FirstEnergy

76 South Main Street
Akron, Ohio 44308

Richard H. Marsh, CFA
Senior Vice President and
Chief Financial Officer

330-384-5318
Fax: 384-5669

March 24, 2005

U.S. Nuclear Regulatory Commission
Attn: Document Control Desk
Washington, D.C. 20555

Re: Saxton Nuclear Experimental Corporation
Operating License No. DPR-4, Docket No. 50-146
Parent Guarantee for Decommissioning Funding

Dear Sir:

I am the Senior Vice President and Chief Financial Officer of Jersey Central Power & Light Company, Metropolitan Edison Company and Pennsylvania Electric Company (collectively, hereinafter referred to as the "the Companies"), which are wholly owned electric utility operating subsidiaries of FirstEnergy Corp., a registered public utility holding company. The Companies are the sole shareholders of Saxton Nuclear Experimental Corporation ("SNEC"). Jersey Central Power & Light Company owns 44%, Metropolitan Edison Company owns 32%, and Pennsylvania Electric Company owns 24% of the shares of SNEC, respectively. This letter is in support of the Companies' use of the financial test and parent guarantee originally dated February 19, 2001 in the amount of $20 million and to demonstrate continued financial assurance for the decommissioning of the Saxton facility, in accordance with 10 C.F.R. § 50.75(e)(1)(iii)(B).

The Saxton facility is a shutdown pressurized water reactor owned by the Saxton Nuclear Experimental Corporation and located north of the Borough of Saxton in Liberty Township, Bedford County, Pennsylvania. GPU Nuclear, Inc. is authorized by NRC License No. DPR-4 to possess, manage, use and maintain, but not operate, the facility. GPU Nuclear is also a wholly owned subsidiary of FirstEnergy Corp. Saxton is in the final stages of decommissioning, with license termination and final site restoration scheduled for the third quarter of 2005. GPU Nuclear has estimated that it will cost approximately $1.919 million to complete decommissioning. The respective share of the estimated decommissioning costs for each of the Companies based on ownership would therefore be approximately $845,000 for the Jersey Central Power & Light Company, approximately $590,000 for the Metropolitan Edison Company, and approximately $485,000 for the Pennsylvania Electric Company.

Each of the Companies, severally and not jointly, guarantees, through parent company guarantees submitted February 19, 2001, to demonstrate compliance under 10 CFR Part 50, its respective share (in respect to its ownership interest) of the remaining cost of decommissioning of the Saxton facility. Each of the Companies is required to file a Form 10-K with the U.S. Securities and Exchange Commission for the latest fiscal year.

A001

The fiscal year of the Companies ends on December 31. Worksheets demonstrating that each of the Companies meets the financial test in 10 C.F.R. Part 30, Appendix A, Section II.A.2, for its respective share of the remaining Saxton decommissioning costs are attached hereto and incorporated herein by reference. The figures for the items marked with an asterisk on the worksheets are derived from the Companies' independently audited financial statements and notes to the financial statements for the year ended December 31, 2004. The Companies' Form 10-K for the year ended December 31, 2004 is attached.

I hereby certify that the content of this letter is true and correct to the best of my knowledge.

Very truly yours,

Richard H. Marsh

Richard H. Marsh
Senior Vice President
and Chief Financial Officer

March 24, 2005

Attachments

cc: Hubert J. Miller, NRC
Laurie A. Peluso, NRC
William C. Huffman, NRC
David Kern, NRC
Gary R. Leidich
James J. Byrne, Three Mile Island
George A. Kuehn, Jr., Saxton
G. Benz
E. J. Sitarz (w/o attachs.)
D. C. Perrine (w/o attachs.)
R. T. Conlin

Jersey Central Power & Light Company
Financial Test: Alternative II
($ - in thousands)

1	Decommissioning cost estimates for facility NRC License No. DPR-4 (total of all cost estimates shown in paragraph above)	$ 845 A
2	Current bond rating of most recent issuance of this firm and name of rating service Standard & Poor's	BBB+
3	Date of issuance of bond	04/20/04
4	Date of maturity of bond	05/01/16
*5.	Tangible net worth** (if any portion of estimates for decommissioning is included in total liabilities on your firm's financial statement, add the amount of that portion to this line).	$ 1,171,171
*6.	Total assets in United States (required only if less than 90 percent of firm's assets are located in the United States)	n/a

		Yes	No
7	Is line 5 at least $10 million?	X	
8	Is line 5 at least 6 times line 1?	X	
*9.	Are at least 90 percent of firm's assets located in the United States? If not, complete line 10.	X	
10	Is line 6 at least 6 times line 1?		

* Denotes figures derived from financial statements.

** Tangible Net Worth is defined as net worth minus goodwill, patents, trademarks and copyrights.

A Represents Jersey Central Power & Light Company's proportionate share of the total estimated remaining decommissioning liability of $1.9 million as of December 31, 2004.

PRICEWATERHOUSECOOPERS

PricewaterhouseCoopers LLP
BP Tower, 27th Floor
200 Public Square
Cleveland OH 44114-2301
Telephone (216) 875 3000
Facsimile (216) 566 7846

Report of Independent Accountants

To Jersey Central Power & Light Company:

We have performed the procedures enumerated below, which were agreed to by management of Jersey Central Power & Light Company (the "Company"), solely to you in evaluating the Company's compliance with the financial test as of December 31, 2004 performed in accordance with the U.S. Nuclear Regulatory Commission (the "NRC") Regulation 10 CFR, Section 50.75(e)(1)(iii)(B) as mandated by the Parent Company Guaranty dated February 19, 2001. Management is responsible for the Company's compliance with those requirements. This agreed-upon procedures engagement was conducted in accordance with attestation standards established by the American Institute of Certified Public Accountants. The sufficiency of these procedures is solely the responsibility of management of the Company. Consequently, we make no representation regarding the sufficiency of the procedures described below either for the purpose for which this report has been requested or for any other purpose.

We have read the letter, dated March 24, 2005, from your Senior Vice President and Chief Financial Officer to the NRC and compared the amount in item 1 of the Company's Financial Test: Alternative II with the corresponding amount in the Company's accounting records and found it to be in agreement.

We compared the amount in item 5 of the Company's Financial Test: Alternative II to a schedule prepared by the Company from its accounting records and found it to be in agreement. We (a) compared the amounts on the schedule to corresponding amounts appearing in the accounting records and found such amounts to be in agreement and (b) determined that the schedule was mathematically accurate.

We were not engaged to and did not conduct an examination, the objective of which would be the expression of an opinion on compliance. Accordingly, we do not express such an opinion. Had we performed additional procedures, other matters might have come to our attention that would have been reported to you.

This report is intended solely for the information and use of the Company and is not intended to be and should not be used by anyone other than these specified parties.

PricewaterhouseCoopers LLP

March 29, 2005

Metropolitan Edison Company
Financial Test: Alternative II
($ - in thousands)

1	Decommissioning cost estimates for facility NRC License No. DPR-4 (total of all cost estimates shown in paragraph above)	$ 590 A
2	Current bond rating of most recent issuance of this firm and name of rating service Standard & Poor's	BBB-
3	Date of issuance of bond	03/25/04
4	Date of maturity of bond	04/01/14
*5.	Tangible net worth** (if any portion of estimates for decommissioning is included in total liabilities on your firm's financial statement, add the amount of that portion to this line).	$ 416,424
*6.	Total assets in United States (required only if less than 90 percent of firm's assets are located in the United States)	n/a

		Yes	No
7	Is line 5 at least $10 million?	X	
8	Is line 5 at least 6 times line 1?	X	
*9.	Are at least 90 percent of firm's assets located in the United States? If not, complete line 10.	X	
10	Is line 6 at least 6 times line 1?		

* Denotes figures derived from financial statements.

** Tangible Net Worth is defined as net worth minus goodwill, patents, trademarks and copyrights

A Represents Metropolitan Edison Company's proportionate share of the total estimated remaining decommissioning liability of $1.9 million as of December 31, 2004.

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Report of Independent Accountants

To Metropolitan Edison Company:

We have performed the procedures enumerated below, which were agreed to by management of Metropolitan Edison Company (the "Company"), solely to assist you in evaluating the Company's compliance with the financial test as of December 31, 2004 performed in accordance with the U.S. Nuclear Regulatory Commission (the "NRC") Regulation 10 CFR, Section 50.75(e)(1)(iii)(B) as mandated by the Parent Company Guaranty dated February 19, 2001. Management is responsible for the Company's compliance with those requirements. This agreed-upon procedures engagement was conducted in accordance with attestation standards established by the American Institute of Certified Public Accountants. The sufficiency of these procedures is solely the responsibility of management of the Company. Consequently, we make no representation regarding the sufficiency of the procedures described below either for the purpose for which this report has been requested or for any other purpose.

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PricewaterhouseCoopers LLP

March 29, 2005

Pennsylvania Electric Company
Financial Test: Alternative II
($ - in thousands)

1	Decommissioning cost estimates for facility NRC License No. DPR-4 (total of all cost estimates shown in paragraph above)	$ 485 A
2	Current bond rating of most recent issuance of this firm and name of rating service Standard & Poor's	BBB-
3	Date of issuance of bond	03/31/04
4	Date of maturity of bond	04/01/14
*5.	Tangible net worth** (if any portion of estimates for decommissioning is included in total liabilities on your firm's financial statement, add the amount of that portion to this line).	$ 417,489
*6.	Total assets in United States (required only if less than 90 percent of firm's assets are located in the United States)	n/a

		Yes	No
7	Is line 5 at least $10 million?	X	
8	Is line 5 at least 6 times line 1?	X	
*9.	Are at least 90 percent of firm's assets located in the United States? If not, complete line 10.	X	
10	Is line 6 at least 6 times line 1?		

* Denotes figures derived from financial statements.
** Tangible Net Worth is defined as net worth minus goodwill, patents, trademarks and copyrights.
A Represents Pennsylvania Electric Company's proportionate share of the total estimated remaining decommissioning liability of $1.9 million as of December 31, 2004.

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Report of Independent Accountants

To Pennsylvania Electric Company:

We have performed the procedures enumerated below, which were agreed to by management of Pennsylvania Electric Company (the "Company"), solely to assist you in evaluating the Company's compliance with the financial test as of December 31, 2004 performed in accordance with the U.S. Nuclear Regulatory Commission (the "NRC") Regulation 10 CFR, Section 50.75(e)(1)(iii)(B) as mandated by the Parent Company Guaranty dated February 19, 2001. Management is responsible for the Company's compliance with those requirements. This agreed-upon procedures engagement was conducted in accordance with attestation standards established by the American Institute of Certified Public Accountants. The sufficiency of these procedures is solely the responsibility of management of the Company. Consequently, we make no representation regarding the sufficiency of the procedures described below either for the purpose for which this report has been requested or for any other purpose.

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PricewaterhouseCoopers LLP

March 29, 2005

ANNUAL REPORT 2004

Jersey Central Power & Light
A FirstEnergy Company

JERSEY CENTRAL POWER & LIGHT COMPANY

2004 ANNUAL REPORT TO STOCKHOLDERS

Jersey Central Power & Light Company is a wholly owned electric utility operating subsidiary of FirstEnergy Corp. It engages in the distribution and sale of electric energy in an area of approximately 3,300 square miles in New Jersey. It also engages in the sale, purchase and interchange of electric energy with other electric companies. The area it serves has a population of approximately 2.5 million.

Contents	Page

GLOSSARY OF TERMS

The following abbreviations and acronyms are used in this report to identify Jersey Central Power & Light Company and its affiliates:

ATSI	American Transmission Systems, Inc., owns and operates transmission facilities
CEI	The Cleveland Electric Illuminating Company, an affiliated Ohio electric utility
Companies	OE, CEI, TE, Penn, JCP&L, Met-Ed and Penelec
FES	FirstEnergy Solutions Corp., provides energy-related products and services
FESC	FirstEnergy Service Company, provides legal, financial, and other corporate support services
FirstEnergy	FirstEnergy Corp., a registered public utility holding company
GPU	GPU, Inc., former parent of JCP&L, Met-Ed and Penelec, which merged with FirstEnergy on November 7, 2001
GPUS	GPU Service Company, previously provided corporate support services
JCP&L	Jersey Central Power & Light Company
JCP&L Transition	JCP&L Transition Funding LLC, a Delaware limited liability company and issuer of transition Bonds
Met-Ed	Metropolitan Edison Company, an affiliated Pennsylvania electric utility
OE	Ohio Edison Company, an affiliated Ohio electric utility
Penelec	Pennsylvania Electric Company, an affiliated Pennsylvania electric utility
Penn	Pennsylvania Power Company, an affiliated Pennsylvania electric utility
TE	The Toledo Edison Company, an affiliated Ohio electric utility

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

AOCL	Accumulated Other Comprehensive Loss
APB 29	APB Opinion No. 29, "Accounting for Stock Issued to Employees"
ARO	Asset Retirement Obligation
BGS	Basic Generation Service
CTC	Competitive Transition Charge
ECAR	East Central Area Reliability Coordination Agreement
EITF	Emerging Issues Task Force
EITF 03-1	EITF Issue No. 03-1, "The Meaning of Other-Than-Temporary and Its Application to Certain Investments"
EITF 03-16	EITF Issue No. 03-16, "Accounting for Investments in Limited Liability Companies"
EITF97-4	EITF Issue No. 97-4 "Deregulation of the Pricing of Electricity – Issues Related to the Application of FASB Statements No. 71 and 101"
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FIN 46R	FASB Interpretation (revised December 2003), "Consolidation of Variable Interest Entities"
FMB	First Mortgage Bonds
FSP	FASB Staff Position
FSP EITF 03-1-1	FASB Staff Position No. EITF Issue 03-1-1, "Effective Date of Paragraphs 10-20 of EITF Issue No. 03-1, *The Meaning of Other-Than-Temporary Impairment and Its Application to Certain Investments*"
FSP 106-1	FASB Staff Position No.106-1, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003"
FSP 109-1	FASB Staff Position No. 109-1, "Application of FASB Statement No. 109, Accounting for Income Taxes, to the Tax Deduction and Qualified Production Activities provided by the American Jobs Creation Act of 2004"
GAAP	Accounting Principles Generally Accepted in the United States
IRS	Internal Revenue Service
Medicare Act	Medicare Prescription Drug, Improvement and Modernization Act of 2003
MISO	Midwest Independent Transmission System Operator, Inc.
Moody's	Moody's Investors Service
MTC	Market Transition Charge
MW	Megawatts
NERC	North American Electric Reliability Council
NJBPU	New Jersey Board of Public Utilities
NUG	Non-Utility Generation
OCI	Other Comprehensive Income
OPEB	Other Post-Employment Benefits
PJM	PJM Interconnection L.L.C.

