim or annual periods beginning after March 15, 2006.

SFAS 154 – "Accounting Changes and Error Corrections – a replacement of APB Opinion No. 20 and FASB Statement No. 3"

In May 2005, the FASB issued SFAS 154 to change the requirements for accounting and reporting a change in accounting principle. It applies to all voluntary changes in accounting principle and to changes required by an accounting pronouncement when that pronouncement does not include specific transition provisions. This Statement requires retrospective application to prior periods' financial statements of changes in accounting principle, unless it is impracticable to determine either the period-specific effects or the cumulative effect of the change. In those instances, this Statement requires that the new accounting principle be applied to the balances of assets and liabilities as of the beginning of the earliest period for which retrospective application is practicable and that a corresponding adjustment be made to the opening balance of retained earnings (or other appropriate components of equity or net assets in the statement of financial position) for that period rather than being reported in the Consolidated Statements of Income. This Statement also requires that a change in depreciation, amortization, or depletion method for long-lived, nonfinancial assets be accounted for as a change in accounting estimate affected by a change in accounting principle. The provisions of this Statement are effective for accounting changes and corrections of errors made in fiscal years beginning after December 15, 2005. We adopted this Statement effective January 1, 2006.

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

In December 2004, the FASB issued SFAS 153 amending APB 29, which was based on the principle that nonmonetary assets should be measured based on the fair value of the assets exchanged. The guidance in APB 29 included certain exceptions to that principle. SFAS 153 eliminates the exception from fair value measurement for nonmonetary exchanges of similar productive assets and replaces it with an exception for exchanges that do not have commercial substance. This Statement specifies that a nonmonetary exchange has commercial substance if the future cash flows of the entity are expected to change significantly as a result of the exchange. The provisions of this Statement are effective January 1, 2006 for FirstEnergy. This FSP is not expected to have a material impact on our financial statements.

SFAS 123(R), "Share-Based Payment"

In December 2004, the FASB issued SFAS 123(R), a revision to SFAS 123, which requires expensing stock options in the financial statements. Important to applying the new standard is understanding how to (1) measure the fair value of stock-based compensation awards and (2) recognize the related compensation cost for those awards. For an award to qualify for equity classification, it must meet certain criteria in SFAS 123(R). An award that does not meet those criteria will be classified as a liability and remeasured each period. SFAS 123(R) retains SFAS 123's requirements on accounting for income tax effects of stock-based compensation. In April 2005, the SEC delayed the effective date of SFAS 123(R) to annual, rather than interim, periods that begin after June 15, 2005. We adopted this Statement effective January 1, 2006 with modified prospective application. We use the Black-Scholes option-pricing model to value options for disclosure purposes only and continued to apply this pricing model with the adoption of SFAS 123(R). As discussed in Note 4, we reduced our use of stock options beginning in 2005, with no stock options being awarded subsequent to 2004. As a result, all currently unvested stock options will vest by 2008. We expect the adoption of SFAS 123(R) will increase annual compensation expense (after-tax) by approximately $7 million, $2 million and $0.5 million in 2006, 2007 and 2008, respectively or $0.02 per share in 2006 and less than $0.01 per share in 2007 and 2008.

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

In November 2004, the FASB issued SFAS 151 to clarify the accounting for abnormal amounts of idle facility expense, freight, handling costs and wasted material (spoilage). Previous guidance stated that in some circumstances these costs may be "so abnormal" that they would require treatment as current period costs. SFAS 151 requires abnormal amounts for these items to always be recorded as current period costs. In addition, this Statement requires that allocation of fixed production overheads to the cost of conversion be based on the normal capacity of the production facilities. The provisions of this statement are effective for inventory costs incurred by us beginning January 1, 2006. We do not expect it to have a material impact on the financial statements.

Consolidated Statements of Income

(In millions, except per share amounts)

For the Years Ended December 31,	2005	2004	2003
REVENUES:			
Electric utilities	$9,704	$8,860	$8,777
Unregulated businesses	2,285	3,200	2,548
Total revenues	11,989	12,060	11,325
OPERATING EXPENSES AND TAXES:			
Fuel and purchased power	4,011	4,469	4,159
Other operating expenses	3,725	3,374	3,640
Claim settlement (Note 8)	–	–	(168)
Provision for depreciation	589	587	604
Amortization of regulatory assets	1,281	1,166	1,079
Deferral of new regulatory assets	(405)	(257)	(194)
Goodwill impairment	9	12	91
General taxes	713	678	638
Total expenses	9,923	10,029	9,849
OPERATING INCOME	2,066	2,031	1,476
OTHER INCOME (EXPENSE):			
Investment income	218	205	185
Interest expense	(661)	(671)	(799)
Capitalized interest	19	25	32
Subsidiaries' preferred stock dividends	(15)	(21)	(42)
Total other income (expense)	(439)	(462)	(624)
INCOME TAXES	754	673	408
INCOME BEFORE DISCONTINUED OPERATIONS AND CUMULATIVE EFFECT OF ACCOUNTING CHANGES	873	896	444
Discontinued operations (net of income taxes (benefit) of ($9 million), $1 million and ($3 million) respectively) (Note 2(J))	18	(18)	(123)
Cumulative effect of accounting changes (net of income taxes (benefit) of ($17 million) and$72 million, respectively) (Note 2(K))	(30)	–	102
NET INCOME	$ 861	$ 878	$ 423
BASIC EARNINGS PER SHARE OF COMMON STOCK:			
Income before discontinued operations and cumulative effect of accounting changes	$ 2.66	$ 2.74	$ 1.46
Discontinued operations (Note 2(J))	0.05	(0.06)	(0.40)
Cumulative effect of accounting changes (Note 2(K))	(0.09)	–	0.33
Net Income	$ 2.62	$ 2.68	$ 1.39
WEIGHTED AVERAGE NUMBER OF BASIC SHARES OUTSTANDING	328	327	304
DILUTED EARNINGS PER SHARE OF COMMON STOCK:			
Income before discontinued operations and cumulative effect of accounting changes	$ 2.65	$ 2.73	$ 1.46
Discontinued operations (Note 2(J))	0.05	(0.06)	(0.40)
Cumulative effect of accounting changes (Note 2(K))	(0.09)	–	0.33
Net income	$ 2.61	$ 2.67	$ 1.39
WEIGHTED AVERAGE NUMBER OF DILUTED SHARES OUTSTANDING	330	329	305

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

Consolidated Balance Sheets

(In millions)

As of December 31,	2005	2004
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 64	$ 53
Receivables -		
Customers (less accumulated provisions of $38 million and $34 million, respectively, for uncollectible accounts)	1,293	979
Other (less accumulated provisions of $27 million and $26 million, respectively, for uncollectible accounts)	205	377
Materials and supplies, at average cost -		
Owned	518	364
Under consignment	–	94
Prepayments and other	237	145
	2,317	2,012
PROPERTY, PLANT AND EQUIPMENT:		
In service	22,893	22,213
Less - Accumulated provision for depreciation	9,792	9,413
	13,101	12,800
Construction work in progress	897	679
	13,998	13,479
INVESTMENTS:		
Nuclear plant decommissioning trusts	1,752	1,583
Investment in lease obligation bonds (Note 6)	890	951
Other	765	740
	3,407	3,274
DEFERRED CHARGES:		
Goodwill	6,010	6,050
Regulatory assets	4,486	5,499
Prepaid pension costs	1,023	–
Other	600	721
	12,119	12,270
	$31,841	$31,035
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Currently payable long-term debt	$ 2,043	$ 941
Short-term borrowings (Note 13)	731	170
Accounts payable	727	611
Accrued taxes	800	657
Other	1,152	929
	5,453	3,308
CAPITALIZATION (See Consolidated Statements of Capitalization):		
Common stockholders' equity	9,188	8,590
Preferred stock of consolidated subsidiaries not subject to mandatory redemption	184	335
Long-term debt and other long-term obligations	8,155	10,013
	17,527	18,938
NONCURRENT LIABILITIES:		
Accumulated deferred income taxes	2,726	2,324
Asset retirement obligations	1,126	1,078
Power purchase contract loss liability	1,226	2,001
Retirement benefits	1,316	1,239
Lease market valuation liability	851	936
Other	1,616	1,211
	8,861	8,789
COMMITMENTS, GUARANTEES AND CONTINGENCIES (Notes 6 and 14)		
	$31,841	$31,035

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

Consolidated Statements of Capitalization

(Dollars in millions, except per share amounts)

As of December 31,					2005	2004
COMMON STOCKHOLDERS' EQUITY:						
Common stock, $0.10 par value -authorized 375,000,000 shares-329,836,276 shares outstanding					$ 33	$ 33
Other paid-in capital					7,043	7,056
Accumulated other comprehensive loss (Note 2(I))					(20)	(313)
Retained earnings (Note 11(A))					2,159	1,857
Unallocated employee stock ownership plan common stock- 1,444,796 and 2,032,800 shares, respectively (Note 4(B))					(27)	(43)
Total common stockholders' equity					9,188	8,590
	Number of Shares Outstanding (Thousands)		Optional Redemption Price			
	2005	2004	Per Share	Aggregate		
PREFERRED STOCK OF CONSOLIDATED SUBSIDIARIES NOT SUBJECT TO MANDATORY REDEMPTION (Note 11(B)):						
Ohio Edison Company						
Cumulative, $100 par value- Authorized 6,000,000 shares						
3.90%	153	153	$103.63	$16	15	15
4.40%	176	176	108.00	19	18	18
4.44%	137	137	103.50	14	14	14
4.56%	144	144	103.38	15	14	14
Total	610	610		64	61	61
Pennsylvania Power Company						
Cumulative, $100 par value- Authorized 1,200,000 shares						
4.24%	40	40	103.13	4	4	4
4.25%	41	41	105.00	4	4	4
4.64%	60	60	102.98	6	6	6
7.75%	–	250		–	–	25
Total	141	391		14	14	39
Cleveland Electric Illuminating Company						
Cumulative, without par value- Authorized 4,000,000 shares						
$ 7.40 Series A	–	500		–	–	50
Adjustable Series L	–	474		–	–	46
Total	–	974		–	–	96
Toledo Edison Company						
Cumulative, $100 par value- Authorized 3,000,000 shares						
$ 4.25	160	160	104.63	17	16	16
$ 4.56	50	50	101.00	5	5	5
$ 4.25	100	100	102.00	10	10	10
	310	310		32	31	31
Cumulative, $25 par value- Authorized 12,000,000 shares						
$2.365	1,400	1,400	27.75	39	35	35
Adjustable Series A	–	1,200	–	–	–	30
Adjustable Series B	1,200	1,200	25.00	30	30	30
	2,600	3,800		69	65	95
Total	2,910	4,110		101	96	126
Jersey Central Power & Light Company						
Cumulative, $100 stated value- Authorized 15,600,000 shares						
4.00% Series	125	125	106.50	13	13	13

Consolidated Statements of Capitalization (Cont'd)

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

(In millions)

	First Mortage Bonds			Secured Notes			Unsecured Notes			Total	
As of December 31,		**2005**	**2004**		**2005**	**2004**		**2005**	**2004**	**2005**	**2004**
Ohio Edison Co.-											
Due 2005-2010	–	$ –	$ 80	4.00%	$ 113	$ 169	4.68%	$331	$361		
Due 2011-2015	–	–	–	3.35%	19	59	5.45%	150	150		
Due 2016-2020	–	–	–	5.45%	108	108	–	–	–		
Due 2026-2030	–	–	–	3.47%	180	180	–	–	–		
Due 2031-2035	–	–	–	3.58%	205	249	–	–	–		
Total-Ohio Edison		–	80		625	765		481	511	$1,106	$1,356
Cleveland Electric Illuminating Co.-											
Due 2005-2010	6.86%	125	125	6.23%	399	401	5.31%	28	28		
Due 2011-2015	–	–	–	3.15%	40	40	5.72%	379	378		
Due 2016-2020	–	–	–	6.72%	506	506	–	–	–		
Due 2021-2025	–	–	–	–	–	143	–	–	–		
Due 2026-2030	–	–	–	3.93%	29	29	–	–	–		
Due 2031-2035	–	–	–	3.66%	219	76	9.00%	103	103		
Total-Cleveland Electric		125	125		1,193	1,195		510	509	1,828	1,829
Toledo Edison Co.-											
Due 2005-2010	–	–	–	7.13%	30	30	5.21%	54	91		
Due 2016-2020	–	–	–	–	–	99	–	–	–		
Due 2021-2025	–	–	–	3.26%	67	67	–	–	–		
Due 2026-2030	–	–	–	5.90%	14	14	–	–	–		
Due 2031-2035	–	–	–	3.57%	127	82	–	–	–		
Total-Toledo Edison		–	–		238	292		54	91	292	383
Pennsylvania Power Co.-											
Due 2005-2010	9.74%	5	6	5.55%	54	10	3.50%	15	15		
Due 2011-2015	9.74%	5	5	5.40%	1	1	–	–	–		
Due 2016-2020	9.74%	4	4	4.27%	28	45	–	–	–		
Due 2021-2025	7.63%	6	6	3.60%	10	28	–	–	–		
Due 2026-2030	–	–	–	5.44%	9	23	–	–	–		
Due 2031-2035	–	–	–	–	–	5	–	–	–		
Total-Penn Power		20	21		102	112		15	15	137	148
Jersey Central Power & Light Co.-											
Due 2005-2010	6.85%	40	46	5.88%	245	261	–	–	–		
Due 2011-2015	7.10%	12	12	5.96%	125	125	–	–	–		
Due 2016-2020	–	–	–	5.42%	494	495	–	–	–		
Due 2021-2025	7.09%	275	325	–	–	–	–	–	–		
Total-Jersey Central		327	383		864	881		–	–	1,191	1,264
Metropolitan Edison Co.-											
Due 2005-2010	–	–	38	–	–	–	5.25%	250	250		
Due 2011-2015	–	–	–	–	–	–	4.90%	400	400		
Due 2021-2025	–	–	28	–	–	–	3.25%	28	–		
Due 2026-2030	5.95%	14	14	–	–	–	–	–	–		
Total-Metropolitan Edison		14	80	–	–			678	650	692	730
Pennsylvania Electric Co.-											
Due 2005-2010	5.35%	24	28	–	–	–	6.55%	135	143		
Due 2011-2015	–	–	–	–	–	–	5.13%	150	150		
Due 2016-2020	–	–	20	–	–	–	6.16%	145	125		
Due 2021-2025	–	–	25	–	–	–	3.19%	25	–		
Total-Pennsylvania Electric		24	73		–	–		455	418	479	491