GLOSSARY OF TERMS, Cont'd

PRP	Potentially Responsible Party
PUCO	Public Utilities Commission of Ohio
PUHCA	Public Utility Holding Company Act
S&P	Standard & Poor's Ratings Service
SBC	Societal Benefits Charge
SEC	United States Securities and Exchange Commission
SFAS	Statement of Financial Accounting Standards
SFAS 71	SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation"
SFAS 87	SFAS No. 87, "Employers' Accounting for Pensions"
SFAS 101	SFAS No. 101, "Accounting for Discontinuation of Application of SFAS 71"
SFAS 106	SFAS No. 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions"
SFAS 115	SFAS No. 115, "Accounting for Certain Investments in Debt and Equity Securities"
SFAS 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"
SPE	Special Purpose Entity
TBC	Transition Bond Charge
TMI-1	Three Mile Island Unit 1
TMI-2	Three Mile Island Unit 2
VIE	Variable Interest Entity

MANAGEMENT REPORTS

Responsibility for Financial Statements

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

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

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

Internal Control Over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rule 13a-15(f) of the Securities Exchange Act of 1934. Using the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in *Internal Control – Integrated Framework*, management conducted an evaluation of the effectiveness of the Company's internal control over financial reporting under the supervision of the chief executive officer and the chief financial officer. Based on that evaluation, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2004. Management's assessment of the effectiveness of the Company's internal control over financial reporting, as of December 31, 2004, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears on page 2.

Report of Independent Registered Public Accounting Firm

To the Stockholders and Board of
Directors of Jersey Central
Power & Light Company:

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

Consolidated financial statements

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

As discussed in Note 9 to the consolidated financial statements, the Company changed its method of accounting for asset retirement obligations as of January 1, 2003. As discussed in Note 6 to the consolidated financial statements, the Company changed its method of accounting for the consolidation of variable interest entities as of December 31, 2003.

Internal control over financial reporting

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

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

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

PricewaterhouseCoopers LLP
Cleveland, Ohio
March 7, 2005

JERSEY CENTRAL POWER & LIGHT COMPANY

SELECTED FINANCIAL DATA

	2004	2003	2002	Nov. 7 - Dec. 31, 2001	Jan. 1 - Nov. 6, 2001	2000
			(Dollars in thousands)			
Operating Revenues	$ 2,206,987	$ 2,359,646	$ 2,328,415	$ 282,902	$ 1,838,638	$ 1,979,297
Operating Income	$ 183,909	$ 146,775	$ 335,209	$ 43,666	$ 292,847	$ 283,227
Net Income	$ 111,639	$ 68,017	$ 251,895	$ 30,041	$ 34,467	$ 210,812
Earnings on Common Stock	$ 111,139	$ 68,129	$ 253,359	$ 29,343	$ 29,920	$ 203,908
Total Assets	$ 7,291,184	$ 7,579,044	$ 8,052,755	$ 8,039,998		$ 6,009,054
Capitalization as of December 31:						
Common Stockholder's Equity	$ 3,155,362	$ 3,153,974	$ 3,274,069	$ 3,163,701		$ 1,459,260
Preferred Stock-						
Not Subject to Mandatory Redemption	12,649	12,649	12,649	12,649		12,649
Subject to Mandatory Redemption	–	–	–	44,868		51,500
Company-Obligated Mandatorily Redeemable Preferred Securities	–	–	125,244	125,250		125,000
Long-Term Debt	1,238,984	1,095,991	1,210,446	1,224,001		1,093,987
Total Capitalization	$ 4,406,995	$ 4,262,614	$ 4,622,408	$ 4,570,469		$ 2,742,396
Capitalization Ratios:						
Common Stockholder's Equity	71.6%	74.0%	70.8%	69.2%		53.2%
Preferred Stock-						
Not Subject to Mandatory Redemption	0.3	0.3	0.3	0.3		0.5
Subject to Mandatory Redemption	–	–	–	1.0		1.9
Company-Obligated Mandatorily Redeemable Preferred Securities	–	–	2.7	2.7		4.5
Long-Term Debt	28.1	25.7	26.2	26.8		39.9
Total Capitalization	100.0%	100.0%	100.0%	100.0%		100.0%
Distribution Kilowatt-Hour Deliveries (Millions):						
Residential	9,355	9,104	8,976	1,428	7,042	8,087
Commercial	8,877	8,620	8,509	1,330	6,787	7,706
Industrial	3,070	3,046	3,171	474	2,670	3,307
Other	73	89	81	17	66	82
Total	21,375	20,859	20,737	3,249	16,565	19,182
Customers Served:						
Residential	941,917	931,227	921,716	909,494		896,629
Commercial	115,861	114,270	112,385	109,985		107,479
Industrial	2,666	2,705	2,759	2,785		2,835
Other	1,320	1,345	1,393	1,484		1,551
Total	1,061,764	1,049,547	1,038,253	1,023,748		1,008,494

JERSEY CENTRAL POWER & LIGHT COMPANY

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

This discussion includes forward-looking statements based on information currently available to management. Such statements are subject to certain risks and uncertainties. These statements typically contain, but are not limited to, the terms "anticipate," "potential," "expect," "believe," "estimate" and similar words. Actual results may differ materially due to the speed and nature of increased competition and deregulation in the electric utility industry, economic or weather conditions affecting future sales and margins, changes in markets for energy services, changing energy and commodity market prices, replacement power costs being higher than anticipated or inadequately hedged, maintenance costs being higher than anticipated, legislative and regulatory changes (including revised environmental requirements), adverse regulatory or legal decisions and outcomes (including revocation of necessary licenses or operating permits, fines or other enforcement actions and remedies) of governmental investigations, including by the Securities and Exchange Commission as disclosed in our Securities and Exchange Commission filings, the availability and cost of capital, our ability to experience growth in the distribution business, our ability to access the public securities and other capital markets, further investigation into the causes of the August 14, 2003, regional power outage and the outcome, cost and other effects of present and potential legal and administrative proceedings and claims related to the outage, the risks and other factors discussed from time to time in our Securities and Exchange Commission filings, and other similar factors. We expressly disclaim any current intention to update any forward-looking statements contained herein as a result of new information, future events, or otherwise.

Reclassifications

As discussed in Note 1 to the consolidated financial statements, certain prior year amounts have been reclassified to conform to the current year presentation. Revenue amounts related to transmission activities previously recorded as wholesale electric sales revenues were reclassified as transmission revenues. Expenses (including transmission and congestion charges) were reclassified among purchased power, other operating costs and amortization of regulatory assets to conform to the current year presentation. These reclassifications did not change previously reported results in 2003 and 2002.

Results of Operations

Earnings on common stock increased to $111 million from $68 million in 2003 principally due to the absence of non-cash charges aggregating $185 million ($109 million after tax) from a 2003 rate case decision disallowing recovery of certain regulatory assets (see Regulatory Matters) and reduced purchased power costs in 2004 which were partially offset by a decline in operating revenues. In 2003, earnings on common stock decreased to $68 million, from $253 million in 2002, as a result of the disallowed costs from the 2003 rate case decision. In addition, higher operating revenues were more than offset by increases in purchased power and other operating costs causing a decline in earnings.

Operating revenues decreased $153 million or 6.5% in 2004 compared with 2003. The decrease in revenues was due to a $107 million decline in distribution throughput revenues and a $49 million decline in wholesale revenues partially offset by a $11 million increase in retail generation revenues. Our BGS obligation has been transferred to external parties as a result of an NJBPU auction process that extended the termination of our BGS obligation through July 2005 (see Note 7 - Regulatory Matters). We had entered into long-term power purchase agreements in connection with the divestiture of our generation facilities and had sold any power in excess of our retail customer needs to the wholesale market. The long-term purchase agreements ended after the first quarter of 2003 and as a result, sales to the wholesale market subsequently decreased. Retail generation sales revenues increased by $11 million in 2004 compared to 2003 due to higher unit prices resulting from the BGS auction. This increase more than offset a composite 13.2% decrease in kilowatt-hour sales (commercial – 16.0% and industrial - 63.4%), which reflected increases in electric generation services to commercial and industrial customers provided by alternative suppliers. The shopping percentage in our franchise area increased 16.7 percentage points and 46.0 percentage points, for the commercial and industrial sectors respectively, while the percentage of shopping by residential customers was relatively unchanged.

The $107 million decrease in distribution deliveries was due to lower unit prices that more than offset the impact of the 2.5% volume increase in 2004 from the previous year. The lower prices reflected the impact of the distribution rate decrease effective August 1, 2003. Warmer temperatures in the summer and improving economic conditions resulted, in large part, in higher residential, commercial and industrial demand.

Operating revenues increased $31 million in 2003 compared with 2002 due to an $87 million increase in wholesale revenues offset by lower revenues from our distribution deliveries. The wholesale revenues increase in 2003 reflected the impact of the BGS auction discussed above.

Distribution deliveries increased slightly in 2003 from the previous year. Lower unit prices in 2003 more than offset the impact of the increased volume and reduced revenues by $64 million. In addition, lower 2003 revenues reflected the impact of the distribution rate decrease effective August 1, 2003. Colder temperatures early in the year resulted in higher residential and commercial demand, which was partially offset by a decrease in industrial demand.

Generation sales revenues in 2003 compared to 2002 were lower by $24 million due to an 8.7% decrease in kilowatt-hour sales. The decrease reflected a 9.1 percentage point increase in customers choosing an alternate supplier in 2003 compared to 2002. The reverse was true in 2002 where some customers who were receiving their power from alternate suppliers returned to us as full service customers.

Changes in kilowatt-hour sales by customer class in 2004 and 2003 are summarized in the following table:

Changes in Kilowatt-hour Sales	**2004**	**2003**
Increase (Decrease)		
Electric Generation:		
Retail	(13.2)%	(8.7)%
Wholesale	(19.1)%	23.1 %
Total Electric Generation Sales	(14.7)%	(2.4)%
Distribution Deliveries:		
Residential	2.8 %	1.4 %
Commercial	3.0 %	1.3 %
Industrial	0.8 %	(3.9)%
Total Distribution Deliveries	2.5 %	0.6 %

Operating Expenses and Taxes

Total operating expenses and taxes decreased $190 million in 2004, after increasing $220 million in 2003, compared to the prior year. These increases include the non-cash charges in 2003 for amounts disallowed by the NJBPU in its rate case decision (see Regulatory Matters), of which $153 million was charged to purchased power and $33 million was charged to amortization of regulatory assets. The following table presents changes in 2004 and 2003 from the prior year by expense category.

Operating Expenses and Taxes - Changes *Increase (Decrease)*	**2004**	**2003**
	(In millions)	
Fuel and purchased power costs	$ (220)	$ 234
Other operating costs	(18)	68
Provision for depreciation	(24)	(23)
Amortization of regulatory assets	15	73
General taxes	9	(2)
Income taxes	48	(130)
Total operating expenses and taxes	$ (190)	$ 220

Excluding the disallowed deferred energy costs of $153 million in 2003, fuel and purchased power decreased $67 million in 2004 compared to 2003. The lower purchased power costs reflected lower kilowatt-hour purchases due to reduced generation sales requirements as discussed above. Other operating expenses decreased $18 million in 2004 compared to 2003, due to cost containment efforts as demonstrated by the 7% decline in the number of employees and the absence in 2004 of storm restoration costs incurred in the third quarter of 2003.

Depreciation expense declined $24 million in 2004 and $23 million in 2003 compared to the preceding year due to reduced depreciation rates effective August 1, 2003 in connection with the NJBPU rate case decision (see Regulatory Matters). Amortization of regulatory assets, excluding $33 million of disallowed costs in 2003 from the rate decision discussed above, increased $48 million in 2004 and $40 in 2003 due to increased regulatory asset recovery in connection with the NJBPU rate case decision.

In 2003, excluding the disallowed deferred energy costs of $153 million, fuel and purchased power costs increased $81 million, compared to 2002. The increase was due primarily to more power being purchased through two-party agreements and changes to the deferred energy and capacity costs. Other operating expenses increased $68 million in 2003 compared to 2002, due to higher employee benefit costs, storm restoration expenses and costs associated with an accelerated reliability plan within our service territory.

Net Interest Charges

Net interest charges decreased $6 million in 2004 and $5 million in 2003, compared to the previous year, reflecting debt redemptions of $290 million and $252 million, respectively. Those decreases were partially offset by interest on $300 million of senior notes issued in April 2004 and $150 million of senior notes issued in May 2003 which were used to redeem outstanding securities in the second and third quarters of 2003.

Preferred Stock Dividend Requirements

Preferred stock dividend requirements were unchanged in 2004 and decreased $1.4 million in 2003, compared to the prior year, due to the redemptions of cumulative preferred stock pursuant to mandatory and optional sinking fund provisions. We realized non-cash gains of $0.6 million in 2003 on the reacquisition of preferred stock.

Capital Resources and Liquidity

Our cash requirements in 2004 for operating expenses, construction expenditures and scheduled debt maturities were met with a combination of cash from operations and funds from the capital markets. During 2005 and thereafter, we expect to meet our contractual obligations with cash from operations.

Changes in Cash Position

As of December 31, 2004, we had $0.2 million of cash and cash equivalents compared with $0.3 million as of December 31, 2003. The major sources for changes in these balances are summarized below.

Cash Flows From Operating Activities

Our net cash provided from operating activities was $263 million in 2004, $180 million in 2003 and $302 million in 2002, summarized as follows:

Operating Cash Flows	2004	2003	2002
		(In millions)	
Cash earnings[1]	$ 230	$ 325	$ 281
Pension trust contribution	(37)	–	–
Working capital and other	70	(145)	21
Total	$ 263	$ 180	$ 302

[1] Cash earnings is a non-GAAP measure (see reconciliation below).
[2] Pension trust contribution net of $25 million of income tax benefits.