Consolidated Statements of Capitalization (Cont'd)

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

(In millions)

	First Mortage Bonds			Secured Notes			Unsecured Notes			Total	
As of December 31,		**2005**	**2004**		**2005**	**2004**		**2005**	**2004**	**2005**	**2004**
FirstEnergy Corp.-											
Due 2005-2010	–	$ –	$ –	–	$ –	$ –	5.50%	$1,000	$1,515		
Due 2011-2015	–	–	–	–	–	–	6.45%	1,500	1,500		
Due 2031-2035	–	–	–	–	–	–	7.38%	1,500	1,500		
Total-FirstEnergy		–	–		–	–		4,000	4,515	$ 4,000	$ 4,515
Bay Shore Power		–	–	6.25%	134	138	–	–	–	134	138
Facilities Services Group		–	–	7.29%	4	7	–	–	–	4	7
FirstEnergy Generation		–	–	–	–	–	4.25%	58	15	58	15
FirstEnergy Nuclear Generation		–	–	–	–	–	4.17%	270	–	270	–
FirstEnergy Properties		–	–	7.89%	9	9	–	–	–	9	9
First Communications		–	–	–	–	–	–	–	5	–	5
Total		510	762		3,169	3,399		6,521	6,729	10,200	10,890
Preferred stock subject to mandatory redemption										–	17
Capital lease obligations										8	10
Net unamortized premium (discount) on debt										(10)	37
Long-term debt due within one year										(2,043)	(941)
Total long-term debt and other long-term obligations										8,155	10,013
TOTAL CAPITALIZATION										$17,527	$18,938

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

Consolidated Statements of Common Stockholders' Equity

(Dollars in millions)

	Comprehensive Income	Number of Shares	Par Value	Other Paid- In Capital	Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Unallocated ESOP Common Stock
Balance, January 1, 2003		297,636,276	$30	$6,120	$(656)	$1,635	$(78)
Net income	$ 423					423	
Minimum liability for unfunded retirement benefits, net of $102 million of income taxes	144				144		
Unrealized gain on investments, net of $53 million of income taxes	68				68		
Currency translation adjustments	91				91		
Comprehensive income	$ 726						
Stock options exercised				(3)			
Common stock issued		32,200,000	3	931			
Allocation of ESOP shares				15			20
Cash dividends declared on common stock						(453)	
Balance, December 31, 2003		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 taxes	(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 taxes	(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)

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

Consolidated Statements of Preferred Stock

(Dollars in millions)

	Not Subject to Mandatory Redemption		Subject to Mandatory Redemption*	
	Number of Shares	Par or Stated Value	Number of Shares	Par or Stated Value
Balance, January 1, 2003	6,209,699	$335	17,202,500	$430
Redemptions-				
7.625% Series			(7,500)	(1)
$7.35 Series C			(10,000)	(1)
8.56% Series			(5,000,000)	(125)
FIN 46 Deconsolidation-				
9.00% Series			(4,000,000)	(100)
7.35% Series			(4,000,000)	(92)
7.34% Series			(4,000,000)	(92)
Balance, December 31, 2003	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	–	$ –

** Preferred stock subject to mandatory redemption is classified as debt under SFAS 150.*

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

Consolidated Statements of Cash Flows

(Dollars in millions)

For the Years Ended December 31,	2005	2004	2003
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net Income	$861	$878	$423
Adjustments to reconcile net income to net cash from operating activities-			
Provision for depreciation	589	587	604
Amortization of regulatory assets	1,281	1,166	1,079
Deferral of new regulatory assets	(405)	(257)	(194)
Nuclear fuel and lease amortization	90	96	66
Deferred purchased power and other costs	(384)	(451)	(459)
Deferred income taxes and investment tax credits, net	154	258	(18)
Disallowed regulatory assets	–	–	153
Investment impairments (Note 2(H))	15	30	135
Cumulative effect of accounting changes	30	–	(102)
Deferred rents and lease market valuation liability	(104)	(84)	(119)
Revenue credits to customers	–	–	(72)
Accrued compensation and retirement benefits	90	156	202
Tax refund related to pre-merger period	18	–	51
Commodity derivative transactions, net	6	18	19
Loss (income) from discontinued operations (Note 2(J))	(18)	18	123
Cash collateral	196	(63)	(89)
Pension trust contribution	(500)	(500)	–
Decrease (increase) in operating assets-			
Receivables	(87)	154	66
Materials and supplies	(60)	(9)	5
Prepayments and other current assets	3	47	(31)
Increase (decrease) in operating liabilities-			
Accounts payable	32	(111)	(170)
Accrued taxes	154	(13)	222
Accrued interest	(6)	(42)	(60)
Electric service prepayment programs	208	(18)	(16)
NUG power contract restructuring	–	53	–
Other	57	(21)	(41)
Net cash provided from operating activities	2,220	1,892	1,777
CASH FLOWS FROM FINANCING ACTIVITIES:			
New Financing-			
Common Stock	–	–	934
Long-term debt	721	961	1,027
Short-term borrowings, net	561	–	–
Redemptions and Repayments-			
Preferred stock	(170)	(2)	(127)
Long-term debt	(1,424)	(1,572)	(2,129)
Short-term borrowings, net	–	(351)	(575)
Net controlled disbursement activity	(18)	(2)	25
Common stock dividend payments	(546)	(491)	(453)
Net cash used for financing activities	(876)	(1,457)	(1,298)
CASH FLOWS FROM INVESTING ACTIVITIES:			
Property additions	(1,208)	(846)	(856)
Proceeds from asset sales	61	214	79
Proceeds from certificates of deposit	–	278	–
Nonutility generation trusts withdrawals (contributions)	–	(51)	66
Contributions to nuclear decommissioning trusts	(101)	(101)	(101)
Long-term note receivable	–	–	82
Cash investments (Note 5)	36	27	53
Other	(121)	(17)	86
Net cash used for investing activities	(1,333)	(496)	(591)
Net increase (decrease) in cash and cash equivalents	11	(61)	(112)
Cash and cash equivalents at beginning of year	53	114	226
Cash and cash equivalents at end of year	$ 64	$ 53	$114
SUPPLEMENTAL CASH FLOW INFORMATION:			
Cash Paid During the Year-			
Interest (net of amounts capitalized)	$665	$704	$730
Income taxes	$406	$512	$162

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

Consolidated Statements of Taxes

(Dollars in millions)

For the Years Ended December 31,	2005	2004	2003
GENERAL TAXES:			
Kilowatt-hour excise*	$ 244	$ 236	$ 228
State gross receipts*	151	140	130
Real and personal property	222	208	184
Social security and unemployment	79	76	68
Other	17	18	28
Total general taxes	$ 713	$ 678	$ 638
PROVISION FOR INCOME TAXES:			
Currently payable-			
Federal	$ 456	$ 283	$ 309
State	143	133	118
Foreign	–	–	(1)
	599	416	426
Deferred, net-			
Federal	72	245	16
State	110	39	(8)
	182	284	8
Investment tax credit amortization	(27)	(27)	(26)
Total provision for income taxes	$ 754	$ 673	$ 408
RECONCILIATION OF FEDERAL INCOME TAX EXPENSE AT STATUTORY RATE TO TOTAL PROVISION FOR INCOME TAXES:			
Book income before provision for income taxes	$1,627	$1,569	$ 852
Federal income tax expense at statutory rate	$569	$549	$ 298
Increases (reductions) in taxes resulting from-			
Amortization of investment tax credits	(27)	(27)	(26)
State income taxes, net of federal income tax benefit	165	111	72
Penalties	14	–	–
Amortization of tax regulatory assets	38	33	32
Preferred stock dividends	5	8	7
Reserve for foreign operations	–	–	44
Other, net	(10)	(1)	(19)
Total provision for income taxes	$ 754	$ 673	$ 408
ACCUMULATED DEFERRED INCOME TAXES AS OF DECEMBER 31:			
Property basis differences	$2,368	$2,348	$2,180
Regulatory transition charge	537	785	1,085
Customer receivables for future income taxes	131	103	139
Shopping credit incentive deferral	321	252	153
Deferred sale and leaseback costs	(86)	(92)	(95)
Nonutility generation costs	(177)	(174)	(221)
Unamortized investment tax credits	(54)	(61)	(70)
Other comprehensive income	(18)	(219)	(244)
Retirement benefits	(135)	(280)	(445)
Lease market valuation liability	(361)	(420)	(455)
Oyster Creek securitization (Note 11(D))	173	184	193
Loss carryforwards	(417)	(463)	(495)
Loss carryforward valuation reserve	402	420	471
Asset retirement obligations	65	71	64
Deferred nuclear expenses	(105)	(100)	(65)
All other	82	(30)	(17)
Net deferred income tax liability	$2,726	$2,324	$2,178

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

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 subsidiary FGCO, NGC, FESC, FSG and MYR.

FirstEnergy and its subsidiaries follow GAAP and comply with the regulations, orders, policies and practices prescribed by the SEC, FERC and, as applicable, 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 2005 have been classified as discontinued operations on the Consolidated Statements of Income (see Note 2(J)). As discussed in Note 16, segment reporting in 2004 and 2003 was reclassified to conform to the 2005 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 SFAS 71 no longer meets those requirements, previously recorded regulatory assets are removed from the balance sheet in accordance with the guidance in SFAS 101.

In Ohio, 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. Regulatory assets that do not earn a current return totaled approximately $255 million as of December 31, 2005.

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

	2005	2004
	(In millions)	
Regulatory transition costs	$3,576	$4,889
Customer shopping incentives	884	612
Customer receivables for future income taxes	217	246
Societal benefits charge	29	51
Loss on reacquired debt	41	56
Employee postretirement benefit costs	55	65
Nuclear decommissioning, decontamination and spent fuel disposal costs	(126)	(169)
Asset removal costs	(365)	(340)
Property losses and unrecovered plant costs	29	50
MISO transmission costs	91	–
JCP&L reliability costs	23	–
Other	32	39
Total	$4,486	$5,499

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; and then by writing off any remaining regulatory transition costs and Extended RTC balances. In addition, the RCP allowed 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. See Note 10 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 will be equal to the related revenue recovery that is recognized. The following table provides the estimated net amortization of regulatory transition costs and Extended RTCs (including associated carrying charges) under the RCP for the period 2006 through 2010:

Amortization Period	OE	CEI	TE	Total Ohio
		(In millions)		
2006	$169	$100	$ 80	$ 349
2007	176	111	89	376
2008	198	129	100	427
2009	–	216	–	216
2010	–	268	–	268
Total Amortization	$543	$824	$269	$1,636

Regulatory transition costs as of December 31, 2005 for JCP&L and Met-Ed are approximately $2.2 billion and $308 million, respectively. Deferral of above-market costs from power supplied by NUGs to JCP&L are approximately $1.2 billion and are being recovered through BGS and MTC revenues. Met-Ed has deferred above-market NUG costs totaling approximately $143 million. These costs are being recovered through CTC revenues. The liability for 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 estimated weather impacts, customer shopping activity, historical line loss factors and prices in effect for each class of customer. In each accounting period, the Companies accrue the estimated unbilled amount receivable as revenue and reverse the related prior period estimate.

Receivables from customers include sales to residential, commercial and industrial customers and sales to wholesale customers. There was no material concentration of receivables as of December 31, 2005 with respect to any particular segment of FirstEnergy's customers. Total customer receivables were $1.3 billion (billed – $841 million and unbilled – $452 million) and $979 million (billed – $672 million and unbilled – $307 million) as of December 31, 2005 and 2004, 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 and $617 million in 2004 and 2003, respectively.

(E) EARNINGS PER SHARE OF COMMON STOCK

Basic earnings per share of common stock are computed using the weighted average of actual common shares outstanding during the respective period as the denominator. The denominator for diluted earnings per share 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. In 2004 and 2003, stock-based awards to purchase shares of common stock totaling 0.1 million and 3.3 million, respectively, were excluded from the calculation of diluted earnings per share of common stock because their exercise prices were greater than the average market price of common shares during the period. No stock-based awards were excluded from the calculation in 2005. The following table reconciles the denominators for basic and diluted earnings per share of common stock from Income Before Discontinued Operations and Cumulative Effect of Accounting Changes:

Reconciliation of Basic and Diluted Earnings per Share of Common Stock	2005	2004	2003
	(In millions, except per share amounts)		
Income Before Discontinued Operations and Cumulative Effect of Accounting Changes	$ 873	$ 896	$ 444
Average Shares of Common Stock Outstanding:			
Denominator for basic earnings per share (weighted average shares outstanding)	328	327	304
Assumed exercise of dilutive stock options and awards	2	2	1
Denominator for diluted earnings per share	330	329	305
Income Before Discontinued Operations and Cumulative Effect of Accounting Changes, per common share:			
Basic	$2.66	$2.74	$1.46
Diluted	$2.65	$2.73	$1.46

(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.