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	2004	2003	2002
		(In millions)	
Net Income (GAAP)	$ 112	$ 68	$ 252
Non-Cash Charges (Credits):			
Provision for depreciation	75	99	121
Amortization of regulatory assets	279	263	190
Revenue credits to customers	–	(72)	(43)
Disallowed regulatory assets	–	153	–
Deferred costs recoverable as regulatory assets	(263)	(276)	(352)
Deferred income taxes	30	62	112
Other non-cash expenses	(3)	28	1
Cash earnings (Non-GAAP)	$ 230	$ 325	$ 281

Net cash provided from operating activities increased by $83 million in 2004 and decreased by $121 million in 2003, as compared to the previous year. The increase in 2004 was due to a $215 million increase in working capital which was partially offset by a $95 million decrease in cash earnings as described under "Results of Operations" and a $37 million after-tax voluntary pension trust contribution. The increase in working capital and other was attributable to a $151 million increase in payables and a $53 million increase associated with a NUG power contract restructuring. The decrease in 2003 was due to a $166 million increase in working capital and other requirements (primarily from a $170 million reduction in payables) which was partially offset by a $44 million increase in cash earnings.

Cash Flows From Financing Activities

Net cash used for financing activities was $82 million, $139 million and $140 million in 2004, 2003 and 2002, respectively. These amounts reflect redemptions of debt and preferred stock, in addition to payments of $90 million in 2004, $138 million in 2003 and $191 million in 2002 for common stock dividends to FirstEnergy. The following table provides details regarding new issues and redemptions during each year:

Securities Issued or Redeemed In	2004	2003	2002
		(In millions)	
New Issues			
Secured Notes	$ 300	$ 150	$ –
Transition Bonds (See Note 8(C))	–	–	320
Redemptions			
First Mortgage Bonds	$ 290	$ 150	$ 192
Medium Term Notes	–	102	–
Preferred Stock	–	125	52
Transition Bonds	16	–	–
Other	3	–	4
Total Redemptions	$ 309	$ 377	$ 248
Short-term Borrowings, net	$ 18	$ 231	$ (18)

We had $249 million of short-term indebtedness at the end of 2004, compared to $231 million of short-term debt at the end of 2003. The Company has obtained authorization from the SEC to incur short-term debt up to its charter limit of $415 million (including the utility money pool). We will not issue FMB other than as collateral for senior notes, since our senior note indentures prohibit (subject to certain exceptions) us from issuing any debt which is senior to the senior notes. As of December 31, 2004, we had the capability to issue $644 million of additional senior notes based upon FMB collateral. At year-end 2004, based upon applicable earnings coverage tests and our charter, we could issue $583 million of preferred stock (assuming no additional debt was issued).

We have the ability to borrow from our regulated affiliates and FirstEnergy to meet our short-term working capital requirements. FESC administers this money pool and tracks surplus funds of FirstEnergy and its regulated subsidiaries. Companies receiving a loan under the money pool agreements must repay the principal, 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 the pool and is based on the average cost of funds available through the pool. The average interest rate for borrowings under these arrangements in 2004 was 1.43%.

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

Ratings of Securities

	Securities	S&P	Moody's	Fitch
FirstEnergy	Senior unsecured	BB+	Baa3	BBB-
JCP&L	Senior secured	BBB+	Baa1	BBB+
	Preferred stock	BB	Ba1	BBB

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

Cash Flows From Investing Activities

Cash used in investing activities increased $136 million in 2004 and decreased $143 million in 2003. The increase in 2004 resulted primarily from a $56 million increase in property additions and a $79 million decrease in loan repayments from associated companies. The 2003 change was principally due to a $155 million increase in loan repayments from associated companies.

Our capital spending for the period 2005-2007 is expected to be approximately $511 million for property additions and improvements, of which approximately $178 million applies to 2005.

Contractual Obligations

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

Contractual Obligations	Total	2005	2006-2007	2008-2009	Thereafter
			(In millions)		
Long-term debt [2]	$ 1,264	$ 17	$ 226	$ 44	$ 977
Short-term borrowings	249	249	-	-	-
Operating leases	62	2	3	4	53
Purchases [1]	3,374	568	1,068	837	901
Total	$ 4,949	$ 836	$ 1,297	$ 885	$ 1,931

[1] Power purchases under contracts with fixed or minimum quantities and approximate timing.
[2] Amounts reflected do not include interest on long-term debt.

Market Risk Information

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

Commodity Price Risk

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

Increase (Decrease) in the Fair Value of Commodity Derivative Contracts

	Non-Hedge	Hedge (In millions)	Total
Change in the Fair Value of Commodity Derivative Contracts			
Outstanding net asset as of January 1, 2004	$ 16	$ –	$ 16
New contract value when entered	–	–	–
Additions/Change in value of existing contracts	(1)	–	(1)
Change in techniques/assumptions	–	–	–
Settled contracts	–	–	–
Net Assets - Derivatives Contracts as of December 31, 2004[1]	**$ 15**	**$ –**	**$ 15**
Income Statement Impact of Changes in Commodity Derivative Contracts(2)	$ (1)	$ –	$ (1)

(1) Includes $15 million in non-hedge commodity derivative contracts which are offset by a regulatory liability.
(2) Represents the increase in value of existing contracts, settled contracts and changes in techniques/assumptions.

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

	Non-Hedge	Hedge (In millions)	Total
Non-Current–			
Other Deferred Charges	$ 15	$ –	$ 15
Net assets	**$ 15**	**$ –**	**$ 15**

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 derivative contracts by year are summarized in the following table:

Source of Information – Fair Value by Contract Year

	2005	2006	2007	2008	Thereafter	Total
				(In millions)		
Other external sources[1]	$ 4	$ 3	$ –	$ –	$ –	$ 7
Prices based on models	–	–	2	2	4	8
Total[2]	**$ 4**	**$ 3**	**$ 2**	**$ 2**	**$ 4**	**$ 15**

(1) Broker quote sheets.
(2) Includes $15 million from an embedded option that is offset by a regulatory liability and does not affect earnings.

We perform sensitivity analyses to estimate our exposure to the market risk of our commodity position. A hypothetical 10% adverse shift in quoted market prices in the near term on derivative instruments would not have had a material effect on our consolidated financial position or cash flows as of December 31, 2004.

Interest Rate Risk

Our exposure to fluctuations in market interest rates is reduced since our debt has fixed interest rates, as noted in the following table.

Comparison of Carrying Value to Fair Value

Year of Maturity	2005	2006	2007	2008	2009	There-after	Total	Fair Value
				(Dollars in millions)				
Assets								
Investments Other Than Cash and Cash Equivalents-								
Fixed Income						$ 218	$ 218	$ 218
Average interest rate						4.6%	4.6%	
Liabilities								
Long-term Debt and Other Long-Term Obligations:								
Fixed rate	$ 17	$ 208	$ 18	$ 19	$ 25	$ 977	$ 1,264	$ 1,252
Average interest rate	4.2%	6.3%	4.2%	5.4%	5.7%	6.1%	6.1%	
Short-term Borrowings	249						$ 249	$ 249
Average interest rate	2.0%						2.0%	

Equity Price Risk

Included in nuclear decommissioning trusts are marketable equity securities carried at their current fair value of approximately $80 million and $69 million at December 31, 2004 and 2003, respectively. A hypothetical 10% decrease in prices quoted by stock exchanges would result in a $8 million reduction in fair value as of December 31, 2004. (See Note 4 Fair Value of Financial Instruments)

Outlook

Beginning in 1999, all of our customers were able to select alternative energy suppliers. We continue to deliver power to homes and businesses through our existing distribution system, which remains regulated. To support customer choice, rates were restructured into unbundled service charges and additional non-bypassable charges to recover stranded costs.

Regulatory assets are costs which have been authorized by the NJBPU and the FERC 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 when incurred. All of our regulatory assets are expected to continue to be recovered under the provisions of the regulatory proceedings discussed below. Our regulatory assets totaled $2.2 billion and $2.6 billion as of December 31, 2004 and December 31, 2003, respectively.

Regulatory Matters

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

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

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

Employee Matters

On December 8, 2004, employees represented by IBEW System Council U-3 began a strike against the Company. The Company continues to utilize management, other non-union personnel from around FirstEnergy's system and contractors to perform service reliability and priority maintenance work while the union members are on strike. The labor agreement between the Company and System Council U-3 originally expired on October 31, 2003 but was extended several times and ultimately expired on December 7, 2004. The Company and the leadership of System Council U-3 continue to negotiate in an attempt to reach a new agreement and end the work stoppage. It is unknown when such an agreement will be reached or when the work stoppage will end.

Environmental Matters

We have been named as a PRP 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 be held liable on a joint and several basis. Therefore, environmental liabilities that are considered probable have been recognized on the Consolidated Balance Sheet as of December 31, 2004, based on estimates of the total costs of cleanup, our proportionate responsibility for such costs and the financial ability of other nonaffiliated entities to pay. We have accrued liabilities aggregating approximately $47 million as of December 31, 2004, which are being recovered through a non-bypassable SBC. We do not believe environmental remediation costs will have a material adverse effect on our financial condition, cash flows or results of operations.

Power Outages and Related Litigation

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

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

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

Legal Matters

Various lawsuits, claims (including claims for asbestos exposure) and proceedings related to our normal business operations are pending against us, the most significant of which are described above.

Critical Accounting Policies

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

Regulatory Accounting

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

Revenue Recognition

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

Pension and Other Postretirement Benefits Accounting

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

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

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

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

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

In the third quarter of 2004, FirstEnergy made a $500 million voluntary contribution to its pension plan (our share was $62 million). Prior to this contribution, projections indicated that cash contributions of approximately $600 million would have been required during the 2006 to 2007 time period under minimum funding requirements established by the IRS. FirstEnergy's election to pre-fund the plan is expected to eliminate that funding requirement.

As a result of our voluntary contribution and the increased market value of pension plan assets, we reduced our accrued benefit cost as of December 31, 2004 by $46 million. As prescribed by SFAS 87, we increased our additional minimum liability by $9 million, offset by a charge to OCI. The balance in AOCL of $53 million (net of $37 million in deferred taxes) will reverse in future periods to the extent the fair value of trust assets exceeds the accumulated benefit obligation.

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

Long-Lived Assets

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

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

Nuclear Decommissioning

In accordance with SFAS 143, we recognize an ARO for the future decommissioning of TMI-2. The ARO liability represents an estimate of the fair value of our current obligation related to nuclear decommissioning and the retirement of other assets. A fair value measurement inherently involves uncertainty in the amount and timing of settlement of the liability. We used an expected cash flow approach to measure the fair value of the nuclear decommissioning ARO. This approach applies probability weighting to discounted future cash flow scenarios that reflect a range of possible outcomes. The scenarios consider settlement of the ARO at the expiration of the nuclear power plant's current license and settlement based on an extended license term.

Goodwill

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

JERSEY CENTRAL POWER & LIGHT COMPANY

CONSOLIDATED STATEMENTS OF INCOME

	2004	2003	2002
		(In thousands)	
OPERATING REVENUES (Note 2(H))	$ 2,206,987	$ 2,359,646	$ 2,328,415
OPERATING EXPENSES AND TAXES:			
Fuel and purchased power (Note 2(H))	1,166,430	1,386,899	1,153,415
Other operating costs (Note 2(H))	350,709	368,714	300,602
Provision for depreciation	75,163	98,711	121,444
Amortization of regulatory assets	278,559	263,227	190,200
General taxes	62,792	53,481	56,049
Income taxes	89,425	41,839	171,496
Total operating expenses and taxes	2,023,078	2,212,871	1,993,206
OPERATING INCOME	183,909	146,775	335,209
OTHER INCOME	7,761	7,026	7,653
NET INTEREST CHARGES:			
Interest on long-term debt	80,840	87,681	92,314
Allowance for borrowed funds used during construction	(615)	(296)	(583)
Deferred interest	(3,545)	(8,639)	(8,815)
Other interest expense	3,351	1,691	(2,643)
Subsidiary's preferred stock dividend requirements	–	5,347	10,694
Net interest charges	80,031	85,784	90,967
NET INCOME	111,639	68,017	251,895
PREFERRED STOCK DIVIDEND REQUIREMENTS	500	500	2,125
GAIN ON PREFERRED STOCK REACQUISITION	–	(612)	(3,589)
EARNINGS ON COMMON STOCK	$ 111,139	$ 68,129	$ 253,359

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

JERSEY CENTRAL POWER & LIGHT COMPANY

CONSOLIDATED BALANCE SHEETS

As of December 31,	2004	2003
	(In thousands)	
ASSETS		
UTILITY PLANT:		
In service	$ 3,730,767	$ 3,642,467
Less-Accumulated provision for depreciation	1,380,775	1,367,042
	2,349,992	2,275,425
Construction work in progress	75,012	48,985
	2,425,004	2,324,410
OTHER PROPERTY AND INVESTMENTS:		
Nuclear plant decommissioning trusts	138,205	125,945
Nuclear fuel disposal trust	159,696	155,774
Long-term notes receivable from associated companies	20,436	19,579
Other	19,379	18,744
	337,716	320,042
CURRENT ASSETS:		
Cash and cash equivalents	162	271
Receivables-		
Customers (less accumulated provisions of $3,881,000 and $4,296,000 respectively, for uncollectible accounts)	201,415	198,061
Associated companies	86,531	70,012
Other (less accumulated provisions of $162,000 and $1,183,000 respectively)	39,898	46,411
Materials and supplies, at average cost	2,435	2,480
Prepayments and other	31,489	49,360
	361,930	366,595
DEFERRED CHARGES:		
Regulatory assets	2,176,520	2,558,214
Goodwill	1,985,036	2,001,302
Other	4,978	8,481
	4,166,534	4,567,997
	$ 7,291,184	$ 7,579,044
CAPITALIZATION AND LIABILITIES		
CAPITALIZATION(See Consolidated Statements of Capitalization):		
Common stockholder's equity	$ 3,155,362	$ 3,153,974
Preferred stock not subject to mandatory redemption	12,649	12,649
Long-term debt	1,238,984	1,095,991
	4,406,995	4,262,614
CURRENT LIABILITIES:		
Currently payable long-term debt	16,866	175,921
Notes payable (Note 10)-		
Associated companies	248,532	230,985
Accounts payable-		
Associated companies	20,605	42,410
Other	124,733	105,815
Accrued taxes	2,626	919
Accrued interest	10,359	14,843
Other	65,130	58,094
	488,851	628,987
NONCURRENT LIABILITIES:		
Power purchase contract loss liability	1,268,478	1,473,070
Accumulated deferred income taxes	645,741	640,208
Nuclear fuel disposal costs	169,884	167,936
Asset retirement obligation	72,655	109,851
Retirement benefits	103,036	159,219
Other	135,544	137,159
	2,395,338	2,687,443
COMMITMENTS AND CONTINGENCIES (Notes 5 and 11).		
	$ 7,291,184	$ 7,579,044