The Companies provide for depreciation on a straight-line basis at various rates over the estimated lives of property included in plant in service. The respective annual composite rates for the Companies' electric plant in 2005, 2004 and 2003 are shown in the following table:

Annual Composite Depreciation Rate	2005	2004	2003
OE	2.1%	2.3%	2.2%
CEI	2.9	2.8	2.8
TE	3.1	2.8	2.8
Penn	2.4	2.2	2.2
JCP&L	2.2	2.1	2.8
Met-Ed	2.4	2.4	2.6
Penelec	2.6	2.5	2.7

In October 2005, the Ohio Companies' and Penn's non-nuclear generation assets were transferred to FGCO and in December 2005, the Ohio Companies' and Penn's nuclear generation assets were transferred to NGC. FGCO and NGC provide for depreciation on a straight-line basis at various rates over the estimated lives of property included in plant in service.

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, 2005. 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 applies the recognition and measurement principles of APB 25 and related Interpretations in accounting for its stock-based compensation plans (see Note 4). No material stock-based employee compensation expense for options is reflected in net income as all options granted under those plans had an exercise price equal to the market value of the underlying common stock on the grant date, resulting in substantially no intrinsic value. FirstEnergy will apply the recognition and measurement principles of SFAS 123(R) effective January 1, 2006 (see Note 17).

(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 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, $12 million was reported as an operating expense and $24 million was included in the results from discontinued operations. FSG's fair value was estimated using current market valuations.

FirstEnergy's 2003 annual review resulted in a goodwill impairment charge of $122 million in the third quarter of 2003, reducing the carrying value of FSG. Of that amount, $91 million is reported as an operating expense and $31 million is included in the results from discontinued operations. The impairment charge reflected the slow down in the development of competitive retail markets and depressed economic conditions that affected the value of FSG. The fair value of FSG was estimated using primarily its expected discounted future cash flows.

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, 2005, FirstEnergy adjusted goodwill related to the divestiture of non-core operations (FES' retail natural gas business, MYR's Power Piping Company subsidiary, and a portion of its interest in FirstCom) as further discussed in Note 8. In addition, adjustments to the former GPU and Centerior companies' goodwill were recorded to reverse pre-merger tax accruals due to final resolution of these tax contingencies. 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, 2005 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, 2003	$5,993	$24	$196	$65	$6,278
Impairment charges			(122)		(122)
FSG divestitures			(41)		(41)
Other			3	10	13
Balance as of December 31, 2003	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

Investments

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

(I) COMPREHENSIVE INCOME

Comprehensive income includes net income as reported on the Consolidated Statements of Income and all other changes in common stockholders' equity except those resulting from transactions with common stockholders. As of December 31, 2005, AOCL consisted of a minimum liability for unfunded retirement benefits on non-qualified plans of $17 million, unrealized gains on investments in securities available for sale of $74 million and unrealized losses on derivative instrument hedges of $77 million. A summary of the changes in FirstEnergy's AOCL balance for the three years ended December 31, 2005 is shown below:

	2005	2004	2003
		(In millions)	
AOCL balance as of January 1,	$(313)	$(353)	$(656)
Minimum liability for unfunded retirement benefits	503	(11)	246
Unrealized gain (loss) on available for sale securities	(31)	46	119
Unrealized gain (loss) on derivative hedges	23	29	2
Currency translation adjustments	–	–	91
Other comprehensive income	495	64	458
Income taxes related to OCI	202	24	155
Other comprehensive income, net of tax	293	40	303
AOCL balance as of December 31,	$ (20)	$(313)	$(353)

Other comprehensive income reclassified to net income in 2005, 2004 and 2003 totaled $52 million, $8 million and $29 million, respectively. These amounts were net of income taxes in 2005, 2004 and 2003 of $35 million, $6 million and $20 million, respectively.

(J) ASSETS HELD FOR SALE AND DISCONTINUED OPERATIONS

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 continue to qualify as assets held for sale in accordance with SFAS 144. Management anticipates that the transfer of FSG assets, with a carrying value of $100 million as of December 31, 2005 will qualify for recognition as completed sales within one year. The FSG facilities which were deemed held for sale as of December 31, 2004 continue to be actively marketed as of December 31, 2005 and meet the criteria under SFAS 144 to continue to qualify as held for sale. As of December 31, 2005, the FSG subsidiaries classified as held for sale did not meet the criteria for discontinued operations. The carrying amounts of FSG's assets and liabilities held for sale are not material and have not been classified as assets held for sale on FirstEnergy's Consolidated Balance Sheet. See Note 16 for FSG's segment financial information.

In December 2005, MYR qualified as an asset held for sale but did not meet the criteria to be classified as a discontinued operation. Management anticipates that the transfer of MYR assets, with a carrying value of $226 million as of December 31, 2005, will qualify for recognition as completed sales within one year. 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 held for sale are not material and have not been classified as assets held for sale on FirstEnergy's Consolidated Balance Sheet. See Note 16 for MYR's segment financial information.

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.

The FSG subsidiaries, Colonial Mechanical, Webb Technologies and Ancoma, Inc., and MARBEL subsidiary, NEO, were sold in 2003. The financial results for these divested businesses included in discontinued operations totaled a loss of $4 million for the year ended December 31, 2003 and are included in "FSG and MYR subsidiaries" and "Other" in the table below.

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

In April 2003, FirstEnergy divested its ownership in Emdersa through the abandonment of its shares in Emdersa's parent company, GPU Argentina Holdings, Inc. The abandonment was accomplished by relinquishing FirstEnergy's shares to the independent Board of Directors of GPU Argentina Holdings, relieving FirstEnergy of all rights and obligations relative to this business. FirstEnergy included in discontinued operations Emdersa's operating income of $7 million and a $67 million charge for the abandonment in the second quarter of 2003 (no income tax benefit was recognized).

Revenues associated with discontinued operations were $206 million, $690 million and $819 million in 2005, 2004 and 2003, 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, 2005:

	2005	2004	2003
		(In millions)	
FES natural gas business	$ 5	$ 4	$ (2)
EGSA	–	–	(35)
Emdersa	–	–	(60)
FSG and MYR subsidiaries	13	(22)	(25)
Other	–	–	(1)
Income (loss) from discontinued operations	$18	$(18)	$(123)

(K) CUMULATIVE EFFECT OF ACCOUNTING CHANGES

Results in 2005 include 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 the new standard 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 share) for the year ended December 31, 2005. (See Note 12.)

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

(L) INCOME TAXES

Details of the total provision for income taxes are shown on the Consolidated Statements of Taxes. FirstEnergy records income taxes in accordance with the liability method of accounting. Deferred income taxes reflect the net tax effect of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and loss carry-forwards 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. (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. Since reserves have been recorded, final settlements of these audits are not expected to have a material adverse effect on FirstEnergy's financial condition or result of operations.

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 ($354 million) are fully offset by a valuation allowance as of December 31, 2005, 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 2005 the valuation allowance was reduced by $13 million due to the utilization of capital loss carryforwards to offset realized capital gains, resulting in an adjustment to goodwill.

Valuation allowances also include $48 million for deferred tax assets associated with impairment losses related to certain domestic assets.

FirstEnergy has net operating loss carry forwards for state and local income tax purposes of approximately $766 million. The associated deferred tax assets are $15 million. These losses expire as follows:

Expiration Period	Amount
	(In millions)
2006-2010	$277
2011-2015	34
2016-2020	178
2021-2024	277
	$766

3. PENSION AND OTHER POSTRETIREMENT BENEFIT PLANS

FirstEnergy provides noncontributory defined benefit pension plans that cover substantially all of its employees. The trusted plans provide defined benefits based on years of service and compensation levels. The Company's funding policy is based on actuarial computations using the projected unit credit method. In the fourth quarter of 2005, FirstEnergy made a $500 million voluntary cash contribution to its qualified pension plan. Projections indicated that absent this funding, cash contributions would have been required at some point prior to 2010. Pre-funding the pension plan is expected to eliminate this future funding requirement under current pension funding rules and should also minimize FirstEnergy's exposure to any funding requirements resulting from proposed pension reform.

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. 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 most of its plans.

Obligations and Funded Status As of December 31

	Pension Benefits		Other Benefits	
	2005	2004	2005	2004
	(In millions)			
Change in benefit obligation				
Benefit obligation as of January 1	$4,364	$4,162	$ 1,930	$ 2,368
Service cost	77	77	40	36
Interest cost	254	252	111	112
Plan participants' contributions	–	–	18	14
Plan amendments	15	–	(312)	(281)
Actuarial (gain) loss	310	134	197	(211)
Benefits paid	(270)	(261)	(100)	(108)
Benefit obligation as of December 31	$4,750	$4,364	$ 1,884	$ 1,930
Change in fair value of plan assets				
Fair value of plan assets as of January 1	$3,969	$3,315	$ 564	$ 537
Actual return on plan assets	325	415	33	57
Company contribution	500	500	58	64
Plan participants' contribution	–	–	18	14
Benefits paid	(270)	(261)	(100)	(108)
Fair value of plan assets as of December 31	$4,524	$3,969	$ 573	$ 564
Funded status	$ (226)	$ (395)	$(1,311)	$(1,366)
Unrecognized net actuarial loss	1,179	885	899	730
Unrecognized prior service cost (benefit)	70	63	(645)	(378)
Net asset (liability) recognized	$1,023	$ 553	$(1,057)	$(1,014)
Amounts Recognized in the Consolidated Balance Sheets As of December 31				
Prepaid benefit cost	$1,023	$ –	$ –	$ –
Accrued benefit cost	–	(14)	(1,057)	(1,014)
Intangible assets	–	63	–	–
Accumulated other comprehensive loss	–	504	–	–
Net amount recognized	$1,023	$ 553	$(1,057)	$(1,014)
Decrease in minimum liability included in other comprehensive income (net of tax)	$ (295)	$ (4)	–	–
Assumptions Used to Determine Benefit Obligations As of December 31				
Discount rate	5.75%	6.00%	5.75%	6.00%
Rate of compensation increase	3.50%	3.50%		
Allocation of Plan Assets As of December 31				
Asset Category				
Equity securities	63%	68%	71%	74%
Debt securities	33	29	27	25
Real estate	2	2	–	–
Cash	2	1	2	1
Total	100%	100%	100%	100%

Information for Pension Plans With an Accumulated Benefit Obligation in Excess of Plan Assets	2005	2004
	(In millions)	
Projected benefit obligation	$4,750	$4,364
Accumulated benefit obligation	4,327	3,983
Fair value of plan assets	4,524	3,969

Components of Net Periodic Benefit Costs

	Pension Benefits			Other Benefits		
	2005	2004	2003	2005	2004	2003
	(In millions)					
Service cost	$77	$77	$ 66	$ 40	$ 36	$ 43
Interest cost	254	252	253	111	112	137
Expected return on plan assets	(345)	(286)	(248)	(45)	(44)	(43)
Amortization of prior service cost	8	9	9	(45)	(40)	(9)
Amortization of transition obligation	–	–	–	–	–	9
Recognized net actuarial loss	36	39	62	40	39	40
Net periodic cost	$30	$91	$142	$101	$103	$177

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

	Pension Benefits			Other Benefits		
	2005	2004	2003	2005	2004	2003
Discount rate	6.00%	6.25%	6.75%	6.00%	6.25%	6.75%
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	2005	2004
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)	2010-2012	2009-2011

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

	1-Percentage-Point Increase	1-Percentage-Point Decrease
	(In millions)	
Effect on total of service and interest cost	$23	$(19)
Effect on accumulated postretirement benefit obligation	$239	$(209)

As a result of its voluntary contribution and the increased market value of pension plan assets, FirstEnergy recognized a prepaid benefit cost of $1 billion as of December 31, 2005. As prescribed by SFAS 87, FirstEnergy eliminated its additional minimum liability of $567 million and its intangible asset of $63 million. In addition, the entire AOCL balance was credited by $295 million (net of $208 million of deferred taxes) as the fair value of trust assets exceeded the accumulated benefit obligation as of December 31, 2005.

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

	Pension Benefits	Other Benefits
	(In millions)	
2006	$228	$106
2007	228	109
2008	236	112
2009	247	115
2010	264	119
Years 2011- 2015	1,531	642

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 $16 million for the year ended 2005 and $14 million for the years ended 2004 and 2003. The projected benefit obligation and the unfunded status was $161 million and $139 million as of December 31, 2005 and 2004, respectively. The net liability recognized was $254 million and $222 million as of December 31, 2005 and 2004, 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 $7 million for each of the years ended 2006–2009, $8 million in year ended 2010 and $53 million for years ended 2011-2015.

4. STOCK-BASED COMPENSATION PLANS

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

(A) LTIP

FirstEnergy's LTIP includes 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, 2005, 3.9 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:

	2005	2004	2003*
Restricted common shares granted	356,200	62,370	
Weighted average market price	$41.52	$40.69	
Weighted average vesting period (years)	5.4	2.7	
Dividends restricted	Yes	Yes	

** No restricted stock was granted.*

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. Restricted stock units granted in 2005 were 477,920 with a weighted average vesting period of 3.32 years.

Compensation expense recognized for restricted stock and restricted stock units during 2005 approximated $10 million. Compensation expense recognized for restricted stock during 2004 and 2003 totaled $2 million in each year.

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, 2003	10,435,486	$28.95
(1,400,206 options exercisable)		26.07
Options granted	3,981,100	29.71
Options exercised	455,986	25.94
Options forfeited	311,731	29.09
Balance, December 31, 2003	13,648,869	29.27
(1,919,662 options exercisable)		29.67
Options granted	3,373,459	38.77
Options exercised	3,622,148	26.52
Options forfeited	167,425	32.58
Balance, December 31, 2004	13,232,755	32.40
(3,175,023 options exercisable)		29.07
Options 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 outstanding by plan and range of exercise price as of December 31, 2005 were as follows:

		Options Outstanding			Options Exercisable	
FE Program	Range of Exercise Prices	Shares	Weighted Avg. Exercise Price	Remaining Contractual Life	Shares	Weighted Avg. Exercise Price
FE plan	$19.31-$29.87	3,828,991	$29.13	6.4	2,114,691	$28.66
	$30.17-$39.46	4,912,141	$37.10	7.4	1,851,014	$35.84
GPU plan	$23.75-$35.92	122,818	$30.99	3.3	122,818	$30.99
MYR plan	$14.23	1,256	$14.23	3.8	1,256	$14.23
CE plan	$25.14	1,050	$25.14	1.2	1,050	$25.14
Total		8,866,256	$33.57	6.9	4,090,829	$31.97

There were no stock options granted in 2005. The weighted average fair value of options granted in 2004 and 2003 are estimated below using the Black-Scholes option-pricing model and the following assumptions:

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

Compensation expense for FirstEnergy stock options is based on intrinsic value, which equals any positive difference between FirstEnergy's common stock price on the option's grant date and the option's exercise price. The exercise prices of all stock options granted in 2004 and 2003 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	2003
	(In millions, except per share amounts)		
Net Income, as reported	$ 861	$ 878	$ 423
Add back compensation expense reported in net income, net of tax (based on APB 25)*	32	21	24
Deduct compensation expense based upon estimated fair value, net of tax*	(39)	(35)	(36)
Pro forma net income	$ 854	$ 864	$ 411
Earnings Per Share of Common Stock -			
Basic			
As Reported	$2.62	$2.68	$1.39
Pro Forma	$2.60	$2.64	$1.35
Diluted			
As Reported	$2.61	$2.67	$1.39
Pro Forma	$2.59	$2.63	$1.35

* *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 (see Note 17). As a result, all currently unvested stock options will vest by 2008. The Company expects the adoption of SFAS 123(R) will increase annual compensation expense (after-tax) by approximately $7 million, $2 million and $0.5 million in 2006, 2007 and 2008, respectively, or $0.02 per share in 2006 and less than $0.01 per share in 2007 and 2008.

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 2005, 2004 and 2003 totaled approximately $7 million, $5 million and $7 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 2005, 2004 and 2003, 588,004 shares, 864,151 shares and 1,069,318 shares, respectively, were allocated to employees with the corresponding expense recognized based on the shares allocated method. The fair value of 1,444,796 shares unallocated as of December 31, 2005 was approximately $71 million. Total ESOP-related compensation expense was calculated as follows:

	2005	2004	2003
		(In millions)	
Base compensation	$39	$32	$35
Dividends on common stock held by the ESOP and used to service debt	(10)	(9)	(9)
Net expense	$29	$23	$26

(C) EDCP

Under the EDCP, covered employees can direct a portion of their compensation, including annual incentive awards and/or long-term incentive awards, into an unfunded FirstEnergy stock account to receive vested stock units 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, 678,503 stock units were available for future awards as of December 31, 2005. Compensation expense recognized on EDCP stock units in 2005, 2004 and 2003 approximated $5 million, $2 million and $2 million, respectively.

(D) DCPD

Under the DCPD, directors can elect to allocate all or a portion of their cash retainers, meeting fees and chair fees to 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 2005, 2004 and 2003 were approximately $3 million, $4 million and $2 million, respectively. The net liability recognized was $5 million and $3 million as of December 31, 2005 and 2004, respectively, and is included in the caption "retirement benefits" on the Consolidated Balance Sheets.

5. FAIR VALUE OF FINANCIAL INSTRUMENTS

Long-term Debt and Other Long-term Obligations

All borrowings with initial maturities of less than one year are defined as 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 (including currently payable) as of December 31:

	2005		2004	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	(In millions)			
Long-term debt	$10,097	$10,576	$10,787	$11,341
Subordinated debentures to affiliated trusts	103	140	103	112
Preferred stock subject to mandatory redemption	–	–	17	16
	$10,200	$10,716	$10,907	$11,469

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

Investments

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

	2005		2004	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	(In millions)			
Debt securities:[1]				
– Government obligations	$ 893	$ 887	$ 797	$ 797
– Corporate debt securities[2]	1,137	1,248	1,205	1,362
– Mortgage-backed securities	–	–	2	2
	2,030	2,135	2,004	2,161
Equity securities[1]	1,129	1,130	1,033	1,033
	$3,159	$3,265	$3,037	$3,194

(1) *Includes nuclear decommissioning, nuclear fuel disposal and NUG trust investments.*

(2) *Includes investments in lease obligation bonds (see Note 6).*

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

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

	2005				2004			
	Cost Basis	Un-realized Gains	Un-realized Losses	Fair Value	Cost Basis	Un-realized Gains	Un-realized Losses	Fair Value
	(In millions)							
Debt securities	$ 681	$ 12	$ 7	$ 686	$ 616	$ 19	$ 3	$ 632
Equity securities	898	190	21	1,067	763	207	19	951
	$1,579	$202	$28	$1,753	$1,379	$226	$22	$1,583

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, 2005 were as follows:

	2005	2004	2003
	(In millions)		
Proceeds from sales	$1,419	$1,234	$758
Realized gains	133	144	38
Realized losses	58	43	32
Interest and dividend income	49	45	37

The following table provides the fair value of, and unrealized losses on, nuclear decommissioning trust investments that are deemed to be temporarily impaired as of December 31, 2005:

	Less Than 12 Months		12 Months or More		Total	
	Fair Value	Unrealized Losses	Fair Value	Unrealized Losses	Fair Value	Unrealized Losses
	(In millions)					
Debt securities	$276	$ 5	$ 81	$ 2	$357	$ 7
Equity securities	240	10	39	11	279	21
	$516	$15	$120	$13	$636	$28

The Companies and NGC periodically evaluate the securities held by their nuclear decommissioning trusts for other-than-temporary impairment. FirstEnergy considers the length of time and the extent to which the security's fair value has been less than its cost basis and other factors to determine whether impairment is other than temporary. Unrealized gains and losses applicable to 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.

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

Derivatives

FirstEnergy is exposed to financial risks resulting from the fluctuation of interest rates and commodity prices, including prices for electricity, natural gas, 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 criteria. Derivatives that meet the normal purchase and sales criteria 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 criteria 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 involves 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 operating expense, when the underlying hedged commodities are delivered or interest payments are made. AOCL as of December 31, 2005 includes a net deferred loss of $78 million for derivative hedging activity. The $14 million decrease from the December 31, 2004 balance of $92 million includes $2 million reduction related to current hedging activity and a $12 million decrease due to net hedge losses included in earnings during the year. Approximately $17 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 2005 and 2004 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 2005, a $24 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 2005, FirstEnergy entered into interest rate swap agreements on $150 million notional amount of senior notes with a weighted average fixed interest rate of 6.59%. In addition, FirstEnergy unwound swaps with a total notional amount of $700 million from which it received $16 million in cash gains during 2005. The gains will be recognized over the remaining maturity of each respective hedged security as reduced interest expense. As of December 31, 2005, the aggregate notional value of interest rate swap agreements outstanding was $1.1 billion.

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, 2005, FirstEnergy had entered into forward swaps with an aggregate notional amount of $975 million. As of December 31, 2005, the forward swaps had a fair value of $3 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, 2005 are summarized as follows:

	2005	2004	2003
		(In millions)	
Operating leases			
Interest element	$171	$175	$184
Other	162	140	166
Capital leases			
Interest element	1	1	2
Other	2	3	2
Total rentals	$336	$319	$354

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, 2005 are:

	Capital Leases	Operating Leases: Lease Payments	Operating Leases: Capital Trusts	Operating Leases: Net
		(In millions)		
2006	$5	$ 344	$ 142	$ 202
2007	1	320	131	189
2008	1	313	105	208
2009	1	316	112	204
2010	1	316	121	195
Years thereafter	4	1,997	639	1,358
Total minimum lease payments	13	$3,606	$1,250	$2,356
Executory costs	2			
Net minimum lease payments	11			
Interest portion	3			
Present value of net minimum lease payments	8			
Less current portion	3			
Noncurrent portion	$5			

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, 2005, the above-market lease liabilities for Beaver Valley Unit 2 and the Bruce Mansfield Plant totaled $936 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 VIEs when they are 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 above in Note 6. PNBV and Shippingport financial data are included in the consolidated financial statements of OE and CEI, respectively.

PNBV was established to purchase a portion of the lease obligation bonds issued in connection with OE's 1987 sale and leaseback of its interests in the Perry Plant and Beaver Valley Unit 2. OE used debt and available funds to purchase the notes issued by PNBV. Ownership of PNBV includes a 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-leaseback agreements upon the occurrence of certain contingent events that each company considers unlikely to occur. OE, CEI and TE each have a maximum exposure to loss under these provisions of approximately $1 billion, which represents the net amount of casualty value payments upon the occurrence of specified casualty events that render the applicable plant worthless. Under the applicable sale and leaseback agreements, OE, CEI and TE have net minimum discounted lease payments of $652 million, $105 million and $539 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 recognizes a liability and a corresponding regulatory asset on its Consolidated Balance Sheets for the projected above-market costs related to its NUG agreements. As of December 31, 2005, the projected above-market loss liability recognized for these eight NUG agreements was $119 million. Purchased power costs from these entities during 2005, 2004 and 2003 were $180 million, $175 million and $167 million, respectively.

8. DIVESTITURES

Other Domestic Operations

In 2005, FirstEnergy sold three FSG subsidiaries - Pennsylvania-based Elliott-Lewis Corporation, Ohio-based Spectrum Control Systems, Inc. and Maryland-based L. H. Cranston and Sons, Inc. - and a MYR subsidiary - Power Piping Company, resulting in an aggregate after-tax gain of $13 million. All of these sales, with the exception of L.H. Cranston and Sons, Inc. met the discontinued operations criteria (see Note 2(J)). In 2003, FirstEnergy sold three additional FSG subsidiaries - Ancoma, Inc., a mechanical contracting company based in Rochester, New York, and Virginia-based Colonial Mechanical and Webb Technologies - and a MARBEL subsidiary - Northeast Ohio Natural Gas, for an aggregate after-tax gain of $3 million.

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.

Generation Assets

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

International Operations

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. In the fourth quarter of 2003, after-tax impairment charges reduced the carrying value of Avon ($5 million) and TEBSA ($26 million). As a result, no gain or loss was recognized upon the sales in 2004. Avon, TEBSA and other international assets sold in 2003 were originally acquired as part of FirstEnergy's November 2001 merger with GPU.

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

In 2003 FirstEnergy recognized an after-tax impairment of $8 million related to the carrying value of the note receivable from Aquila. After receiving the first annual installment payment of $19 million in May 2003, FirstEnergy sold the remaining balance of its note receivable in the secondary market and received $63 million in proceeds in July 2003.

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 will be computed consistent with the prior tax law, except that the tax liability as computed will be multiplied by 4/5 in 2005; 3/5 in 2006; 2/5 in 2007 and 1/5 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, 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 as the result of adoption of mandatory reliability standards pursuant to the EPACT that could require additional, material expenditures. Finally, the PUCO is continuing to review the FirstEnergy filing that addressed upgrades to control room computer hardware and software and enhancements to the training of control room operators before determining the next steps, if any, in the proceeding.

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 a Special Reliability Master 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). A final order in the Focused Audit docket was issued by the NJBPU on July 23, 2004. On February 11, 2005, JCP&L met with the Ratepayer Advocate to discuss reliability improvements. JCP&L continues to file compliance reports reflecting activities associated with the MOU and Stipulation.

In May 2004, the PPUC issued an order approving revised reliability benchmarks and standards, including revised benchmarks and standards for Met-Ed, Penelec and Penn. Met-Ed, Penelec and Penn filed a Petition for Amendment of Benchmarks with the PPUC on May 26, 2004, due to their implementation of automated outage management systems following restructuring. On December 30, 2005 the ALJ recommended that the PPUC adopt the Joint Petition for Settlement among the parties involved in the three Companies' request to amend the distribution reliability benchmarks, thereby eliminating the need for full litigation. The ALJ's recommendation, adopting the revised benchmarks and standards was approved by the PPUC on February 9, 2006.

The EPACT provides for the creation of an ERO to establish and enforce reliability standards for the bulk power system, subject to FERC review. On February 3, 2006, the FERC adopted a rule establishing certification requirements for the ERO, as well as regional entities envisioned to assume monitoring responsibility for the new reliability standards.

The NERC has been preparing the implementation aspects of reorganizing its structure to meet the FERC's certification requirements for the ERO. The NERC will make a filing with the FERC to obtain certification as the ERO and to obtain FERC approval of delegation agreements with regional entities. The new FERC rule referred to above, further provides for reorganizing regional reliability organizations (regional entities) that would replace the current regional councils and for rearranging the relationship with the ERO. The "regional entity" may be delegated authority by the ERO, subject to FERC approval, for enforcing reliability standards adopted by the

ERO and approved by the FERC. NERC also intends to make a parallel filing with the FERC seeking approval of mandatory reliability standards. These reliability standards are expected to be based on the current NERC Version 0 reliability standards with some additional standards. The two filings are expected to be made in the second quarter of 2006.

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

On a parallel path, the NERC is establishing working groups to develop reliability standards to be filed for approval with the FERC following the NERC's certification as an ERO. These reliability standards are expected to build on the current NERC Version 0 reliability standards. It is expected that the proposed reliability standards will be filed with the FERC in early 2006.

FirstEnergy believes it is in compliance with all current NERC reliability standards. However, it is expected that the FERC will adopt stricter reliability standards than those contained in the current NERC Version 0 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.