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

JERSEY CENTRAL POWER & LIGHT COMPANY

CONSOLIDATED STATEMENTS OF CAPITALIZATION

As of December 31,	2004	2003
(Dollars in thousands, except per share amounts)		
COMMON STOCKHOLDER'S EQUITY:		
Common stock, par value $10 per share, authorized 16,000,000 shares 15,371,270 shares outstanding	$ 153,713	$ 153,713
Other paid-in capital	3,013,912	3,029,894
Accumulated other comprehensive loss (Note 2(F))	(55,534)	(51,765)
Retained earnings (Note 8(A))	43,271	22,132
Total common stockholder's equity	3,155,362	3,153,974

	Number of Shares Outstanding		Optional Redemption Price			
	2004	2003	Per Share	Aggregate		
PREFERRED STOCK NOT SUBJECT TO MANDATORY REDEMPTION (Note 8(B)):						
Cumulative, without par value-Authorized 125,000 shares						
4.00% Series	125,000	125,000	$ 106.50	$ 13,313	12,649	12,649

	2004	2003
LONG-TERM DEBT (Note 8(C)):		
First mortgage bonds:		
7.125% due 2004	–	160,000
6.780% due 2005	–	50,000
6.850% due 2006	40,000	40,000
7.125% due 2009	5,985	6,300
7.100% due 2015	12,200	12,200
8.320% due 2022	–	40,000
7.980% due 2023	–	40,000
7.500% due 2023	125,000	125,000
8.450% due 2025	50,000	50,000
6.750% due 2025	150,000	150,000
Total first mortgage bonds	383,185	673,500
Secured notes:		
6.450% due 2006	150,000	150,000
4.190% due 2007	51,723	67,312
5.390% due 2010	52,297	52,297
5.810% due 2013	77,075	77,075
5.625% due 2016	300,000	–
6.160% due 2017	99,517	99,517
4.800% due 2018	150,000	150,000
Total secured notes	880,612	596,201
Unsecured notes:		
7.69% due 2039	–	2,968
Net unamortized discount on debt	(7,947)	(757)
Long-term debt due within one year	(16,866)	(175,921)
Total long-term debt	1,238,984	1,095,991
TOTAL CAPITALIZATION	$ 4,406,995	4,262,614

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

JERSEY CENTRAL POWER & LIGHT COMPANY

CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDER'S EQUITY

	Comprehensive Income	Common Stock Number of Shares	Common Stock Par Value	Other Paid-In Capital	Accumulated Other Comprehensive Income (Loss)	Retained Earnings
		(Dollars in thousands)				
Balance, January 1, 2002		15,371,270	$ 153,713	$ 2,981,117	$ (472)	$ 29,343
Net income	$ 251,895					251,895
Net unrealized loss on derivative instruments	(393)				(393)	
Comprehensive income	$ 251,502					
Cash dividends on preferred stock						1,465
Cash dividends on common stock						(190,700)
Purchase accounting fair value adjustment				48,101		
Balance, December 31, 2002		15,371,270	153,713	3,029,218	(865)	92,003
Net income	$ 68,017					68,017
Net unrealized loss on derivative instruments	(3,020)				(3,020)	
Minimum liability for unfunded retirement benefits, net of $(32,998,000) of income taxes	(47,880)				(47,880)	
Comprehensive income	$ 17,117					
Cash dividends on preferred stock						(500)
Cash dividends on common stock						(138,000)
Gain on preferred stock reacquisition						612
Purchase accounting fair value adjustment				676		
Balance, December 31, 2003		15,371,270	153,713	3,029,894	(51,765)	22,132
Net income	$ 111,639					111,639
Net unrealized loss on investments	(5)				(5)	
Net unrealized gain on derivative instruments, net of $1,583,000 of income taxes	1,697				1,697	
Minimum liability for unfunded retirement benefits, net of $(3,772,000) of income taxes	(5,461)				(5,461)	
Comprehensive income	$ 107,870					
Cash dividends on preferred stock						(500)
Cash dividends on common stock						(90,000)
Purchase accounting fair value adjustment				(15,982)		
Balance, December 31, 2004		15,371,270	$ 153,713	$ 3,013,912	$ (55,534)	$ 43,271

CONSOLIDATED STATEMENTS OF PREFERRED STOCK

	Not Subject to Mandatory Redemption Number of Shares	Not Subject to Mandatory Redemption Carrying Value	Subject to Mandatory Redemption Number of Shares	Subject to Mandatory Redemption Carrying Value
	(Dollars in thousands)			
Balance, January 1, 2002	125,000	$ 12,649	5,515,001	$ 180,951
Redemptions-				
7.52% Series			(265,000)	(28,951)
8.65% Series			(250,001)	(26,750)
Amortization of fair market Value adjustment				(6)
Balance, December 31, 2002	125,000	12,649	5,000,000	$ 125,244
Redemptions-				
8.56% Series			(5,000,000)	(125,242)
Amortization of fair market value adjustment				(2)
Balance, December 31, 2003	125,000	12,649	–	–
Balance, December 31, 2004	125,000	$ 12,649	–	$ –

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

JERSEY CENTRAL POWER & LIGHT COMPANY

CONSOLIDATED STATEMENTS OF CASH FLOWS

	2004	2003	2002
		(In thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net Income	$ 111,639	$ 68,017	$ 251,895
Adjustments to reconcile net income to net cash from operating activities:			
Provision for depreciation	75,163	98,711	121,444
Amortization of regulatory assets	278,559	263,227	190,200
Deferred costs, net	(263,257)	(276,214)	(351,950)
Deferred income taxes and investment tax credits, net	54,887	62,372	112,315
NUG power contract restructuring	52,800	–	–
Pension trust contribution	(62,499)	–	–
Revenue credits to customers	–	(71,984)	(43,016)
Disallowed regulatory assets	–	152,500	–
Accrued retirement benefit obligation	(2,986)	8,381	–
Accrued compensation, net	1,014	19,864	(59)
Receivables	(13,360)	4,528	(14,542)
Materials and supplies	45	(1,139)	7
Accounts payable	(2,887)	(153,953)	16,399
Other	33,535	5,642	19,597
Net cash provided from operating activities	262,653	179,952	302,290
CASH FLOWS FROM FINANCING ACTIVITIES:			
New Financing-			
Long-term debt	300,000	150,000	318,106
Short-term borrowings, net	17,547	230,985	–
Redemptions and Repayments-			
Preferred stock	–	(125,244)	(51,500)
Long-term debt	(308,872)	(251,815)	(196,033)
Short-term borrowings, net	–	–	(18,149)
Dividend Payments-			
Common stock	(90,000)	(138,000)	(190,700)
Preferred stock	(500)	(5,235)	(2,125)
Net cash used for financing activities	(81,825)	(139,309)	(140,401)
CASH FLOWS FROM INVESTING ACTIVITIES:			
Property additions	(178,877)	(122,930)	(97,346)
Contributions to decommissioning trusts	(2,895)	(2,630)	–
Loan repayments from (payments to) associated companies, net	(857)	78,112	(77,358)
Other	1,692	2,253	(13,786)
Net cash used for investing activities	(180,937)	(45,195)	(188,490)
Net increase (decrease) in cash and cash equivalents	(109)	(4,552)	(26,601)
Cash and cash equivalents at beginning of period	271	4,823	31,424
Cash and cash equivalents at end of period	$ 162	$ 271	$ 4,823
SUPPLEMENTAL CASH FLOWS INFORMATION:			
Cash Paid During the Year-			
Interest (net of amounts capitalized)	$ 83,341	$ 101,432	$ 92,152
Income taxes	$ 58,549	$ 16,883	$ 83,776

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

JERSEY CENTRAL POWER & LIGHT COMPANY

CONSOLIDATED STATEMENTS OF TAXES

	2004	2003	2002
		(In thousands)	
GENERAL TAXES:			
New Jersey Transitional Energy Facilities Assessment*	$ 49,455	$ 38,668	$ 39,387
Real and personal property	4,894	3,889	4,362
Social security and unemployment	8,287	4,826	-
Other	156	6,098	12,300
Total general taxes	$ 62,792	$ 53,481	$ 56,049
PROVISION FOR INCOME TAXES:			
Currently payable (receivable)-			
Federal	$ 29,862	$ (15,687)	$ 55,731
State	10,363	(245)	13,809
	40,225	(15,932)	69,540
Deferred, net-			
Federal	50,817	54,252	88,758
State	5,657	10,348	27,108
	56,474	64,600	115,866
Investment tax credit amortization	(1,587)	(2,228)	(3,551)
Total provision for income taxes	$ 95,112	$ 46,440	$ 181,855
INCOME STATEMENT CLASSIFICATION OF PROVISION FOR INCOME TAXES:			
Operating income	$ 89,425	$ 41,839	$ 171,496
Other income	5,687	4,601	10,359
Total provision for income taxes	$ 95,112	$ 46,440	$ 181,855
RECONCILIATION OF FEDERAL INCOME TAX EXPENSE AT STATUTORY RATE TO TOTAL PROVISION FOR INCOME TAXES:			
Book income before provision for income taxes	$ 206,751	$ 114,457	$ 433,749
Federal income tax expense at statutory rate	$ 72,363	$ 40,060	$ 151,812
Increases (reductions) in taxes resulting from-			
Amortization of investment tax credits	(1,587)	(2,228)	(3,551)
Depreciation	4,485	3,315	7,154
State income tax, net of federal benefit	10,413	7,178	27,111
Other, net	9,438	(1,885)	(671)
Total provision for income taxes	$ 95,112	$ 46,440	$ 181,855
ACCUMULATED DEFERRED INCOME TAXES AT DECEMBER 31:			
Property basis differences	$ 386,071	$ 371,811	$ 297,983
Nuclear decommissioning	27,123	34,663	44,775
Deferred sale and leaseback costs	(17,836)	(16,651)	(16,451)
Purchase accounting basis difference	(1,253)	(1,253)	(1,253)
Sale of generation assets	(15,614)	(17,861)	(17,861)
Regulatory transition charge	213,665	197,729	224,117
Provision for rate refund	-	-	(29,370)
Customer receivables for future income taxes	(27,239)	(4,519)	(5,336)
Oyster Creek securitization	184,245	193,558	202,448
Other comprehensive income	(38,353)	(32,998)	-
Employee benefits	1,652	(29,129)	-
Other	(66,720)	(55,142)	(7,331)
Net deferred income tax liability	$ 645,741	$ 640,208	$ 691,721

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

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. ORGANIZATION AND BASIS OF PRESENTATION:

The consolidated financial statements include JCP&L (Company) and its wholly owned subsidiaries. The Company is a wholly owned subsidiary of FirstEnergy. FirstEnergy also holds directly all of the issued and outstanding common shares of its other principal electric utility operating subsidiaries, including OE, CEI, TE, ATSI, Met-Ed and Penelec.

The Company follows GAAP and complies with the regulations, orders, policies and practices prescribed by the SEC, NJBPU and the FERC. The preparation of financial statements in conformity with GAAP requires management to make periodic estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses and the disclosure of contingent assets and liabilities. Actual results could differ from these estimates. Expenses (including transmission and congestion charges) were reclassified among purchased power, other operating costs and amortization of regulatory assets to conform with the current year presentation of generation commodity costs.

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

Certain prior year amounts have been reclassified to conform to the current year presentation. Revenue amounts related to transmission activities previously recorded as wholesale electric sales revenues were reclassified as transmission revenues. Expenses (including transmission and congestion charges) were reclassified among purchased power, other operating costs and amortization of regulatory assets to conform to the current year presentation. These reclassifications did not change previously reported results in 2003 and 2002.

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

The Company accounts for the effects of regulation through the application of SFAS 71 to its operating utilities when its 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.

Regulatory Assets-

The Company recognizes, as regulatory assets, costs which the FERC and the 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 Company's regulatory plan. The Company continues to bill and collect cost-based rates for its transmission and distribution services, which remain regulated; accordingly, it is appropriate that the Company continue the application of SFAS 71 to those operations.

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

	2004	2003
	(In millions)	
Regulatory transition charge	$ 2,215	$ 2,457
Societal benefits charge	51	82
Property losses and unrecovered plant costs	50	70
Liabilities to customers - income taxes	(58)	–
Employee postretirement benefit costs	27	30
Loss on reacquired debt	18	15
Spent fuel disposal costs	(1)	3
Component removal costs	(150)	(150)
Other	25	51
Total	$ 2,177	$ 2,558

Regulatory transition charges as of December 31, 2004 include $1.2 billion for the deferral of above-market costs from power supplied by NUGs. These costs are being recovered through BGS and MTC revenues.

Accounting for Generation Operations-

The application of SFAS 71 was discontinued in 1999 with respect to the Company's generation operations. The Company subsequently divested substantially all of its generating assets. The SEC's interpretive guidance and EITF 97-4 regarding asset impairment measurement, provides that any supplemental regulated cash flows such as a CTC should be excluded from the cash flows of assets in a portion of the business not subject to regulatory accounting practices. If those assets are impaired, a regulatory asset should be established if the costs are recoverable through regulatory cash flows. Net assets included in utility plant relating to operations for which the application of SFAS 71 was discontinued were $39 million as of December 31, 2004.

(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 Company's principal business is providing electric service to customers in New Jersey. The Company's 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 Company accrues the estimated unbilled amount receivable as revenue and reverses the related prior period estimate.

Receivables from customers include sales to residential, commercial and industrial customers and sales to wholesale customers. There was no material concentration of receivables as of December 31, 2004 or 2003, with respect to any particular segment of the Company's customers. Total customer receivables were $201 million (billed – $122 million and unbilled – $79 million) and $198 million (billed – $119 million and unbilled – $79 million) as of December 31, 2004 and 2003, respectively.