(B) OHIO

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 competitive bid process. The RSP was intended to establish generation service rates beginning January 1, 2006, in response to PUCO concerns about price and supply uncertainty following the end of the Ohio Companies' transition plan market development period. In October 2004, the OCC and NOAC filed appeals with the Supreme Court of Ohio to overturn the original June 9, 2004 PUCO order in this proceeding as well as the associated entries on rehearing. On September 28, 2005, the Ohio Supreme Court heard oral arguments on the appeals and it is expected that the Court will issue its opinion in 2006. On November 1, 2005, the Ohio Companies filed tariffs in compliance with the approved RSP, which were approved by the PUCO on December 7, 2005.

On May 27, 2005, the Ohio Companies filed an application with the PUCO to establish a GCAF rider under the RSP. The GCAF application sought recovery of increased fuel costs from 2006 through 2008 applicable to the Ohio Companies' retail customers through a tariff rider to be implemented January 1, 2006. The application reflected projected increases in fuel costs in 2006 compared to 2002 baseline costs. The new rider, after adjustments made in testimony, sought to recover all costs above the baseline (approximately $88 million in 2006). Various parties including the OCC intervened in this case and the case was consolidated with the RCP application discussed below.

On September 9, 2005, the Ohio Companies filed an application with the PUCO that supplemented their existing RSP with an RCP which was designed to provide customers with more certain rate levels than otherwise available under the RSP during the plan period. Major provisions of the RCP include:

- Maintain the existing level of base distribution rates through December 31, 2008 for OE and TE, and April 30, 2009 for CEI;
- Defer and capitalize for future recovery 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;
- Adjust 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 as of December 31, 2010 for CEI;
- Reduce 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
- Recover increased fuel costs 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 increased fuel costs above the amount collected through the fuel recovery mechanism (in lieu of implementation of the GCAF rider).

On November 4, 2005, a supplemental stipulation was filed with the PUCO which was in addition to a stipulation filed with the September 9, 2005 application. On January 4, 2006, the PUCO approved the RCP filing with modifications. On January 10, 2006, the Ohio Companies filed a Motion for Clarification of the PUCO order approving the RCP. The Ohio Companies sought clarity on issues related to distribution deferrals, including requirements of the review process, timing for recognizing certain deferrals and definitions of the types of qualified expenditures. The Ohio Companies also sought confirmation that the list of deferrable distribution expenditures originally included in the revised stipulation fall within the PUCO order definition of qualified expenditures. 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: 1) recognize fuel and distribution deferrals commencing January 1, 2006; 2) recognize distribution deferrals on a monthly basis prior to review by the PUCO Staff; 3) clarify that the types of distribution expenditures included in the Supplemental Stipulation may be deferred; and 4) clarify that distribution expenditures do not have to be "accelerated" in order to be deferred. The PUCO granted 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 Companies' Motion. On February 3, 2006, several other parties filed applications for rehearing on the PUCO's January 4, 2006 Order. The Ohio Companies responded to the application for rehearing on February 13, 2006.

Under provisions of the RSP, the PUCO may require the Ohio Companies to undertake, no more often than annually, a competitive bid process to secure generation for the years 2007 and 2008. On July 22, 2005, FirstEnergy filed a competitive bid process for the period beginning in 2007 that is similar to the competitive bid process approved by the PUCO for the Ohio Companies in 2004, which resulted in the PUCO accepting no bids. Any acceptance of future competitive bid results would terminate the RSP pricing, with no accounting impacts to the RSP, and not until twelve months after the PUCO authorizes such termination. On September 28, 2005, the PUCO issued an Entry that essentially approved the Ohio Companies' filing but delayed the proposed timing of the competitive bid process by four months, calling for the auction to be held on March 21, 2006. OCC filed an application for rehearing of the September 28, 2005 Entry, which the PUCO denied on November 22, 2005. On February 23, 2006, the auction manager notified the PUCO that there was insufficient interest in the auction process to allow it to proceed in 2006.

(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 October 2, 2003, the PPUC issued an order concluding that the Commonwealth Court reversed the PPUC's June 2001 order in its entirety. In accordance with the PPUC's direction, Met-Ed and Penelec filed supplements to their tariffs that became effective in October 2003 and that reflected the CTC rates and shopping credits in effect prior to the June 2001 order.

Met-Ed and Penelec had been negotiating with interested parties in an attempt to resolve the merger savings issues that are the subject of remand from the Commonwealth Court. Met-Ed's and Penelec's combined portion of total merger savings during 2001 – 2004 is estimated to be approximately $51 million. In late 2005, settlement discussions broke off as unsuccessful. A procedural schedule was established by the ALJ on January 17, 2006. The companies' initial testimony is due on March 1, 2006 with testimony of the other parties and additional testimony by the companies to be filed through October, 2006. Hearings are scheduled for the end of October 2006 with the ALJ's recommended decision to be issued in February, 2007. The companies are unable to predict the outcome of this proceeding.

In an October 16, 2003 order, the PPUC approved September 30, 2004 as the date for Met-Ed's and Penelec's NUG trust fund refunds. The PPUC order also denied their accounting treatment request regarding the CTC rate/shopping credit swap by requiring Met-Ed and Penelec to treat the stipulated CTC rates that were in effect from January 1, 2002 on a retroactive basis. On October 22, 2003, Met-Ed and Penelec filed an Objection with the Commonwealth Court asking that the Court reverse this PPUC finding; a Commonwealth Court judge subsequently denied their Objection on October 27, 2003 without explanation. On October 31, 2003, Met-Ed and Penelec filed an Application for Clarification of the Court order with the judge, a Petition for Review of the PPUC's October 2 and October 16, 2003 Orders, and an application for reargument, if the judge, in his clarification order, indicates that Met-Ed's and Penelec's Objection was intended to be denied on the merits. The Reargument Brief before the Commonwealth Court was filed on January 28, 2005.

As of December 31, 2005, 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 are $333 million and $48 million, respectively. Penelec's $48 million is subject to the pending resolution of taxable income issues associated with NUG Trust Fund proceeds.

Met-Ed and Penelec purchase a portion of their PLR requirements from FES through a wholesale power sales agreement and a portion from contracts with unaffiliated third party suppliers, including NUGs. Assuming continuation of these existing contractual arrangements, the available supply represents approximately 100% of the combined retail sales obligations of Met-Ed and Penelec in 2006 and 2007; almost 100% for 2008; and approximately 85% for 2009 and 2010. Met-Ed and Penelec are authorized to defer any excess of NUG contract costs over current market prices. Under the terms of the wholesale agreement with FES, FES retains the supply obligation and the supply profit and loss risk for the portion of power supply requirements not self-supplied by Met-Ed and Penelec under their contracts with NUGs and other unaffiliated suppliers. This arrangement reduces Met-Ed's and Penelec's exposure to high wholesale power prices by providing power at a fixed price for their uncommitted PLR energy costs during the term of the agreement with FES. The wholesale agreement with FES is automatically extended for each successive calendar year unless any party elects to cancel the agreement by November 1 of the preceding year. On November 1, 2005, FES and the other parties thereto amended the agreement to provide FES the right over the next year to terminate the agreement at any time upon 60 days notice. If the wholesale power agreement were terminated or modified, Met-Ed and Penelec would need to satisfy the portion of their PLR obligations currently supplied by FES from unaffiliated suppliers at prevailing prices, which are likely to be higher than the current price charged by FES under the agreement and, as a result, Met-Ed's and Penelec's purchased power costs could materially increase. If Met-Ed and Penelec were to replace the 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 support an investment grade rating for its fixed income securities. Met-Ed and Penelec are in the process of preparing a comprehensive rate filing that will address a number of transmission, distribution and supply issues and is expected to be filed with the PPUC in the second quarter of 2006. That filing will include, among other things, a request for appropriate regulatory action to mitigate adverse consequences from any future reduction, in whole or in part, in the availability to Met-Ed and Penelec of supply under the existing FES agreement. There can be no assurance, however, that if FES ultimately determines to terminate, or significantly modify the agreement, timely regulatory relief will be granted by the PPUC or, to the extent granted, adequate to mitigate such adverse consequences.

On October 11, 2005, Penn filed a plan with the PPUC to secure electricity supply for its customers at set rates following the end of its transition period on December 31, 2006. Penn is recommending that the RFP process cover the period January 1, 2007 through May 31, 2008. Hearings were held on January 10, 2006 with Main Briefs filed on January 27, 2006 and Reply Briefs on February 3, 2006. On February 17, 2006, the ALJ issued a Recommended Decision to adopt Penn's RFP process with modifications. A PPUC vote is expected in April 2006. Under Pennsylvania's electric competition law, Penn is required to secure generation supply for customers who do not choose alternative suppliers for their electricity.

(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 MTC rates and market sales of NUG energy and capacity. As of December 31, 2005, the accumulated deferred cost balance totaled approximately $541 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. JCP&L is in discussions with the NJBPU staff as a result of the stipulated settlement agreements (as further discussed below) which recommended that the NJBPU issue an order regarding JCP&L's application. On July 20, 2005, JCP&L requested the NJBPU to set a procedural schedule for this matter and is awaiting NJBPU action. On February 1, 2006, the NJBPU selected Bear Stearns as the financial advisor. On December 2, 2005, JCP&L filed a request for recovery of $165 million of actual above-market NUG costs incurred from August 1, 2005 through October 31, 2005 and forecasted above-market NUG costs for November and December 2005. The filing also includes a request for recovery of $49 million for above-market NUG costs incurred prior to August 1, 2003, to the extent those costs are not recoverable through securitization.

The 2003 NJBPU decision on JCP&L's base electric rate proceeding (the Phase I Order) disallowed certain regulatory assets and provided for an interim return on equity of 9.5% on JCP&L's rate base. The Phase I order also provided for a Phase II proceeding in which the NJBPU would review whether JCP&L is in compliance with current service reliability and quality standards and determine whether the expenditures and projects undertaken by JCP&L to increase its system's reliability are prudent and reasonable for rate recovery. Depending on its assessment of JCP&L's service reliability, the NJBPU could have increased JCP&L's return on equity to 9.75% or decreased it to 9.25%.

On July 16, 2004, JCP&L filed the Phase II petition and testimony with the NJBPU, requesting an increase in base rates of $36 million for the recovery of system reliability costs and a 9.75% return on equity. The filing also requested an increase to the MTC deferred balance recovery of approximately $20 million annually.

On May 25, 2005, the NJBPU approved two stipulated settlement agreements. The first stipulation between JCP&L and the NJBPU staff resolves all of the issues associated with JCP&L's motion for reconsideration of the Phase I Order. The second stipulation between JCP&L, the NJBPU staff and the Ratepayer Advocate resolves all of the issues associated with JCP&L's Phase II proceeding. The stipulated settlements provide for, among other things, the following:

- An annual increase in distribution revenues of $23 million effective June 1, 2005, associated with the Phase I Order reconsideration;
- An annual increase in distribution revenues of $36 million effective June 1, 2005, related to JCP&L's Phase II Petition;
- An annual reduction in both rates and amortization expense of $8 million, effective June 1, 2005, in anticipation of an NJBPU order regarding JCP&L's request to securitize up to $277 million of its deferred cost balance;
- An increase in JCP&L's authorized return on common equity from 9.5% to 9.75%; and
- A commitment by JCP&L, through December 31, 2006 or until related legislation is adopted, whichever occurs first, to maintain a target level of customer service reliability with a reduction in JCP&L's authorized return on common equity from 9.75% to 9.5% if the target is not met for two consecutive quarters. The authorized return on common equity would then be restored to 9.75% if the target is met for two consecutive quarters.

The Phase II stipulation included an agreement that the distribution revenue increase also reflects a three-year amortization of JCP&L's one-time service reliability improvement costs incurred in 2003-2005. This resulted in the creation of a regulatory asset associated with accelerated tree trimming and other reliability costs which were expensed in 2003 and 2004. The establishment of the new regulatory asset of approximately $28 million resulted in an increase to net income of approximately $16 million ($0.05 per share of common stock) in the second quarter of 2005.

JCP&L sells all self-supplied energy (NUGs and owned generation) to the wholesale market with offsetting credits to its deferred energy balance with the exception of 300 MW from JCP&L's NUG committed supply currently being used to serve BGS customers pursuant to NJBPU order for the period June 1, 2005 through May 31, 2006. New BGS tariffs reflecting the results of a February 2005 auction for the BGS supply became effective June 1, 2005.

The NJBPU decision approving the BGS procurement proposal for the period beginning June 1, 2006 was issued on October 12, 2005. JCP&L submitted a compliance filing on October 26, 2005, which was approved on November 10, 2005. The written Order was dated December 8, 2005. The auction took place in early February 2006 and the results have been approved by the NJBPU.

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 Ratepayer Advocate filed comments on February 28, 2005. On March 18, 2005, JCP&L filed a response to those comments. A schedule for further 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 recent repeal of PUHCA under the EPACT. An NJBPU proposed rulemaking to address the issues was published in the NJ Register on December 19, 2005. The proposal 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. A public hearing was held on February 7, 2006 and comments may be submitted to the NJBPU by February 17, 2006. JCP&L is not able to predict the outcome of this proceeding at this time.

(E) TRANSMISSION

On November 1, 2004, ATSI requested authority from the FERC to defer approximately $54 million of vegetation management costs estimated to be incurred from 2004 through 2007. On March 4, 2005, the FERC approved ATSI's request to defer those costs ($26 million deferred as of December 31, 2005). ATSI expects to file an application with the FERC in 2006 that would include recovery of the deferred costs beginning June 1, 2006.

On January 24, 2006, ATSI and MISO filed an application with the FERC to modify the Attachment O formula rate mechanism to permit ATSI to accelerate recovery of revenues lost due to the FERC's elimination of through and out rates between MISO and PJM, and the elimination of other ATSI rates in the MISO tariff. Revenues formerly collected under these rates are currently used to reduce the ATSI zonal transmission rate in the Attachment O formula. The revenue shortfall created by elimination of these rates would not be fully reflected in ATSI's formula rate until June 1, 2006, unless the proposed Revenue Credit Collection is approved by the FERC. The Revenue Credit Collection mechanism is designed to collect approximately $40 million in revenues on an annualized basis beginning June 1, 2006. FERC is expected to act on this filing on or before April 1, 2006.

ATSI, JCP&L, Met-Ed, Penelec, and FES continue to be involved in FERC hearings concerning the calculation and imposition of Seams Elimination Cost Adjustment (SECA) charges to various load serving entities. Pursuant to its January 30, 2006 Order, the FERC has compressed both phases of this proceeding into a single hearing scheduled to begin May 1, 2006, with an initial decision on or before August 11, 2006.

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 PUCO approved the settlement stipulation on August 31, 2005. The incremental transmission and ancillary service revenues expected to be recovered from January through June 2006 are approximately $66 million. This amount includes the recovery of the 2005 deferred MISO expenses as described below. In May 2006, the Companies will file a modification to the rider to determine revenues from July 2006 through June 2007.

The second application sought authority to defer costs associated with transmission and ancillary service related costs incurred during the period from 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. All briefs have been filed. A motion to dismiss filed on behalf of the PUCO is currently pending. Unless the court grants the motion, the appeal will be set for oral argument, which should be heard in the third or fourth quarter of 2006.

On January 20, 2006 the OCC sought rehearing of the PUCO approval of the rider recovery during the period January 1, 2006 through June 30, 2006, as that amount pertains to recovery of the deferred costs. The PUCO denied the OCC's application on February 6, 2006. The OCC has sixty days from that date to appeal the PUCO's approval of the rider.

On January 12, 2005, Met-Ed and Penelec filed, before the PPUC, a request for deferral of transmission-related costs beginning January 1, 2005, estimated to be approximately $8 million per month. The OCA, OSBA, OTS, MEIUG, PICA, Allegheny Electric Cooperative and Pennsylvania Rural Electric Association have all intervened in the case. To date, no hearing schedule has been established, and neither company has yet implemented deferral accounting for these costs.

On January 31, 2005, certain PJM transmission owners made three filings 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. Second, the FERC approved the proposed Schedule 12 rate harmonization. Third, the FERC accepted the proposed formula rate, subject to referral and hearing procedures. On June 30, 2005, the PJM transmission owners filed a request for rehearing of the May 31, 2005 order. The rate design and formula rate proceedings are currently being litigated before the FERC. If FERC accepts AEP's proposal to create a "postage stamp" rate for high voltage transmission facilities across PJM, significant additional transmission revenues would be imposed on JCP&L, Met-Ed, Penelec, and other transmission zones within PJM.

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 competitive bid process 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. Penn has filed a plan with the PPUC to use an RFP process to obtain its power supply requirements after 2006.

On December 29, 2005, the FERC issued an order setting the two power sales agreements for hearing. The order criticizes the Ohio competitive bid process, and requires FES to submit additional evidence in support of the reasonableness of the prices charged in the Ohio and Pennsylvania Contracts. A pre-hearing conference was held on January 18, 2006 to determine the hearing schedule in this case. FES expects an initial decision to be issued in this case in the fall of 2006. The outcome of this proceeding cannot be predicted. FES has sought rehearing of the December 29, 2005 order.

11. CAPITALIZATION

(A) COMMON STOCK

Retained Earnings and Dividends

Under applicable federal law, FirstEnergy and its subsidiaries can pay dividends only from retained or current earnings, unless the FERC specifically authorizes payment from other capital accounts. As of December 31, 2005, FirstEnergy's unrestricted retained earnings were $2.2 billion. 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, 2005, none of these provisions materially restricted FirstEnergy's subsidiaries ability to pay cash dividends to FirstEnergy.

On November 15, 2005, the Board of Directors increased the indicated annual dividend to $1.80 per share, payable quarterly at a rate of $0.45 per share beginning in the first quarter of 2006. 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 payable in the first quarter of 2006. Dividends declared in 2004 were $1.9125, which included quarterly dividends of $0.375 per share paid in each quarter of 2004 and an additional dividend of $.04125 paid in the first quarter of 2005. The amount and timing of all dividend declarations are subject to the discretion of the Board and its consideration of business conditions, results of operations, financial condition and other factors.

(B) PREFERRED AND PREFERENCE STOCK

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

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.

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

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

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

Subordinated Debentures to Affiliated Trusts

As of December 31, 2005, 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 are 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

JCP&L Transition (Issuer), a wholly owned limited liability company of JCP&L, sold $320 million of transition bonds to securitize the recovery of JCP&L's bondable stranded costs associated with the previously divested Oyster Creek Nuclear Generating Station. JCP&L did not purchase and does not own any of the transition bonds. As of December 31, 2005, $264 million of transition bonds are outstanding and included in long-term debt on FirstEnergy's Consolidated Balance Sheet. The transition bonds represent obligations only of the Issuer and are collateralized solely by the equity and assets of the Issuer, which consist primarily of bondable transition property. The bondable transition property is solely the property of the Issuer.

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

Other Long-term Debt

Each of the Companies has a first mortgage indenture under which it issues 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, 2005, the Companies' annual sinking fund requirement for all FMB issued under the various mortgage indentures amounts to $67 million. OE and Penn expect to deposit funds with their respective mortgage bond trustees in 2006 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)
2006	$2,040
2007	229
2008	463
2009	278
2010	204

Included in the table above are amounts for certain variable interest rate pollution control 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 $662 million, $132 million and $15 million in 2006, 2008 and 2010, respectively, representing the next times 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 $604 million at December 31, 2005 or noncancelable municipal bond insurance policies of $1.419 billion at December 31, 2005 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 0.65% to 1.70% of the amounts of the LOCs to the issuing banks and 0.16% to 0.60% 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

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

FirstEnergy initially identified applicable legal obligations as defined under the standard for nuclear power plant decommissioning, reclamation of a sludge disposal pond related to the Bruce Mansfield Plant and closure of two coal ash disposal sites. The ARO liability associated with decommissioning was $1.069 billion as of December 31, 2005 and included $1.054 billion for decommissioning 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 utilized an expected cash flow approach to measure the fair value of the nuclear decommissioning ARO.

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.

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

FirstEnergy maintains nuclear decommissioning trust funds that are legally restricted for purposes of settling the nuclear decommissioning ARO. As of December 31, 2005, the fair value of the decommissioning trust assets was $1.752 billion.

FirstEnergy implemented FIN 47, "Accounting for Conditional Asset Retirement Obligations", an interpretation of SFAS 143, on December 31, 2005. 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 obligation to remediate asbestos, lead paint abatement and other remediation costs at retired generating units was developed based on site specific studies performed by an independent engineer. The cost to remediate asbestos, lead paint and other environmental liabilities at active generating units was calculated utilizing a per-kilowatt removal cost developed from the independent studies completed at the retired generating units, applied to the specific kilowatt capacity of each individual active generating unit. The costs of asbestos, lead paint and other remediation at the Company's substation control rooms, service center buildings, line shops and office buildings were based on costs incurred during recent remediation projects performed at each of these locations. The conditional ARO liability was developed utilizing an expected cash flow approach (as discussed in SFAC No. 7). The Company used a probability weighted analysis to estimate when remediation payments would begin.

The following table describes the changes to the ARO balances during 2005 and 2004.

ARO Reconciliation	2005	2004
	(In millions)	
Balance at beginning of year	$1,078	$1,179
Liabilities incurred	–	–
Liabilities settled	–	–
Accretion	70	75
Revisions in estimated cash flows	(79)	(176)
FIN 47 ARO	57	–
Balance at end of year	$1,126	$1,078

The following table provides the year-end balance of the conditional ARO as if FIN 47 had been adopted on January 1, 2005 and 2004, respectively:

Adjusted ARO Reconciliation	2005	2004
	(In millions)	
Beginning balance as of January 1	$54	$51
Accretion	3	3
Ending balance as of December 31	$57	$54

The following table provides the effect on income as if FIN 47 had been applied during 2004 and 2003.

Effect of the Change in Accounting Principle Applied Retroactively	2004	2003
	(In millions, except per share amounts)	
Net income as reported	$ 878	$ 423
Increase (Decrease):		
Depreciation of asset retirement cost	–	–
Accretion of ARO liability	(3)	(2)
Income tax effect	1	1
Net income adjusted	$ 876	$ 422
Basic earnings per share of common stock:		
As reported	$2.68	$1.39
As adjusted	$2.68	$1.39
Diluted earnings per share of common stock:		
As reported	$2.67	$1.39
As adjusted	$2.66	$1.38

13. SHORT-TERM BORROWINGS AND BANK LINES OF CREDIT

FirstEnergy had approximately $731 million of short-term indebtedness as of December 31, 2005, comprised of $439 million in borrowings from a $2 billion revolving line of credit, $280 million in borrowings through $550 million of available accounts receivables financing and $12 million of other bank borrowings. Total short-term bank lines of committed credit to FirstEnergy and the Companies as of December 31, 2005 were approximately $2.6 billion.

On June 14, 2005, FirstEnergy, OE, Penn, CEI, TE, JCP&L, Met-Ed, Penelec, FES and ATSI, as Borrowers, entered into a syndicated $2 billion five-year revolving credit facility with a syndicate of banks that expires in June 2010. Borrowings under the facility are available to each Borrower separately and mature on the earlier of 364 days from the date of borrowing or the commitment expiration date, as the same may be extended. As of December 31, 2005, FirstEnergy was the only borrower on this revolver with an outstanding balance of $439 million. The annual facility fees are 0.15% to 0.50%.

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 and outstanding balance by company, as of December 31, 2005, appear in the table that follows.

Subsidiary Company	Parent Company	Capacity	Outstanding Balance	Annual Facility Fee
		(In millions)		
OES Capital, Incorporated	OE	$170	$140	0.20%
Centerior Funding Corp.	CEI	200	140	0.25
Penn Power Funding LLC	Penn	25	–	0.15
Met-Ed Funding LLC	Met-Ed	80	–	0.15
Penelec Funding LLC	Penelec	75	–	0.15
		$550	$280	

All of the receivables financing agreements will terminate in 2006 and are expected to be renewed prior to expiration.

The weighted average interest rates on short-term borrowings outstanding as of December 31, 2005 and 2004 were 4.68% and 2.35% respectively. The annual facility fees on all current committed short-term bank lines of credit range from 0.15% to 0.50%.

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 $1.7 billion of insurance coverage for replacement power costs. Under these policies, FirstEnergy can be assessed a maximum of approximately $80 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, 2005, outstanding guarantees and other assurances aggregated approximately $3.4 billion – contract guarantees ($1.7 billion), surety bonds ($0.3 billion) and LOC ($1.4 billion).

FirstEnergy guarantees energy and energy-related payments of its subsidiaries involved in energy commodity activities principally to facilitate normal physical transactions involving electricity, gas, emission allowances and coal. FirstEnergy also provides guarantees to various providers of subsidiary financing principally for the acquisition of property, plant and equipment. These agreements legally obligate FirstEnergy to fulfill the obligations of those subsidiaries directly involved in energy and energy-related transactions or financing where the law might otherwise limit the counterparties' claims. If demands of a counterparty were to exceed the ability of a subsidiary to satisfy existing obligations, FirstEnergy's guarantee enables the counterparty's legal claim to be satisfied by other FirstEnergy assets. The likelihood is remote that such parental guarantees of $0.8 billion (included in the $1.7 billion discussed above) as of December 31, 2005 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. The following table summarizes collateral provisions as of December 31, 2005:

Collateral Provisions	Exposure	Collateral Paid Cash	Collateral Paid LOC	Remaining Exposure
		(In millions)		
Credit rating downgrade	$380	$78	$ –	$302
Adverse Event	74	–	–	74
Total	$454	$78	$ –	$376

Most of FirstEnergy's surety bonds are backed by various indemnities common within the insurance industry. Surety bonds and related FirstEnergy guarantees of $312 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 ($36 million as of December 31, 2005), which is renewable and declines yearly based upon the senior outstanding debt of TEBSA.

(C) ENVIRONMENTAL MATTERS

Various federal, state and local authorities regulate the Companies with regard to air and water quality and other environmental matters. The effects of compliance on the Companies with regard to environmental matters could have a material adverse effect on FirstEnergy's earnings and competitive position 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 2006 through 2010.

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

On December 1, 2005, FirstEnergy issued a comprehensive report to shareholders regarding air emissions regulations and an assessment of its future risks and mitigation efforts.

Clean Air Act Compliance

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

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

National Ambient Air Quality Standards

In July 1997, the EPA promulgated changes in the NAAQS for ozone and proposed a new NAAQS for fine particulate matter. On March 10, 2005, the EPA finalized the "Clean Air Interstate Rule" 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 provides each affected state until 2006 to develop implementing regulations to achieve additional reductions of NOx and SO_2 emissions in two phases (Phase I in 2009 for NOx, 2010 for SO_2 and Phase II in 2015 for both NOx and SO_2). FirstEnergy's Michigan, Ohio and Pennsylvania fossil-fired generation facilities will be subject to caps on SO_2 and NOx emissions, whereas its New Jersey fossil-fired generation facilities will be subject to only a cap on NOx 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. NOx 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 NOx 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. On March 14, 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 NOx 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. We would prefer an output-based generation-neutral methodology in which allowances are allocated based on megawatts of power produced. Since this approach is based on output, new and non-emitting generating facilities, including renewables and nuclear, would be entitled to their proportionate share of the allowances. Consequently, we would be disadvantaged if these model rules were implemented because our substantial reliance on non-emitting (largely nuclear) generation is not recognized under input-based allocation.