(D) PROPERTY, PLANT AND EQUIPMENT-

As a result of the Company's acquisition by FirstEnergy, a portion of the Company's property, plant and equipment was adjusted to reflect fair value. The majority of the Company's property, plant and equipment is reflected at original cost since such assets remain subject to rate regulation on a historical cost basis. In addition to its wholly owned facilities, the Company holds a 50% ownership interest in Yards Creek Pumped Storage Facility, and its net book value was approximately $19.2 million as of December 31, 2004. The costs of normal maintenance, repairs and minor replacements are expensed as incurred. The Company's accounting policy for planned major maintenance projects is to recognize liabilities as they are incurred.

The Company provides for depreciation on a straight-line basis at various rates over the estimated lives of property included in plant in service. The annualized composite rate was approximately 2.1% in 2004, 2.8% in 2003, and 3.5% in 2002. The reduced depreciation rates in 2004 and 2003 reflect reductions from the NJBPU August 2003 rate decision.

(E) ASSET IMPAIRMENTS-

Long-Lived Assets

The Company 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, the Company evaluates its goodwill for impairment at least annually and would make such an evaluation more frequently if indicators of impairment should 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, the Company 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. The Company's 2004 annual review was completed in the third quarter of 2004 with no impairment indicated. The forecasts used in the Company's evaluation of goodwill reflect operations consistent with its general business assumptions. Unanticipated changes in those assumptions could have a significant effect on the Company's future evaluations of goodwill. As of December 31, 2004, the Company had recorded goodwill of $2.0 billion related to the merger. In 2004, the Company adjusted goodwill for interest received on a pre-merger income tax refund and for the reversal of tax valuation allowances related to income tax benefits realized attributable to prior period capital loss carryforwards that were offset by capital gains generated in 2004.

Investments

The Company periodically evaluates for impairment investments that include available-for-sale securities held by their nuclear decommissioning trusts. In accordance with SFAS 115, securities classified as available-for-sale are evaluated to determine whether a decline in fair value below the cost basis is other than temporary. If the decline in fair value is determined to be other than temporary, the cost basis of the security is written down to fair value. The Company considers, among other factors, the length of time and the extent to which the security's fair value has been less than cost and the near-term financial prospects of the security issuer when evaluating investments for impairment. The fair value and unrealized gains and losses of the Company's investments are disclosed in Note 4.

(F) COMPREHENSIVE INCOME-

Comprehensive income includes net income as reported on the Consolidated Statements of Income and all other changes in common stockholder's equity except those resulting from transactions with FirstEnergy and preferred stockholders. As of December 31, 2004, accumulated other comprehensive loss consisted of unrealized losses on derivative instrument hedges of $2 million and a minimum liability for unfunded retirement benefits of $53 million. As of December 31, 2003, accumulated other comprehensive loss consisted of unrealized losses on derivative instrument hedges of $4 million and a minimum liability for unfunded retirement benefits of $48 million.

(G) INCOME TAXES-

Details of the total provision for income taxes are shown on the Consolidated Statements of Taxes. The Company records income taxes in accordance with the liability method of accounting. Deferred income taxes reflect the net tax effect of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used 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 carry forward 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. The Company is included in FirstEnergy's consolidated federal income tax return. The consolidated tax liability is allocated on a "stand-alone" company basis, with the Company recognizing the tax benefit for any tax losses or credits it contributes to the consolidated return.

(H) TRANSACTIONS WITH AFFILIATED COMPANIES-

Operating revenues, operating expenses and other income included transactions with affiliated companies, primarily FESC, GPUS and FES. GPUS (until it ceased operations in mid-2003) and FESC have provided legal, accounting, financial and other services to the Company. The Company also entered into sale and purchase transactions with affiliates (Met-Ed and Penelec) during the period. Through the BGS auction process, FES is a supplier of power to the Company. The primary affiliated companies transactions are as follows:

	2004	2003	2002
		(In millions)	
Operating Revenues:			
Wholesale sales–affiliated companies	$49	$ 36	$ 18
Operating Expenses:			
Service Company support services	95	101	140
Power purchased from other affiliates	–	–	26
Power purchased from FES	71	55	18

FirstEnergy does not bill directly or allocate any of its costs to any subsidiary company. Costs are allocated to the Company from FESC, a subsidiary of FirstEnergy and a "mutual service company" as defined in Rule 93 of PUHCA. The majority of costs are directly billed or assigned at no more than cost as determined by PUHCA Rule 91. The remaining costs are for services that are provided on behalf of more than one company, or costs that cannot be precisely identified and are allocated using formulas that are filed annually with the SEC on Form U-13-60. The current allocation or assignment formulas used and their bases include multiple factor formulas: each company's proportionate amount of FirstEnergy's aggregate direct payroll, number of employees, asset balances, revenues, number of customers, other factors and specific departmental charge ratios. Management believes that these allocation methods are reasonable. Intercompany transactions with FirstEnergy and its other subsidiaries are generally settled under commercial terms within thirty days, except for a net $48 million receivable from affiliates for OPEB obligations.

3. PENSION AND OTHER POSTRETIREMENT BENEFIT PLANS

FirstEnergy provides noncontributory defined benefit pension plans that cover substantially all of the Company's employees. The trusteed plans provide defined benefits based on years of service and compensation levels. The Company's funding policy is based on actuarial computations using the projected unit credit method. In the third quarter of 2004, FirstEnergy made a $500 million voluntary contribution to its pension plan (the Company's share was $62 million). Prior to this contribution, projections indicated that cash contributions of approximately $600 million would have been required during the 2006 to 2007 time period under minimum funding requirements established by the IRS. The election to pre-fund the plan is expected to eliminate that funding requirement. Since the contribution is deductible for tax purposes, the after-tax cash impact of the voluntary contribution is approximately $300 million (the Company's share was $37 million).

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

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

Unless otherwise indicated, the following tables provide information applicable to FirstEnergy's pension and OPEB plans.

Obligations and Funded Status As of December 31	Pension Benefits 2004	Pension Benefits 2003	Other Benefits 2004	Other Benefits 2003
	(In millions)			
Change in benefit obligation				
Benefit obligation as of January 1	$ 4,162	$ 3,866	$ 2,368	$ 2,077
Service cost	77	66	36	43
Interest cost	252	253	112	136
Plan participants' contributions	–	–	14	6
Plan amendments	–	–	(281)	(123)
Actuarial (gain) loss	134	222	(211)	323
Benefits paid	(261)	(245)	(108)	(94)
Benefit obligation as of December 31	$ 4,364	$ 4,162	$ 1,930	$ 2,368
Change in fair value of plan assets				
Fair value of plan assets as of January 1	$ 3,315	$ 2,889	$ 537	$ 473
Actual return on plan assets	415	671	57	88
Company contribution	500	–	64	68
Plan participants' contribution	–	–	14	2
Benefits paid	(261)	(245)	(108)	(94)
Fair value of plan assets as of December 31	$ 3,969	$ 3,315	$ 564	$ 537
Funded status	$ (395)	$ (847)	$ (1,366)	$ (1,831)
Unrecognized net actuarial loss	885	919	730	994
Unrecognized prior service cost (benefit)	63	72	(378)	(221)
Unrecognized net transition obligation	–	–	–	83
Net asset (liability) recognized	$ 553	$ 144	$ (1,014)	$ (975)
Amounts Recognized in the Consolidated Balance Sheets As of December 31				
Accrued benefit cost	$ (14)	$ (438)	$ (1,014)	$ (975)
Intangible assets	63	72	–	–
Accumulated other comprehensive loss	504	510	–	–
Net amount recognized	$ 553	$ 144	$ (1,014)	$ (975)
Company's share of net amount recognized	$ 68	$ 13	$ (79)	$ (89)
Increase (decrease) in minimum liability included in other comprehensive income (net of tax)	$ (4)	$ (145)	–	–
Assumptions Used to Determine Benefit Obligations As of December 31				
Discount rate	6.00%	6.25%	6.00%	6.25%
Rate of compensation increase	3.50%	3.50%		
Allocation of Plan Assets As of December 31				
Asset Category				
Equity securities	68%	70%	74%	71%
Debt securities	29	27	25	22
Real estate	2	2	–	–
Cash	1	1	1	7
Total	100%	100%	100%	100%

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

Components of Net Periodic Benefit Costs	Pension Benefits 2004	2003	2002	Other Benefits 2004	2003	2002
			(In millions)			
Service cost	$ 77	$ 66	$ 59	$ 36	$ 43	$ 29
Interest cost	252	253	249	112	137	114
Expected return on plan assets	(286)	(248)	(346)	(44)	(43)	(52)
Amortization of prior service cost	9	9	9	(40)	(9)	3
Amortization of transition obligation (asset)	-	-	-	-	9	9
Recognized net actuarial loss	39	62	-	39	40	11
Net periodic cost (income)	$ 91	$ 142	$ (29)	$ 103	$ 177	$ 114
Company's share of net periodic cost (income)	$ 7	$ 12	$ (20)	$ 5	$ 12	$ 5

Weighted-Average Assumptions Used to Determine Net Periodic Benefit Cost for Years Ended December 31	Pension Benefits 2004	2003	2002	Other Benefits 2004	2003	2002
Discount rate	6.25%	6.75%	7.25%	6.25%	6.75%	7.25%
Expected long-term return on plan assets	9.00%	9.00%	10.25%	9.00%	9.00%	10.25%
Rate of compensation increase	3.50%	3.50%	4.00%			

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

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

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

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

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

Pursuant to FSP 106-1 issued January 12, 2004, FirstEnergy began accounting for the effects of the Medicare Act effective January 1, 2004 because of a plan amendment during the quarter, which required remeasurement of the plan's obligations. The plan amendment, which increases cost-sharing by employees and retirees effective January 1, 2005, reduced the Company's postretirement benefit costs by $2 million during 2004.

Consistent with the guidance in FSP 106-2 issued on May 19, 2004, FirstEnergy recognized a reduction of $318 million in the accumulated postretirement benefit obligation as a result of the federal subsidy provided under the Medicare Act related to benefits for past service. This reduction was accounted for as an actuarial gain in 2004 pursuant to FSP 106-2. The subsidy reduced the Company's net periodic postretirement benefit costs by $5 million during 2004.

As a result of its voluntary contribution and the increased market value of pension plan assets, the Company reduced its accrued benefit cost as of December 31, 2004 by $46 million. As prescribed by SFAS 87, the Company increased its additional minimum liability by $9 million, offset by a charge to OCI. The balance in AOCL of $53 million (net of $37 million in deferred taxes) will reverse in future periods to the extent the fair value of trust assets exceeds the accumulated benefit obligation.

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

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

4. FAIR VALUE OF FINANCIAL INSTRUMENTS:

Long-term Debt and Other Long-term Obligations-

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

	2004		2003	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	(In millions)			
Long-term debt	$1,264	$1,252	$1,273	$1,190

The fair values of long-term debt 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 Company's ratings.

Investments-

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

	2004		2003	
	Carrying Value	Fair Value	Carrying Value	Fair Value
		(In millions)		
Debt securities:[1]				
–Government obligations	$ 208	$ 208	$ 200	$ 200
–Corporate debt securities	11	11	13	13
	219	219	213	213
Equity securities[1]	80	80	70	70
	$ 299	$ 299	$ 283	$ 283

[1] Includes nuclear decommissioning and nuclear fuel disposal trust investments.

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 Company has no securities held for trading purposes. The following table summarizes the amortized cost basis, gross unrealized gains and losses and fair values for decommissioning trust investments as of December 31:

	2004				2003			
	Cost Basis	Unrealized Gains	Unrealized Losses	Fair Value	Cost Basis	Unrealized Gains	Unrealized Losses	Fair Value
				(In millions)				
Debt securities	$ 55	$ 3	$ –	$ 58	$ 53	$ 4	$ –	$ 57
Equity securities	72	10	2	80	54	15	–	69
	$ 127	$ 13	$ 2	$ 138	$ 107	$ 19	$ –	$ 126

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

	2004	2003	2002
		(In millions)	
Proceeds from sales	$119	$ 70	$44
Gross realized gains	15	1	–
Gross realized losses	1	–	–
Interest and dividend income	4	4	4

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

	Less Than 12 Months		12 Months or More		Total	
	Fair Value	Unrealized Losses	Fair Value	Unrealized Losses	Fair Value	Unrealized Losses
	(In millions)					
Debt securities	$ 3	$ –	$ 5	$ –	$ 8	$ –
Equity securities	16	2	–	–	16	2
	$ 19	$ 2	$ 5	$ –	$ 24	$ 2

The Company periodically evaluates the securities held by its nuclear decommissioning trusts for other-than-temporary impairment. The Company 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 an impairment is other than temporary. The Company's decommissioning trusts are subject to regulatory accounting in accordance with SFAS 71. Net unrealized gains and losses are recorded as regulatory liabilities or assets since the difference between investments held in trust and the decommissioning liabilities are recovered from or refunded to customers.

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

5. LEASES:

Consistent with regulatory treatment, the rentals for capital and operating leases are charged to operating expenses on the Consolidated Statements of Income. The Company's most significant operating lease relates to the sale and leaseback of a portion of its ownership interest in the Merrill Creek Reservoir project. The interest element related to this lease was $1.4 million, $1.4 million, and $1.2 million for the years 2004, 2003 and 2002, respectively.

As of December 31, 2004, the future minimum lease payments on the Company's Merrill Creek operating lease, net of reimbursements from subleases, are: $1.7 million, $1.6 million, $1.6 million, $1.6 million and $2.1 million for the years 2005 through 2009, respectively, and $53.0 million for the years thereafter. The Company is recovering its Merrill Creek lease payments, net of reimbursements, through its distribution rates.

6. VARIABLE INTEREST ENTITIES:

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

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

The Company has determined that for all but six of these entities, the Company has no variable interests in the entities or the entities are governmental or not-for-profit organizations not within the scope of FIN 46R. The Company may hold variable interests in the remaining six 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, the Company requests on a quarterly basis, the information necessary from these entities to determine whether they are VIEs or whether the Company is the primary beneficiary. The Company has been unable to obtain the requested information, which in most cases, was deemed by the requested entity to be proprietary. As such, the Company applied the scope exception that exempts enterprises unable to obtain the necessary information to evaluate entities under FIN 46R. The maximum exposure to loss from these entities results from increases in the variable pricing component under the contract terms and cannot be determined without the requested data. The purchased power costs from these entities during 2004, 2003 and 2002, were $129 million, $115 million and $107 million, respectively.