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 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 W. H. Sammis Plant New Source Review litigation. This settlement agreement was approved by the Court on July 11, 2005, and requires reductions of NOx and SO_2 emissions at the W. H. Sammis Plant and other 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 settlement agreement. Capital expenditures necessary to meet those requirements are currently estimated to be $1.5 billion (the primary portion of which is expected to be spent in the 2008 to 2011 time period). On August 26, 2005, FGCO entered into an agreement with Bechtel Power Corporation (Bechtel), under which Bechtel will engineer, procure, and construct air quality control systems for the reduction of sulfur dioxide emissions. The settlement agreement also requires OE and Penn to spend up to $25 million toward environmentally beneficial projects, which include wind energy purchased power agreements over a 20-year term. OE and Penn agreed to pay a civil penalty of $8.5 million. Results in 2005 included the penalties payable by OE and Penn of $7.8 million and $0.7 million, respectively. OE and Penn also recognized liabilities 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 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.

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 species are drawn into a facility's cooling water system. FirstEnergy is conducting comprehensive demonstration studies, due in 2008, to determine the operational measures, equipment or restoration activities, if any, necessary for compliance by its facilities with the performance standards. FirstEnergy is unable to predict the outcome of such studies. Depending on the outcome of such studies, the future cost of compliance with these standards may require material capital expenditures.

Regulation of Hazardous Waste

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

The Companies have been named as PRPs at waste disposal sites, which may require cleanup under the Comprehensive Environmental Response, Compensation, and Liability Act of 1980. Allegations of disposal of hazardous substances at historical sites and the liability involved are often unsubstantiated and subject to dispute; however, federal law provides that all PRPs for a particular site are liable on a joint and several basis. Therefore, environmental liabilities that are considered probable have been recognized on the Consolidated Balance Sheet as of December 31, 2005, 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 $64 million have been accrued through December 31, 2005.

(D) OTHER LEGAL PROCEEDINGS

Power Outages and Related Litigation

In July 1999, the Mid-Atlantic States experienced a severe heat wave, which resulted in power outages throughout the service territories of many electric utilities, including JCP&L's territory. In an investigation into the causes of the outages and the reliability of the transmission and distribution systems of all four 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. On September 8, 2004, the New Jersey Supreme Court denied the motions filed by plaintiffs and JCP&L for leave to appeal the decision of the Appellate Division. JCP&L has filed a motion for summary judgment. FirstEnergy is unable to predict the outcome of these matters and no liability has been accrued as of December 31, 2005.

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 website (www.doe.gov). FirstEnergy believes that the final report does not provide a complete and comprehensive picture of the conditions that contributed to the August 14, 2003 power outages and that it does not adequately address the underlying causes of the outages. FirstEnergy remains convinced that the outages cannot be explained by events on any one utility's system. The final report 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 also is proceeding with the implementation of the recommendations regarding enhancements to regional reliability 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, and therefore FirstEnergy has not accrued a liability as of December 31, 2005 for any expenditures in excess of those actually incurred through that date. 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. Finally, the PUCO is continuing to review FirstEnergy's filing that addressed upgrades to control room computer hardware and software and enhancements to the training of control room operators before determining the next steps, if any, in the proceeding.

FirstEnergy companies also are defending six separate complaint cases before the PUCO relating to the August 14, 2003 power outage. 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. Of the four other pending PUCO complaint cases, three were filed by various insurance carriers either in their own name as subrogees or in the name of their insured. In each of the four 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 claims 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. The fourth case involves the claim of a non-customer seeking reimbursement for losses incurred when its store was burglarized on August 14, 2003. In addition to these six cases, the Ohio Companies were named as respondents in a regulatory proceeding that was initiated at the PUCO in response to complaints alleging failure to provide reasonable and adequate service stemming primarily from the August 14, 2003 power outages. No estimate of potential liability is available for any of these cases.

In addition to the above proceedings, FirstEnergy was named in a complaint filed in Michigan State Court by an individual who is not a customer of any FirstEnergy company. A responsive pleading to this matter has been filed. FirstEnergy was also named, along with several other entities, in a complaint in New Jersey State Court. The allegations against FirstEnergy are based, in part, on an alleged failure to protect the citizens of Jersey City from an electrical power outage. No FirstEnergy entity serves any customers in Jersey City. A responsive pleading has been filed. No estimate of potential liability has been undertaken in either of these matters.

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 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 May 11, 2005, FENOC received a subpoena for documents related to outside meetings attended by Davis-Besse personnel on corrosion and cracking of control rod drive mechanisms and additional root cause evaluations. On January 20, 2006, FENOC announced that it has 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, which expires on December 31, 2006, 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 will 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 remains in compliance with the agreement, which FENOC fully intends to do. FENOC has agreed to pay a penalty of $28 million (which is not deductible for income tax purposes) which reduced FirstEnergy's earnings by $0.09 per common share in the fourth quarter of 2005. As part of the deferred prosecution agreement entered into with the DOJ, $4.35 million of that amount will be directed to community service projects.

On April 21, 2005, the NRC issued a NOV and proposed a $5 million civil penalty related to the degradation of the Davis-Besse reactor vessel head issue described 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.

Effective July 1, 2005, the NRC oversight panel for Davis-Besse was terminated and Davis-Besse returned to the standard NRC reactor oversight process. At that time, NRC inspections were augmented to include inspections to support the NRC's Confirmatory Order dated March 8, 2004 that was issued at the time of startup and to address an NRC White Finding related to the performance of the emergency sirens. By letter dated December 8, 2005, the NRC advised FENOC that the White Finding had been closed.

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. FENOC operates the Perry Nuclear Power Plant.

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 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. By an inspection report dated January 18, 2006, the NRC closed one of the White Findings (related to emergency preparedness) which led to the multiple degraded cornerstones.

On May 26, 2005, the NRC held a public meeting to discuss its oversight of the Perry Plant. While the NRC stated that the plant continued to operate safely, the NRC also stated that the overall performance had not substantially improved since the heightened inspection was initiated. The NRC reiterated this conclusion in its mid-year assessment letter dated August 30, 2005. On September 28, 2005, the NRC sent a CAL to FENOC describing commitments that FENOC had made to improve the performance of Perry 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. 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 unable to predict a potential impact, its ultimate disposition could have a material adverse effect on FirstEnergy's or its subsidiaries' financial condition, results of operations and cash flows.

As of December 16, 2005 NGC acquired ownership of the nuclear generation assets transferred from OE, CEI, TE and Penn with the exception of leasehold interests of OE and TE in certain of the nuclear plants that are subject to sale and leaseback arrangements with non-affiliates.

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 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. 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.

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 Arbitrator decided not to hear testimony on damages and closed the proceedings. On September 9, 2005, the Arbitrator issued an opinion to award approximately $16 million to the bargaining unit employees. On February 6, 2006, the federal court granted a Union motion to dismiss JCP&L's appeal of the award as premature. JCP&L will file its 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.

The City of Huron filed a complaint against OE with the PUCO challenging the ability of electric distribution utilities to collect transition charges from a customer of a newly-formed municipal electric utility. The complaint was filed on May 28, 2003, and OE timely filed its response on June 30, 2003. In a related filing, the Ohio Companies filed for approval with the PUCO of a tariff that would specifically allow the collection of transition charges from customers of municipal electric utilities formed after 1998. An adverse ruling could negatively affect full recovery of transition charges by the utility. Hearings on the matter were held in August 2005. Initial briefs from all parties were filed on September 22, 2005 and reply briefs were filed on October 14, 2005. It is unknown when the PUCO will decide this case.

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

On May 13, 2005, Penn, and on May 18, 2005, the Ohio Companies 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 by way of dividend and, in the case of CEI and TE, a sale at net book value. FENOC continues to operate and maintain the nuclear generation assets.

These transactions were 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 to a separate corporate entity. The transactions essentially completed the divestitures contemplated by the restructuring plans by transferring the ownership interests to NGC and FGCO without impacting the operation of the plants.

16. SEGMENT INFORMATION

FirstEnergy has two reportable segments: regulated services and power supply management services. The aggregate "Other" segments do not individually meet the criteria to be considered a reportable segment. FirstEnergy's primary segment is its regulated services segment, whose operations include the regulated sale of electricity and distribution and transmission services by its eight 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 now own the generation facilities of OE, CEI, TE and Penn resulting from the deregulation of the Companies' electric generation business. "Other" consists of MYR (a construction service company), retail natural gas operations (recer ly sold – see Note 8) and telecommunications services. T assets and revenues for the other business operations are below the quantifiable threshold for operating segments for separate disclosure as "reportable segments."

The regulated services segment designs, constructs, operates and maintains FirstEnergy's regulated transmission and distribution systems. Its revenues are primarily derived from electricity delivery and transition 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 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 all of the electric power needs of FirstEnergy's end-use customers through retail and wholesale arrangements, including regulated retail sales to meet the PLR requirements of our Ohio and Pennsylvania companies and competitive retail sales to commercial and industrial businesses primarily in Ohio, Pennsylvania and Michigan. This business segment owns and operates our generating facilities and purchases electricity from the wholesale market to meet our 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 for interim periods in 2004 and 2003 have been reclassified to conform to the current year business segment organization and operations and the reclassification of discontinued operations (see Note 2(J)). FSG is being disclosed as a reporting segment due to its subsidiaries qualifying as held for sale (see Note 2(J) for discussion of the divestiture of three of those subsidiaries in 2005). 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	Facilities Services	Other	Reconciling Adjustments	Consolidated
	(In millions)					
2005						
External revenues	$5,483	$5,739	$212	$533	$22	$11,989
Internal revenues	270	–	–	–	(270)	–
Total revenues	5,753	5,739	212	533	(248)	11,989
Depreciation and amortization	1,392	45	–	2	26	1,465
Investment income	218	–	–	–	–	218
Net interest charges	390	54	1	6	206	657
Income taxes	763	36	3	13	(61)	754
Income before discontinued operations and cumulative effect of accounting change	1,067	23	(8)	17	(226)	873
Discontinued operations	–	–	13	5	–	18
Cumulative effect of accounting change	(21)	(9)	–	–	–	(30)
Net income	1,046	14	5	22	(226)	861
Total assets	23,975	6,556	69	536	705	31,841
Total goodwill	5,932	24	–	54	–	6,010
Property additions	788	375	2	6	36	1,207
2004						
External revenues	$5,191	$6,204	$217	$444	$ 4	$12,060
Internal revenues	318	–	–	–	(318)	–
Total revenues	5,509	6,204	217	444	(314)	12,060
Depreciation and amortization	1,422	35	2	3	34	1,496
Investment income	205	–	–	–	–	205
Net interest charges	363	37	1	14	252	667
Income taxes	740	72	(8)	(24)	(107)	673
Income before discontinued operations	1,015	104	(13)	40	(250)	896
Discontinued operations	–	–	(23)	5	–	(18)
Net income	1,015	104	(36)	45	(250)	878
Total assets	28,308	1,488	135	625	479	31,035
Total goodwill	5,951	24	–	75	–	6,050
Property additions	572	246	3	4	21	846
2003						
External revenues	$5,068	$5,487	$179	$547	$44	$11,325
Internal revenues	319	–	–	–	(319)	–
Total revenues	5,387	5,487	179	547	(275)	11,325
Depreciation and amortization	1,423	29	–	2	35	1,489
Investment income	185	–	–	–	–	185
Net interest charges	493	44	1	107	164	809
Income taxes	779	(222)	(34)	(19)	(96)	408
Income before discontinued operations and cumulative effect of accounting change	1,063	(320)	(55)	(64)	(180)	444
Discontinued operations	–	–	(26)	(97)	–	(123)
Cumulative effect of accounting change	101	–	–	1	–	102
Net income	1,164	(320)	(81)	(160)	(180)	423
Total assets	29,789	1,423	166	912	620	32,910
Total goodwill	5,993	24	36	75	–	6,128
Property additions	434	335	4	9	74	856

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
2005	$10,546	$708
2004	10,831	551
2003	10,205	601

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

Geographic Information

Following the sales of international operations in 2002 through January of 2004, less than 1% of FirstEnergy's revenues and assets were in foreign countries in 2003 and 2004. See Note 8 for a discussion of the divestitures.

17. NEW ACCOUNTING STANDARDS AND INTERPRETATIONS

FSP FAS 115-1 and FAS 124-1, "The Meaning of Other-Than-Temporary Impairment and its Application to Certain Investments"

Issued in November 2005, FSP 115-1 and FAS 124-1 addresses the determination as to when an investment is considered impaired, whether that impairment is other than temporary, and the measurement of an impairment loss. The FSP finalized and renamed EITF 03-1 and 03-1-a to FSP FAS 115-1. This FSP will (1) nullify certain requirements of Issue 03-1 and supersedes EITF topic No. D-44, "Recognition of Other Than Temporary Impairment upon the Planned Sale of a Security Whose Cost Exceeds Fair Value," (2) clarify that an investor should recognize an impairment loss no later than when the impairment is deemed other than temporary, even if a decision to sell has not been made, and (3) be effective for other-than-temporary impairment and analyses conducted in periods beginning after September 15, 2005. The FSP requires prospective application with an effective date for reporting periods beginning after December 15, 2005. FirstEnergy is currently evaluating this FSP and any impact on its investments.

FSP No. FAS 13-1, "Accounting for Rental Costs Incurred during the Construction Period"

Issued in October 2005, FSP No. FAS 13-1 requires rental costs associated with ground or building operating leases that are incurred during a construction period to be recognized as rental expense. The effective date of the FSP guidance is the first reporting period beginning after December 15, 2005. FirstEnergy will apply this FSP to all construction projects, beginning January 1, 2006.