7. REGULATORY MATTERS:

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

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

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

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

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

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

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

The Company 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 the Company's NUG committed supply currently being used to serve BGS customers pursuant to NJBPU order. The BGS auction for periods beginning June 1, 2004 was completed in February 2004 and new BGS tariffs reflecting the auction results became effective June 1, 2004. The NJBPU decision on the BGS post transition year three process was announced on October 22, 2004, approving with minor modifications the BGS procurement process filed by the Company and the other New Jersey electric distribution companies and authorizing the continued use of NUG committed supply to serve 300 MW of BGS load. The auction for the supply period beginning June 1, 2005 was completed in February 2005.

In accordance with an April 28, 2004 NJBPU order, the Company 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, the Company filed an updated TMI-2 decommissioning study (see Note 9 – Asset Retirement Obligation). This study resulted in an updated total decommissioning cost estimate of $729 million (in 2003 dollars) compared to the estimated $528 million (in 2003 dollars) from the prior 1995 decommissioning study. The Ratepayer Advocate filed comments on February 28, 2005. A schedule for further proceedings has not yet been set.

8. CAPITALIZATION:

(A) RETAINED EARNINGS-

In general, the Company's FMB indenture restricts the payment of dividends or distributions on or with respect to the Company's common stock to amounts credited to earned surplus since the date of its indenture. As of December 31, 2004, the Company had retained earnings available to pay common stock dividends of $41.5 million, net of amounts restricted under the Company's FMB indenture.

(B) PREFERRED AND PREFERENCE STOCK-

Preferred stock may be redeemed by the Company, in whole or in part, with 30-90 days' notice.

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

Securitized Transition Bonds

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

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

Bondable transition property represents the irrevocable right of a utility company to charge, collect and receive from its customers, through a non-bypassable TBC, the principal amount and interest on the transition bonds and other fees and expenses associated with their issuance. The Company, 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. The Company is entitled to a quarterly servicing fee of $100,000 that is payable from TBC collections.

Other Long-term Debt

The Company's FMB indenture, which secures all of the Company's FMBs, serves as a direct first mortgage lien on substantially all of the Company's property and franchises, other than specifically excepted property.

The Company has various debt covenants under its financing arrangements. The most restrictive of these relate to the nonpayment of interest and/or principal on debt, which could trigger a default. Cross-default provisions also exist between FirstEnergy and the Company.

Based on the amount of bonds authenticated by the Trustee through December 31, 2004, the Company's annual sinking fund requirements for all bonds issued under the mortgage amount to $24 million. The Company expects to fulfill its sinking fund obligation by providing refundable bonds to the Trustee.

Sinking fund requirements for FMBs and maturing long-term debt for the next five years are:

	(In millions)
2005	$ 17
2006	208
2007	18
2008	19
2009	25

9. ASSET RETIREMENT OBLIGATION:

In January 2003, the Company implemented SFAS 143, which provides accounting standards for retirement obligations associated with tangible long-lived assets. This statement 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 asset retirement liability 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.

The Company identified applicable legal obligations as defined under the new standard for nuclear power plant decommissioning. The ARO liability as of the date of adoption of SFAS 143 was $103.9 million, including accumulated accretion for the period from the date the liability was incurred to the date of adoption. As of December 31, 2002, the Company recognized decommissioning liabilities of $129.9 million. The Company expects substantially all nuclear decommissioning costs to be recoverable through regulated rates. Therefore, a regulatory liability of $26 million was recognized upon adoption of SFAS 143. The ARO includes the Company's obligation for the nuclear decommissioning of. The Company's share of the obligation to decommission TMI-2 was developed based on a site-specific study performed by an independent engineer. The Company utilized an expected cash flow approach to measure the fair value of the nuclear decommissioning ARO. The Company maintains nuclear decommissioning trust funds that are legally restricted for purposes of settling the nuclear decommissioning ARO. As of December 31, 2004, the fair value of the decommissioning trust assets was $138 million.

In the third quarter of 2004, the Company revised the ARO associated with TMI-2 as the result of a recently completed study and the anticipated operating license extension for TMI-1. The abandoned TMI-2 is adjacent to TMI-1 and the units are expected to be decommissioned concurrently. The net decrease in the Company's TMI-2 ARO liability and corresponding regulatory asset was $43 million.

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

Reconciliation	2004	2003
	(In millions)	
Beginning balance as of January 1	$ 110	$ 104
Accretion	5	6
Revision in estimated cash flows	(42)	–
Ending balance as of December 31	$ 73	$ 110

The following table provides the year-end balance of the ARO related to nuclear decommissioning for 2002, as if SFAS 143 had been adopted on January 1, 2002.

Adjusted ARO Reconciliation	2002
	(In millions)
Beginning balance as of January 1	$ 98
Accretion	6
Ending balance as of December 31	$ 104

10. SHORT-TERM BORROWINGS:

The Company may borrow from its affiliates on a short-term basis. As of December 31, 2004, the Company had total short-term borrowings outstanding of $248.5 million from its affiliates with an interest rate of 2.0%

11. 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. Based on its present ownership interest in TMI-2, the Company is exempt from any potential assessment under the industry retrospective rating plan.

The Company is also insured as to its interest in TMI-2 under a policy issued to the operating company for the plant. Under this policy, $150 million is provided for property damage and decontamination and decommissioning costs. Under this policy, the Company can be assessed a maximum of approximately $0.2 million for incidents at any covered nuclear facility occurring during a policy year which are in excess of accumulated funds available to the insurer for paying losses.

The Company intends to maintain insurance against nuclear risks as described above as long as it is available. To the extent that property damage, decontamination, decommissioning, repair and replacement costs and other such costs arising from a nuclear incident at TMI-2 exceed the policy limits of the insurance in effect with respect to that plant, to the extent a nuclear incident is determined not to be covered by the Company's insurance policies, or to the extent such insurance becomes unavailable in the future, the Company would remain at risk for such costs.

(B) ENVIRONMENTAL MATTERS-

The Company has been named as a PRP at waste disposal sites which may require cleanup under the Comprehensive Environmental Response, Compensation and Liability Act of 1980. Allegations of disposal of hazardous substances at historical sites and the liability involved are often unsubstantiated and subject to dispute; however, federal law provides that all PRPs for a particular site are liable on a joint and several basis. Therefore, environmental liabilities that are considered probable have been recognized on the Consolidated Balance Sheets, based on estimates of the total costs of cleanup, the Company's proportionate responsibility for such costs and the financial ability of other nonaffiliated entities to pay. In addition, the Company has accrued liabilities for environmental remediation of former manufactured gas plants in New Jersey; those costs are being recovered by the Company through a non-bypassable SBC. The Company has accrued liabilities aggregating approximately $47 million as of December 31, 2004. The Company accrues environmental liabilities only when it concludes that it is probable that an obligation for such costs exists and can reasonably determine the amount of such costs. Unasserted claims are reflected in the Company's determination of environmental liabilities and are accrued in the period that they are both probable and reasonably estimable.

(C) OTHER LEGAL PROCEEDINGS-

Power Outages and Related Litigation

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

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

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

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 instituted against the Companies. In particular, if FirstEnergy or its subsidiaries were ultimately determined to have legal liability in connection with these proceedings, it could have a material adverse effect on FirstEnergy's or its subsidiaries' financial condition and results of operations.

Legal Matters

There are various lawsuits, claims (including claims for asbestos exposure) and proceedings related to the Company's normal business operations pending against the Company, the most significant of which are described herein.

12. NEW ACCOUNTING STANDARDS AND INTERPRETATIONS:

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

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

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

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

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

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

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

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

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

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

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

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

13. SUMMARY OF QUARTERLY FINANCIAL DATA (UNAUDITED):

Three Months Ended	March 31, 2004	June 30, 2004	September 30, 2004	December 31, 2004(a)
		(In millions)		
Operating Revenues	$ 498.1	$ 549.6	$ 706.6	$ 452.7
Operating Expenses and Taxes	466.1	494.7	634.5	427.8
Operating Income	32.0	54.9	72.1	24.9
Other Income	1.5	1.1	2.0	3.2
Net Interest Charges	20.1	19.2	21.8	18.9
Net Income	$ 13.4	$ 36.8	$ 52.3	$ 9.2
Earnings on Common Stock	$ 13.3	$ 36.7	$ 52.2	$ 8.9

Three Months Ended	March 31, 2003	June 30, 2003	September 30, 2003	December 31, 2003
		(In millions)		
Operating Revenues	$ 657.0	$ 542.8	$ 741.3	$ 418.6
Operating Expenses and Taxes	581.6	564.5	653.8	413.0
Operating Income (Loss)	75.4	(21.7)	87.5	5.6
Other Income	1.2	2.3	0.6	3.0
Net Interest Charges	22.5	22.4	20.5	20.4
Net Income (Loss)	$ 54.1	$ (41.8)	$ 67.6	$ (11.8)
Earnings (Loss) Applicable to Common Stock	$ 53.9	$ (41.4)	$ 67.4	$ (11.8)

(a) Net income for the quarter ended December 31, 2004 includes an adjustment relating to periods prior to October 1, 2004, that decreased amortization expense and increased regulatory assets by $3.8 million ($2.2 million after tax). The adjustment corrects the accumulated amortization of the MTC deferred balance due to a revised MTC Tariff that became effective on August 1, 2003. Management concluded that the adjustment was not material to the reported results of operations for any quarter of 2003 and 2004, nor was it material to the consolidated balance sheets and consolidated statements of cash flows for any of those quarters.

FirstEnergy

c/o FirstEnergy Corp.
76 South Main Street
Akron, Ohio 44308
(800) 736-3402

2004 Annual Report

ANNUAL REPORT 2004

Met-Ed

A FirstEnergy Company

METROPOLITAN EDISON COMPANY

2004 ANNUAL REPORT TO STOCKHOLDERS

Metropolitan Edison Company is a wholly owned electric utility subsidiary of FirstEnergy Corp. It engages in the distribution and sale of electric energy in eastern and south central Pennsylvania. The area it serves has a population of approximately 1.2 million.

Contents

GLOSSARY OF TERMS

The following abbreviations and acronyms are used in this report to identify Metropolitan Edison Company and its affiliates:

ATSI	American Transmission Systems, Inc., owns and operates transmission facilities
CEI	The Cleveland Electric Illuminating Company, an affiliated Ohio electric utility
Companies	OE, CEI, TE, Penn, JCP&L, Met-Ed and Penelec
FES	FirstEnergy Solutions Corp., provides energy-related products and services
FESC	FirstEnergy Service Company, provides legal, financial, and other corporate support services
FirstEnergy	FirstEnergy Corp., a registered public utility holding company
GPU	GPU, Inc., former parent of JCP&L, Met-Ed and Penelec, which merged with FirstEnergy on November 7, 2001
GPUS	GPU Service Company, previously provided corporate support services
JCP&L	Jersey Central Power & Light Company, an affiliated New Jersey electric utility
Met-Ed	Metropolitan Edison Company
MYR	MYR Group, Inc., a utility infrastructure construction service company
OE	Ohio Edison Company, an affiliated Ohio electric utility
Penelec	Pennsylvania Electric Company, an affiliated Pennsylvania electric utility
Penn	Pennsylvania Power Company, an affiliated Pennsylvania electric utility
TE	The Toledo Edison Company, an affiliated Ohio electric utility

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

ALJ	Administrative Law Judge
AOCL	Accumulated Other Comprehensive Loss
APB	Accounting Principles Board
APB 25	APB Opinion No. 25, "Accounting for Stock Issued to Employees"
ARO	Asset Retirement Obligation
CTC	Competitive Transition Charge
ECAR	East Central Area Reliability Coordination
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FIN	FASB Interpretation
FIN 46R	FIN 46 (revised December 2003), "Consolidation of Variable Interest Entities"
FMB	First Mortgage Bonds
FSP	FASB Staff Position
FSP EITF 03-1-1	FASB Staff Position No. EITF Issue 03-1-1, "Effective Date of Paragraphs 10-20 of EITF Issue No. 03-1, The Meaning of Other-Than-Temporary Impairment and Its Application to Certain Investments"
EITF 97-4	EITF Issue No. 97-4, "Deregulation of the Pricing of Electricity - Issues Related to the Application of FASB Statements No. 71 and 101"
FSP 106-1	FASB Staff Position No.106-1, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003"
FSP 106-2	FASB Staff Position No.106-2, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003"
FSP 109-1	FASB Staff Position No. 109-1, "Application of FASB Statement No. 109, Accounting for Income Taxes, to the Tax Deduction and Qualified Production Activities provided by the American Jobs Creation Act of 2004"
GAAP	Accounting Principles Generally Accepted in the United States
IRS	Internal Revenue Service
KWH	Kilowatt-hours
Medicare Act	Medicare Prescription Drug, Improvement and Modernization Act of 2003
MISO	Midwest Independent Transmission System Operator, Inc.
Moody's	Moody's Investors Service
NERC	North American Electric Reliability Council
NUG	Non-Utility Generation
OCI	Other Comprehensive Income
OPEB	Other Post-Employment Benefits
PJM	PJM Interconnection L. L. C.
PLR	Provider of Last Resort

GLOSSARY OF TERMS, Cont'd

PPUC	Pennsylvania Public Utility Commission
PRP	Potentially Responsible Party
PUCO	Public Utilities Commission of Ohio
PUHCA	Public Utility Holding Company Act
RTC	Regulatory Transition Charge
S&P	Standard & Poor's Ratings Service
SEC	United States Securities and Exchange Commission
SFAS	Statement of Financial Accounting Standards
SFAS 71	SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation"
SFAS 87	SFAS No. 87, "Employers' Accounting for Pensions"
SFAS 106	SFAS No. 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions"
SFAS 133	SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities"
SFAS 142	SFAS No. 142, "Goodwill and Other Intangible Assets"
SFAS 143	SFAS No. 143, "Accounting for Asset Retirement Obligations"
SFAS 144	SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets"
SPE	Special Purpose Entity
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 2004 consolidated financial statements.

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

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

Management's Report on Internal Control Over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rule 13a-15(f) of the Securities Exchange Act of 1934. Using the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in *Internal Control – Integrated Framework*, management conducted an evaluation of the effectiveness of the Company's internal control over financial reporting under the supervision of the chief executive officer and the chief financial officer. Based on that evaluation, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2004. Management's assessment of the effectiveness of the Company's internal control over financial reporting, as of December 31, 2004, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears on page 2.