EITF Issue 04-13, "Accounting for Purchases and Sales of Inventory with the Same Counterparty"

In September 2005, the EITF reached a final consensus on Issue 04-13 concluding that two or more legally separate exchange transactions with the same counterparty should be combined and considered as a single arrangement for purposes of applying APB 29, when the transactions were entered into "in contemplation" of one another. If two transactions are combined and considered a single arrangement, the EITF reached a consensus that an exchange of inventory should be accounted for at fair value. Although electric power is not capable of being held in inventory, there is no substantive conceptual distinction between exchanges involving power and other storable inventory. Therefore, FirstEnergy will adopt this EITF effective for new arrangements entered into, or modifications or renewals of existing arrangements, in interim or annual periods beginning after March 15, 2006.

SFAS 154 – "Accounting Changes and Error Corrections – a replacement of APB Opinion No. 20 and FASB Statement No. 3"

In May 2005, the FASB issued SFAS 154 to change the requirements for accounting and reporting a change in accounting principle. It applies to all voluntary changes in accounting principle and to changes required by an accounting pronouncement when that pronouncement does not include specific transition provisions. This Statement requires retrospective application to prior periods' financial statements of changes in accounting principle, unless it is impracticable to determine either the period-specific effects or the cumulative effect of the change. In those instances, this Statement requires that the new accounting principle be applied to the balances of assets and liabilities as of the beginning of the earliest period for which retrospective application is practicable and that a corresponding adjustment be made to the opening balance of retained earnings (or other appropriate components of equity or net assets in the statement of financial position) for that period rather than being reported in the Consolidated Statements of Income. This Statement also requires that a change in depreciation, amortization, or depletion method for long-lived, nonfinancial assets be accounted for as a change in accounting estimate affected by a change in accounting principle. The provisions of this Statement are effective for accounting changes and corrections of errors made in fiscal years beginning after December 15, 2005. FirstEnergy and the Companies adopted this Statement effective January 1, 2006.

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

In December 2004, the FASB issued SFAS 153 amending APB 29, which was based on the principle that nonmonetary assets should be measured based on the fair value of the assets exchanged. The guidance in APB 29 included certain exceptions to that principle. SFAS 153 eliminates the exception from fair value measurement for nonmonetary exchanges of similar productive assets and replaces it with an exception for exchanges that do not have commercial substance. This Statement specifies that a nonmonetary exchange has commercial substance if the future cash flows of the entity are expected to change significantly as a result of the exchange. The provisions of this Statement are effective January 1, 2006 for FirstEnergy. This FSP is not expected to have a material impact on FirstEnergy's financial statements.

SFAS 123(R), "Share-Based Payment"

In December 2004, the FASB issued SFAS 123(R), a revision to SFAS 123, which requires expensing stock options in the financial statements. Important to applying the new standard is understanding how to (1) measure the fair value of stock-based compensation awards and (2) recognize the related compensation cost for those awards. For an award to qualify for equity classification, it must meet certain criteria in SFAS 123(R). An award that does not meet those criteria will be classified as a liability and remeasured each period. SFAS 123(R) retains SFAS 123's requirements on accounting for income tax effects of stock-based compensation. In April 2005, the SEC delayed the effective date of SFAS 123(R) to annual, rather than interim, periods that begin after June 15, 2005. FirstEnergy adopted this Statement effective January 1, 2006 with modified prospective application. The Company uses the Black-Scholes option-pricing model to value options for disclosure purposes only and continued to apply this pricing model with the adoption of SFAS 123(R). As discussed in Note 4, the Company reduced its use of stock options beginning in 2005, with no stock options being awarded subsequent to 2004. As a result, all currently unvested stock options will vest by 2008. We expect the adoption of SFAS 123(R) will increase annual compensation expense (after-tax) by approximately $7 million, $2 million and $0.5 million in 2006, 2007 and 2008, respectively or $0.02 per share in 2006 and less than $0.01 per share in 2007 and 2008.

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

In November 2004, the FASB issued SFAS 151 to clarify the accounting for abnormal amounts of idle facility expense, freight, handling costs and wasted material (spoilage). Previous guidance stated that in some circumstances these costs may be "so abnormal" that they would require treatment as current period costs. SFAS 151 requires abnormal amounts for these items to always be recorded as current period costs. In addition, this Statement requires that allocation of fixed production overheads to the cost of conversion be based on the normal capacity of the production facilities. The provisions of this statement are effective for inventory costs incurred by FirstEnergy beginning January 1, 2006. FirstEnergy 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 2005 and 2004. Certain financial results have been reclassified to discontinued operations from amounts previously reported due to the divestiture of certain non-core businesses in 2005 as discussed in Note 2(J).

Three Months Ended	March 31, 2005	June 30, 2005	Sept. 30, 2005	Dec. 31, 2005
	(In millions, except per share amounts)			
Revenues	$2,750	$2,843	$3,504	$2,892
Expenses	2,358	2,309	2,861	2,395
Other Expense, net	130	114	74	122
Income Taxes	121	241	237	155
Income Before Discontinued Operations and Cumulative Effect of Accounting Change	141	179	332	220
Discontinued Operations (Net of Income Taxes)	19	(1)	–	–
Cumulative Effect of Accounting Change (Net of Income Taxes)	–	–	–	(30)
Net Income	$ 160	$ 178	$ 332	$ 190
Basic Earnings Per Share of Common Stock:				
Before Discontinued Operations and Cumulative Effect of Accounting Change	$ 0.43	$ 0.54	$ 1.01	$ 0.67
Discontinued Operations	0.06	–	–	–
Cumulative Effect of Accounting Change	–	–	–	(0.09)
Basic Earnings Per Share of Common Stock	$ 0.49	$ 0.54	$ 1.01	$ 0.58
Diluted Earnings Per Share of Common Stock:				
Before Discontinued Operations and Cumulative Effect of Accounting Change	$ 0.42	$ 0.54	$ 1.01	$ 0.67
Discontinued Operations	0.06	–	–	–
Cumulative Effect of Accounting Change	–	–	–	(0.09)
Diluted Earnings Per Share of Common Stock	$ 0.48	$ 0.54	$ 1.01	$ 0.58

Three Months Ended	March 31, 2004	June 30, 2004	Sept. 30, 2004	Dec. 31, 2004
	(In millions, except per share amounts)			
Revenues	$2,934	$2,929	$3,365	$2,832
Expenses	2,524	2,418	2,752	2,335
Other Expense, net	123	133	102	104
Income Taxes	115	176	215	167
Income Before Discontinued Operations	172	202	296	226
Discontinued Operations (Net of Income Taxes)	2	2	2	(24)
Net Income	$174	$204	$298	$202
Basic Earnings Per Share of Common Stock:				
Before Discontinued Operations	0.53	0.61	0.90	0.69
Discontinued Operations	–	0.01	0.01	(0.08)
Basic Earnings Per Share of Common Stock	$ 0.53	$ 0.62	$ 0.91	$ 0.61
Diluted Earnings Per Share of Common Stock:				
Before Discontinued Operations	0.53	0.61	0.90	0.69
Discontinued Operations	–	0.01	0.01	(0.08)
Diluted Earnings Per Share of Common Stock	$ 0.53	$ 0.62	$ 0.91	$ 0.61

Results for the fourth quarter of 2005 included a $30 million, net of tax, or $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) or $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), or $0.09 per share, charge related to the Davis-Besse DOJ and NRC fines (see Note 14). Net income for the fourth quarter also included a $15 million, net of tax, or $0.05 per share, charge relating to prior periods as a result of a JCP&L tax audit adjustment which was 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 2004 or 2005, nor was it material to the consolidated balance sheets and consolidated cash flows for any of these quarters.

Results for the fourth quarter of 2004 included a $37 million net-of-tax, or $0.11 per share, non-cash charge for impairment of goodwill and other assets of FSG as required by SFAS 142 and SFAS 144 (see Note 2 (H)).

Consolidated Financial and Pro Forma Combined Operating Statistics (Unaudited)

	2005	2004	2003	2002	2001	2000	1995
GENERAL FINANCIAL INFORMATION (Dollars in millions)							
Revenues	$11,989	$12,060	$11,325	$11,169	$ 6,924	$ 6,308	$2,501
Net Income	$861	$878	$423	$553	$646	$599	$295
SEC Ratio of Earnings to Fixed Charges	2.73	2.62	1.75	1.88	2.22	2.10	2.32
Capital Expenditures	$1,144	$731	$792	$904	$888	$569	$196
Total Capitalization[a]	$17,527	$18,938	$18,414	$18,686	$21,339	$11,205	$5,566
Capitalization Ratios[a]:							
Common Stockholders' Equity	52.4%	45.3%	45.0%	37.7%	34.7%	41.5%	43.3%
Preferred and Preference Stock:							
Not Subject to Mandatory Redemption	1.1	1.8	1.8	1.8	2.2	5.8	3.8
Subject to Mandatory Redemption	–	–	–	2.3	2.8	1.4	2.9
Long-Term Debt	46.5	52.9	53.2	58.2	60.3	51.3	50.0
Total Capitalization	100.0%	100.0%	100.00%	100.00%	100.00%	100.00%	100.00%
Average Capital Costs:							
Preferred and Preference Stock	5.67%	6.51%	6.47%	7.50%	7.90%	7.92%	7.59%
Long-Term Debt	6.05%	5.93%	6.08%	6.56%	6.98%	7.84%	8.00%
COMMON STOCK DATA							
Earnings per Share[b]:							
Basic	$ 2.66	$ 2.74	$ 1.46	$ 2.09	$ 2.82	$ 2.69	$ 2.05
Diluted	$ 2.65	$ 2.73	$ 1.46	$ 2.08	$ 2.81	$ 2.69	$ 2.05
Return on Average Common Equity[b]	10.0%	10.6%	5.9%	8.2%	12.9%	13.0%	12.5%
Dividends Paid per Share	$ 1.67	$ 1.50	$ 1.50	$ 1.50	$ 1.50	$ 1.50	$ 1.50
Dividend Payout Ratio[b]	63%	55%	103%	72%	53%	56%	73%
Dividend Yield	3.4%	3.8%	4.3%	4.5%	4.3%	4.8%	6.4%
Price/Earnings Ratio[b]	18.4	14.4	24.1	15.8	12.4	11.7	11.5
Book Value per Share	$ 27.98	$ 26.20	$ 25.35	$ 24.01	$ 25.29	$ 21.29	$16.73
Market Price per Share	$ 48.99	$ 39.51	$ 35.20	$ 32.97	$ 34.98	$ 31.56	$23.50
Ratio of Market Price to Book Value	175%	151%	139%	137%	138%	148%	140%
OPERATING STATISTICS[c]							
Generation Kilowatt-Hour Sales (Millions):							
Residential	34,716	31,781	31,322	31,937	32,708	32,519	30,575
Commercial	32,878	32,114	32,311	32,892	32,170	33,139	28,389
Industrial	32,907	31,675	32,451	32,726	33,024	31,140	34,663
Other	547	504	554	531	536	522	1,432
Total Retail	101,048	96,074	96,638	98,086	98,438	97,320	95,059
Total Wholesale	28,521	53,268	42,059	30,007	20,240	13,761	14,484
Total Sales	129,569	149,342	138,697	128,093	118,678	111,081	109,543
Customers Served:							
Residential	3,941,030	3,916,855	3,874,052	3,868,499	3,833,013	3,798,716	3,651,383
Commercial	509,933	500,695	496,253	471,440	464,053	472,410	431,206
Industrial	10,637	10,597	10,871	18,416	18,652	18,996	21,130
Other	6,124	5,654	5,635	5,716	5,762	6,001	7,608
Total	4,467,724	4,433,801	4,386,811	4,364,071	4,321,480	4,296,123	4,111,327
Number of Employees	14,586	15,245	15,905	17,560	18,700	18,912	21,919

[a] 2001 capitalization includes approximately $1.4 billion of long-term debt (excluding long-term debt due to be repaid within one year) included in "Liabilities Related to Assets Pending Sale" on the Consolidated Balance Sheet as of December 31, 2001.
[b] Before discontinued operations in 2005, 2004, 2003 and 2002, and accounting changes in 2005, 2003 and 2001.
[c] Reflects pro forma combined FirstEnergy and GPU statistics in 2000 and 2001 and pro forma combined Ohio Edison, Centerior and GPU statistics in 1995.

SHAREHOLDER INFORMATION

Shareholder Services, Transfer Agent and Registrar

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

Stock Listings and Trading

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

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

Dividends

Proposed dates for the payment of FirstEnergy common stock dividends in 2006 are:

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

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

Direct Dividend Deposit

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

Combining Stock Accounts

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

Stock Investment Plan

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

Safekeeping of Shares

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

Form 10-K Annual Report

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

Institutional Investor and Security Analyst Inquiries

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

Annual Meeting of Shareholders

Shareholders are invited to attend the 2006 Annual Meeting of Shareholders on Tuesday, May 16, at 10:30 a.m. Eastern time, at the John S. Knight Center, 77 East Mill Street, in Akron, Ohio. Registered shareholders not attending the meeting can appoint a proxy and vote on the items of business by telephone, Internet or by completing and returning the proxy card that is sent to them. Shareholders whose shares are held in the name of a broker can attend the meeting if they present a letter from their broker indicating ownership of FirstEnergy common stock on the record date of March 21, 2006.

FirstEnergy has included as Exhibit 31 to its Annual Report on Form 10-K for fiscal year 2005 filed with the Securities and Exchange Commission certificates of FirstEnergy's Chief Executive Officer and Chief Financial Officer certifying the quality of the Company's public disclosure. FirstEnergy's Chief Executive Officer has also submitted to the New York Stock Exchange (NYSE) a certificate certifying that he was not aware of any violation by FirstEnergy of the NYSE corporate governance listing standards as of the date of the certification.

Printed on recycled paper

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

2005 Annual Report