Report of Independent Registered Public Accounting Firm

To the Stockholders and Board of
Directors of Metropolitan Edison Company:

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

Consolidated financial statements

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

As discussed in Note 2(G) to the consolidated financial statements, the Company changed its method of accounting for asset retirement obligations as of January 1, 2003. As discussed in Note 6 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 Report on Internal Control Over Financial Reporting, that the Company maintained effective internal control over financial reporting as of December 31, 2004 based on criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), is fairly stated, in all material respects, based on those criteria. Furthermore, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2004, based on criteria established in *Internal Control – Integrated Framework* issued by the COSO. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express opinions on management's assessment and on the effectiveness of the Company's internal control over financial reporting based on our audit. We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we consider necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

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

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

PricewaterhouseCoopers LLP
Cleveland, Ohio
March 7, 2005

METROPOLITAN EDISON COMPANY

SELECTED FINANCIAL DATA

	2004	2003	2002	Nov. 7 - Dec. 31, 2001	Jan. 1 - Nov. 6, 2001	2000
			(Dollars in thousands)			
Operating Revenues	$ 1,070,847	$ 969,788	$ 986,608	$ 143,760	$ 824,556	$ 842,333
Operating Income	$ 86,197	$ 83,938	$ 91,271	$ 17,367	$ 102,247	$ 135,211
Income Before Cumulative Effect Of Accounting Change	$ 66,955	$ 60,953	$ 63,224	$ 14,617	$ 62,381	$ 81,895
Net Income	$ 66,955	$ 61,170	$ 63,224	$ 14,617	$ 62,381	$ 81,895
Total Assets	$ 3,245,278	$ 3,473,987	$ 3,564,805	$ 3,607,187		$ 2,708,062
Capitalization as of December 31:						
Common Stockholder's Equity	$ 1,285,419	$ 1,292,667	$ 1,315,586	$ 1,288,953		$ 537,013
Company-Obligated Trust Preferred Securities	--	--	92,409	92,200		100,000
Long-Term Debt and Other Long-Term Obligations	701,736	636,301	538,790	583,077		496,860
Total Capitalization	$ 1,987,155	$ 1,928,968	$ 1,946,785	$ 1,964,230		$ 1,133,873
Capitalization Ratios:						
Common Stockholder's Equity	64.7%	67.0%	67.6%	65.6%		47.4%
Company-Obligated Trust Preferred Securities	--	--	4.7	4.7		8.8
Long-Term Debt and Other Long-Term Obligations	35.3	33.0	27.7	29.7		43.8
Total Capitalization	100.0%	100.0%	100.0%	100.0%		100.0%
Distribution Kilowatt-Hour Deliveries (Millions):						
Residential	5,071	4,900	4,738	793	3,712	4,377
Commercial	4,251	4,034	3,991	652	3,203	3,699
Industrial	4,042	4,047	3,972	662	3,506	4,412
Other	33	36	35	6	27	38
Total	13,397	13,017	12,736	2,113	10,448	12,526
Customers Served:						
Residential	464,287	455,073	448,334	442,763		436,573
Commercial	59,495	58,825	58,010	57,278		56,080
Industrial	1,868	1,906	1,936	1,961		1,967
Other	730	732	728	819		810
Total	526,380	516,536	509,008	502,821		495,430

METROPOLITAN EDISON COMPANY

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

This discussion includes forward-looking statements based on information currently available to management. Such statements are subject to certain risks and uncertainties. These statements typically contain, but are not limited to, the terms "anticipate," "potential," "expect," "believe," "estimate" and similar words. Actual results may differ materially due to the speed and nature of increased competition and deregulation in the electric utility industry, economic or weather conditions affecting future sales and margins, changes in markets for energy services, changing energy and commodity market prices, replacement power costs being higher than anticipated or inadequately hedged, maintenance costs being higher than anticipated, legislative and regulatory changes (including revised environmental requirements), adverse regulatory or legal decisions and outcomes (including revocation of necessary licenses or operating permits, fines or other enforcement actions and remedies) of governmental investigations, including by the Securities and Exchange Commission as disclosed in our Securities and Exchange Commission filings, the availability and cost of capital, our ability to experience growth in the distribution business, our ability to access the public securities and other capital markets, further investigation into the causes of the August 14, 2003, regional power outage and the outcome, cost and other effects of present and potential legal and administrative proceedings and claims related to the outage, the risks and other factors discussed from time to time in our Securities and Exchange Commission filings, and other similar factors. We expressly disclaim any current intention to update any forward-looking statements contained herein as a result of new information, future events, or otherwise.

Reclassifications

As discussed in Note 1 to the consolidated financial statements, certain prior year amounts have been reclassified to conform to the current year presentation. Revenue amounts related to transmission activities previously recorded as wholesale electric sales revenues were reclassified as transmission revenues. Expenses (including transmission and congestion charges) were reclassified among purchased power, other operating costs and amortization of regulatory assets to conform to the current year presentation. These reclassifications did not change previously reported net income in 2003 and 2002.

Results of Operations

Net income increased to $67 million in 2004, compared to $61 million in 2003, due to higher operating revenues partially offset by higher purchased power costs and other operating costs. Net income decreased to $61 million in 2003, compared to $63 million in 2002, due to lower operating revenues and increased operating expenses, including higher employee benefit costs and storm restoration expenses. These reductions to net income were partially offset by lower purchased power costs, principally due to reduced quantities of power purchased through two-party agreements. Net interest charges were lower in 2003 due to debt redemptions and the refinancing of higher-rate debt.

Operating revenues increased by $101 million in 2004, primarily as a result of increases of $31 million and $36 million in retail generation sales and distribution throughput revenues, respectively. The higher generation sales revenues reflect the effect of an 11.8% increase in sales volume partially offset by lower composite prices. The volume increase was due to 8.5% and 34.6% increases, respectively, in sales to the commercial and industrial sectors as a result of customers returning to us from alternate suppliers. Sales by alternative suppliers as a percent of total sales delivered in our franchise area decreased by 2.9 and 20.2 percentage points for commercial and industrial customers, respectively. Higher revenues of $36 million from electricity throughput in 2004 from 2003 were due to higher prices and a 2.9% increase in distribution deliveries. The higher volume reflected an increase in the retail customer base and an improving economy, partially offset by cooler weather in the summer months of 2004. The higher distribution prices were due to the PPUC Restructuring Settlement order (see Regulatory Matters) with a corresponding decrease in retail generation prices. Also contributing to the revenue increase was $34 million of PJM network transmission system revenue, Financial Transmission Rights (FTR)/Auction Revenue Rights (ARR), and PJM congestion credit revenues related to transmission transactions we assumed in 2004 due to a change in our power supply agreement with FES, which also increased transmission expenses by $51 million, as discussed below.

The significant decrease in customer shopping in 2004 reflects our low generation price as provider of last resort. Alternative suppliers have not been able to match that price by a sufficient margin to ensure profitability, particularly in the industrial sector.

Operating revenues decreased by $17 million in 2003, compared to 2002. The decrease in 2003 was the result of wholesale sales revenues decreasing $25 million principally due to a reduction in kilowatt-hour sales to affiliate companies and other wholesale customers. An increase in the number of commercial and industrial customers receiving their power from alternate suppliers also contributed to the decrease in operating revenues. Distribution deliveries benefited from higher demand by residential (3.4%), commercial (1.0%), and industrial (1.9%) customers due in large part to colder temperatures in early 2003, which were partially offset by milder summer weather.

Changes in kilowatt-hour sales by customer class are summarized in the following table:

Changes in Kilowatt-hour Sales	2004	2003
Increase (Decrease)		
Electric Generation:		
Retail	11.8 %	1.2 %
Wholesale	209.1 %	(100.0)%
Total Electric Generation Sales	12.0 %	(6.1)%
Distribution Deliveries:		
Residential	3.5 %	3.4 %
Commercial	5.4 %	1.0 %
Industrial	(0.1)%	1.9 %
Total Distribution Deliveries	2.9 %	2.2 %

Operating Expenses and Taxes

Total operating expenses and taxes increased $99 million or 11.2% in 2004 and decreased $9 million in 2003:

Operating Expenses and Taxes - Changes	2004	2003
Increase (Decrease)		*(In millions)*
Purchased power costs	$ 64	$ (6)
Other operating costs	32	3
Provision for depreciation	(3)	(6)
Amortization of regulatory assets	8	-
General taxes	3	-
Income taxes	(5)	-
Total operating expenses and taxes	$ 99	$ (9)

Purchased power costs increased by $64 million in 2004, compared with 2003, primarily due to a 10.7% increase in kilowatt-hour purchases to meet higher retail generation sales requirements. Other operating costs increased by $32 million primarily due to PJM congestion and ancillary transmission expenses that we assumed in 2004 due to a change in our power supply agreement with FES. Depreciation expense decreased in 2004 due to fully depreciating the Energy Management System in 2003. Amortization of regulatory assets increased primarily due to higher regulatory asset amortization from higher revenue recovery of above market NUG costs in 2004. General taxes increased $3 million in 2004 primarily due to higher payroll and gross receipt taxes.

Total operating expenses and taxes decreased $9 million in 2003 compared to 2002. The majority of the decrease resulted from decreases in purchased power costs and depreciation expense, partially offset by higher other operating costs. Purchased power costs decreased by $6 million in 2003 because of reduced kilowatt hours required for customer needs during 2003, partially offset by slightly higher unit costs. The decrease in depreciation charges in 2003, compared to 2002, reflected a reduced depreciable asset base. Other operating costs increased in 2003 primarily due to increased costs to restore customer service resulting from significant storm activity and higher employee benefit costs.

Other Income

Other income increased $4 million in 2004, compared to 2003, due to a $2 million increase in the return on CTC stranded generation regulatory assets, and $2 million of interest income on federal income tax refunds.

Net Interest Charges

Interest on long-term debt increased by $4 million in 2004 as a result of increased debt outstanding from the issuance of $250 million of senior notes in the second quarter of 2004, partially offset by the retirement of $99 million of medium term notes and $100 million of preferred securities during the year. This increase was offset by a $4 million reduction in interest on company obligated manditorily redeemable preferred securities due to the redemption of all of the trust preferred securities in 2004.

Net interest charges decreased by $5 million in 2003, compared to 2002. The decrease reflects the refinancing of higher-cost debt in the first quarter of 2003.

Cumulative Effect of Accounting Change

Upon adoption of SFAS 143 in the first quarter of 2003, we recorded an after-tax credit to net income of $217,000. The cumulative effect adjustment for unrecognized depreciation, accretion offset by the reduction in the existing decommissioning liabilities and ceasing the accounting practice of depreciating non-regulated generation assets using a cost of removal component was a $371,000 increase to income, or $217,000 net of income taxes.

Capital Resources and Liquidity

Our cash requirements in 2004 for operating expenses, construction expenditures and scheduled debt maturities were met with a combination of cash from operations and funds from the capital markets. During 2005 and thereafter, we expect to meet our contractual obligations with a combination of cash from operations and funds from the capital markets.

Changes in Cash Position

As of December 31, 2004, we had $120,000 of cash and cash equivalents compared with $121,000 as of December 31, 2003. The major sources for changes in these balances are summarized below.

Cash Flows From Operating Activities

Cash flows provided from operating activities totaled $74 million in 2004, $132 million in 2003 and $102 million in 2002. The sources of these changes are as follows:

Operating Cash Flows	2004	2003	2002
		(In millions)	
Cash earnings [1]	$ 151	$ 180	$ 146
Pension trust contribution[2]	(23)	--	--
Working capital	(54)	(48)	(44)
Total	$ 74	$ 132	$ 102

[1] Cash earnings is a non-GAAP measure (see reconciliation below).
[2] Pension trust contribution net of $16 million of income tax benefits.

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	2004	2003	2002
		(In millions)	
Net Income (GAAP)	$ 67	$ 61	$ 63
Non-Cash Charges (Credits):			
Provision for depreciation	41	44	51
Amortization of regulatory assets	106	98	98
Deferred costs recoverable as regulatory assets	(66)	(71)	(86)
Deferred income taxes and investment tax credits	3	46	23
Other non-cash expenses	--	2	(3)
Cash earnings (Non-GAAP)	**$ 151**	**$ 180**	**$ 146**

Net cash provided from operating activities decreased $58 million during 2004, compared with 2003. The decrease consisted of lower cash earnings of $29 million, a $23 million after-tax voluntary pension trust contribution in 2004, and a $6 million decrease from changes in working capital. The decrease in cash earnings reflects changes in deferred income tax expense partially offset by other changes as described under "Results of Operations". The decrease in working capital was principally due to changes in receivables partially offset by increases in accounts payable balances. Net cash from operating activities increased by $30 million in 2003 compared to 2002 due to a $34 million increase in cash earnings partially offset by a $4 million decrease in working capital. The increase in cash earnings reflects changes in deferred income tax expense; the working capital decrease primarily reflected changes in receivables partially offset by changes in accrued tax balances.

Cash Flows From Financing Activities

In 2004, net cash provided from financing activities was $11 million, including $247 million in proceeds from the issuance of unsecured senior notes during the first quarter of 2004, and $15 million in short-term borrowings. The new financing was partially offset by the redemption of $100 million of unsecured subordinated debentures, $90 million of redeemed first mortgage bonds, redemption of $6 million of other unsecured obligations, and $55 million of common stock dividend payments.

In 2003, net cash used for financing activities of $88 million reflects redemptions of long-term debt of $260 million, repayment of $23 million of short-term borrowings, and $52 million of common stock dividend payments to FirstEnergy, partially offset by $248 million in proceeds from the issuance of secured notes. In 2002, net cash used for financing activities of $54 million reflects redemption of $60 million debt and $60 million of common stock dividend payments to FirstEnergy, partially offset by $50 million in proceeds from the issuance of secured notes, and a $16 million increase in short-term borrowings.

The following table provides details regarding new issues and redemptions during each year:

Securities Issued or Redeemed	2004	2003	2002
New Issues			
Secured notes	$ –	$ 248	$ 50
Unsecured notes	247	–	–
Redemptions			
First Mortgage Bonds	$ 90	$ 260	$ 60
Subordinated Debentures	100	–	–
Other – Cowanesque	6	–	–
	$ 196	$ 260	$ 60
Short-term Borrowings, net source /(use) of cash	$ 15	$ (23)	$ 16

In March 2004, we completed a receivables financing arrangement that provides borrowings of up to $80 million. The borrowing rate is based on bank commercial paper rates. We are required to pay an annual facility fee of 0.30% on the entire finance limit. The facility was undrawn as of December 31, 2004 and matures on March 29, 2005. We plan to renew the agreement.

We have $80 million of short-term indebtedness at the end of 2004, compared to $65 million at the end of 2003. We have obtained authorization from the SEC to incur short-term debt up to $250 million (including the utility money pool). Under the terms of our senior note indenture, we are no longer permitted to issue FMB so long as senior notes are outstanding. These receivables financing arrangements are expected to be renewed prior to expiration.

We have the ability to borrow from our regulated affiliates and FirstEnergy to meet our short-term working capital requirements. FESC administers this money pool and tracks surplus funds of FirstEnergy and its regulated subsidiaries, as well as proceeds available from bank borrowings. Companies receiving a loan under the money pool agreements must repay the principal amount of such 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 the pool and is based on the average cost of funds available through the pool. The average interest rate for borrowings under these arrangements in 2004 was 1.43%.

Our access to capital markets and costs of financing are dependent on the ratings of our securities and that of FirstEnergy. On August 26, 2004, S&P lowered its rating on certain of our Senior Notes to BBB- from BBB. The rationale for the ratings change was that our senior secured notes, in aggregate, now comprise greater than 80% of our total debt outstanding. According to the terms of the senior note indenture, once the 80% threshold is reached, the collateral mortgage bond security falls away and all senior secured notes that were secured by our senior note indenture become unsecured. The one notch lower rating reflects this loss of collateral security. The BBB senior secured rating on our first mortgage bonds remained unchanged.

The following table shows the securities ratings as of December 31, 2004. The ratings outlook from the ratings agencies on all securities is stable.

Ratings of Securities

	Securities	S&P	Moody's	Fitch
FirstEnergy	Senior unsecured	BB+	Baa3	BBB-
Met-Ed	Senior secured	BBB	Baa1	BBB+
	Senior unsecured	BBB-	Baa2	BBB

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

Cash Flows From Investing Activities

Cash used for investing activities totaled $85 million in 2004 and $60 million in 2003. The increase resulted from a $10 million increase in property additions, $1 million of additional loans to associated companies, and a $9 million capital transfer from FESC.

Cash used for investing activities totaled $60 million in 2003 and $58 million in 2002. The net cash flows used for investing activities during 2003 resulted from property additions, decommissioning trust investments, and loans to associated companies. Cash used for investing activities during 2002 were for property additions primarily to support our energy delivery operations and decommissioning trust investments.

Our capital spending for the period 2005 through 2007 is expected to be about $205 million for property additions and energy delivery related improvements, of which approximately $67 million applies to 2005.

Contractual Obligations

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

Contractual Obligations	Total	2005	2006-2007	2008-2009	Thereafter
			(In millions)		
Long-term debt [3]	$ 730	$ 30	$ 151	$ 7	$ 542
Short-term borrowings	80	80	--	--	--
Operating leases [1]	49	1	3	3	42
Purchases [2]	2,922	309	804	745	1,064
Total	$ 3,781	$ 420	$ 958	$ 755	$ 1,648

(1) Operating lease payments are net of reimbursements from sublessees (see Note 5 – Leases)
(2) Power purchases under contracts with fixed or minimum quantities and approximate timing
(3) Amounts reflected do not include interest on long-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 management oversight to risk management activities throughout our Company. They are responsible for promoting the effective design and implementation of sound risk management programs. They also oversee compliance with corporate risk management policies and established risk management practices.

Commodity Price Risk

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

Increase In the Fair Value of Derivative Contracts	**Non-Hedge**	**Hedge**	**Total**
	(In millions)		
Change in the fair value of commodity derivative contracts			
Outstanding net asset as of January 1, 2004	$ 31	$ –	$ 31
New contract value when entered	–	–	–
Additions/Increase in value of existing contracts	1	–	1
Change in techniques/assumptions	–	–	–
Settled contracts	–	–	–
Net Assets - Derivatives Contracts as of December 31, 2004 [1]	$ 32	$ –	$ 32
Impact of Changes In Commodity Derivative Contracts [2]			
Income Statement Effects (Pre-Tax)	$ 1	$ –	$ 1
Balance Sheet Effects:			
OCI (Pre-Tax)	$ –	$ –	$ –

(1) Includes $31 million in non-hedge commodity derivative contracts, which are offset by a regulatory liability.
(2) Represents the increase in value of existing contracts, settled contracts and changes in techniques/ assumptions.

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

	Non-Hedge	**Hedge**	**Total**
	(In millions)		
Current-			
Other Assets	$ –	$ –	$ –
Other liabilities	–	–	–
Non-Current-			
Other Deferred Charges	32	–	32
Other noncurrent liabilities	–	–	–
Net assets	$ 32	$ –	$ 32

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

Source of Information – Fair Value by Contract Year	**2005**	**2006**	**2007**	**2008**	**Thereafter**	**Total**
			(In millions)			
Other external sources [1]	10	4	–	–	–	14
Prices based on models	–	–	6	5	7	18
Total[2]	$ 10	$ 4	$ 6	$ 5	$ 7	$ 32

(1) Broker quote sheets.
(2) Includes $31 million from an embedded option that is offset by a regulatory liability and does not affect earnings.

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

Interest Rate Risk

We are subject to the inherent interest rate risks related to refinancing maturing debt by issuing new debt securities. Our exposure to fluctuations in market interest rates is reduced since our debt has fixed interest rates, as noted in the following table.

Comparison of Carrying Value to Fair Value

Year of Maturity	2005	2006	2007	2008	2009	There-after	Total	Fair Value
				(Dollars in millions)				
Assets								
Investments Other Than Cash and Cash Equivalents-								
Fixed Income						$ 83	$ 83	$ 83
Average interest rate						4.7%	4.7%	
Liabilities								
Long-term Debt and Other Long-Term Obligations:								
Fixed rate	$ 30	$ 101	$ 50	$ 7		$ 542	$ 730	$ 731
Average interest rate	6.8%	5.7%	5.9%	6.0%		4.9%	5.2%	
Short-term Borrowings	80						$ 80	$ 80
Average interest rate	2.0%						2.0%	

Equity Price Risk

Included in nuclear decommissioning trusts are marketable equity securities carried at their current fair value of approximately $134 million and $114 million as of December 31, 2004 and 2003, respectively. A hypothetical 10% decrease in prices quoted by stock exchanges would result in a $13 million reduction in fair value as of December 31, 2004 (see Note 4 – Fair Value of Financial Instruments).

Outlook

Beginning in 1999, all of our customers were able to select alternative energy suppliers. We continue to deliver power to homes and businesses through our existing distribution system, which remains regulated. The PPUC authorized our rate restructuring plan, establishing separate charges for transmission, distribution, generation and stranded cost recovery, which is recovered through a CTC. Customers electing to obtain power from an alternative supplier have their bills reduced based on the regulated generation component, and the customers receive a generation charge from the alternative supplier. We have a continuing responsibility referred to as our PLR obligation to provide power to those customers not choosing to receive power from an alternative energy supplier, subject to certain limits.

We recognize, as regulatory assets, costs which the PPUC and the FERC 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 when incurred. All regulatory assets are expected to be recovered under the provisions of the regulatory plan. Our regulatory assets totaled $693 million and $1 billion as of December 31, 2004 and December 31, 2003, respectively.

Regulatory Matters

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

On January 12, 2005, we filed, before the PPUC, a request for deferral of transmission-related costs beginning January 1, 2005 estimated to be approximately $4 million per month. Various parties have intervened in this case.

See Note 7 to the consolidated financial statements for a more complete and detailed discussion of regulatory matters in Pennsylvania.

Environmental Matters

We have been named as a PRP 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 be held liable on a joint and several basis. Therefore, environmental liabilities that are considered probable have been recognized on the Consolidated Balance Sheet as of December 31, 2004, based on estimates of the total costs of cleanup, our proportionate responsibility for such costs and the financial ability of other nonaffiliated entities to pay. We have accrued liabilities aggregating approximately $26,000 as of December 31, 2004.

Legal Matters

Various lawsuits, claims (including claims for asbestos exposure) and proceedings related to our normal business operations are pending against us, the most significant of which are described above.

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.

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 should 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 were indicated, we would recognize a loss – calculated as the difference between the implied fair value of our goodwill and the carrying value of the goodwill. Our annual review was completed in the third quarter of 2004, with no impairment of goodwill indicated. The forecasts used in our evaluation 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. In the year ended December 31, 2004, we adjusted goodwill related to interest received on a pre-merger income tax refund and for the reversal of tax valuation allowances related to income tax benefits realized attributable to prior period capital loss carryforwards that were used to offset capital gains generated in 2004. As of December 31, 2004, we had recorded goodwill of approximately $870 million.

Regulatory Accounting

We are subject to regulation that sets the prices (rates) it is permitted to charge its customers based on the costs that the regulatory agencies determine the company is 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 rate-making process results in the recording of regulatory assets based on anticipated future cash inflows. We regularly review these assets to assess their ultimate recoverability within the approved regulatory guidelines. Impairment risk associated with these assets relates to potentially adverse legislative, judicial or regulatory actions in the future.

Revenue Recognition

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

Pension and Other Postretirement Benefits Accounting

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

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

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

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

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

In the third quarter of 2004, FirstEnergy made a $500 million voluntary contribution to its pension plan (our share was $39 million). Prior to this contribution, projections indicated that cash contributions of approximately $600 million would have been required during the 2006 to 2007 time period under minimum funding requirements established by the IRS. FirstEnergy's election to pre-fund the plan is expected to eliminate that funding requirement.

As a result of our voluntary contribution and the increased market value of pension plan assets, we reduced our accrued benefit cost as of December 31, 2004 by $23 million. As prescribed by SFAS 87, we increased our additional minimum liability by $16 million, offset by a charge to OCI. The balance in AOCL of $42 million (net of $30 million in deferred taxes) will reverse in future periods to the extent the fair value of trust assets exceeds the accumulated benefit obligation.

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

Long-Lived Assets

In accordance with SFAS No. 144, we periodically evaluate our long-lived assets to determine whether conditions exist that would indicate that the carrying value of an asset might not be fully recoverable. The accounting standard requires that if the sum of future cash flows (undiscounted) expected to result from an asset is less than the carrying value of the asset, an asset impairment must be recognized in the financial statements. If impairment has occurred, we recognize a loss – calculated as the difference between the carrying value and the estimated fair value of the asset (discounted future net cash flows).

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

Nuclear Decommissioning

In accordance with SFAS 143, we recognize an ARO for the future decommissioning of TMI-2. The ARO liability represents an estimate of the fair value of our current obligation related to nuclear decommissioning and the retirement of other assets. A fair value measurement inherently involves uncertainty in the amount and timing of settlement of the liability. We used an expected cash flow approach to measure the fair value of the nuclear decommissioning ARO. This approach applies probability weighting to discounted future cash flow scenarios that reflect a range of possible outcomes. The scenarios consider settlement of the ARO at the expiration of the nuclear power plant's current license and settlement based on an extended license term.

New Accounting Standards and Interpretations Adopted

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

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

METROPOLITAN EDISON COMPANY

CONSOLIDATED STATEMENTS OF INCOME

	2004	2003	2002
		(In thousands)	
OPERATING REVENUES (Note 2(I))	$ 1,070,847	$ 969,788	$ 986,608
OPERATING EXPENSES AND TAXES:			
Fuel and purchased power (Note 2(I))	554,988	491,346	497,163
Other operating costs (Note 2(I))	190,401	157,986	155,137
Provision for depreciation	41,161	44,160	50,838
Amortization of regulatory assets	105,675	97,784	97,957
General taxes	70,457	67,207	66,795
Income taxes	21,968	27,367	27,447
Total operating expenses and taxes	984,650	885,850	895,337
OPERATING INCOME	86,197	83,938	91,271
OTHER INCOME (NET OF INCOME TAXES)	25,537	21,782	21,742
NET INTEREST CHARGES:			
Interest on long-term debt	40,630	36,657	40,774
Allowance for borrowed funds used during construction	(278)	(323)	(470)
Deferred interest	--	(1,187)	(710)
Other interest expense	4,427	5,841	2,636
Subsidiary's preferred stock dividend requirements	--	3,779	7,559
Net interest charges	44,779	44,767	49,789
INCOME BEFORE CUMULATIVE EFFECT OF ACCOUNTING CHANGE	66,955	60,953	63,224
Cumulative effect of accounting change (net of income taxes of $154,000) (Note 2(G))	--	217	--
NET INCOME	$ 66,955	$ 61,170	$ 63,224

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

METROPOLITAN EDISON COMPANY

CONSOLIDATED BALANCE SHEETS

As of December 31,	2004	2003
	(In thousands)	
ASSETS		
UTILITY PLANT:		
In service	$ 1,800,569	$ 1,838,567
Less-Accumulated provision for depreciation	709,895	772,123
	1,090,674	1,066,444
Construction work in progress	21,735	21,980
	1,112,409	1,088,424
OTHER PROPERTY AND INVESTMENTS:		
Nuclear plant decommissioning trusts	216,951	192,409
Long-term notes receivable from associated companies	10,453	9,892
Other	34,767	34,922
	262,171	237,223
CURRENT ASSETS:		
Cash and cash equivalents	120	121
Notes receivable from associated companies	18,769	10,467
Receivables-		
Customers (less accumulated provisions of $4,578,000 and $4,943,000 respectively, for uncollectible accounts)	119,858	118,933
Associated companies	118,245	45,934
Other (less accumulated provisions of $68,000 for uncollectible accounts in 2003)	15,493	22,750
Prepayments and other	11,057	6,600
	283,542	204,805
DEFERRED CHARGES:		
Regulatory assets	693,133	1,028,432
Goodwill	869,585	884,279
Other	24,438	30,824
	1,587,156	1,943,535
	$ 3,245,278	$ 3,473,987
CAPITALIZATION AND LIABILITIES		
CAPITALIZATION(See Consolidated Statements of Capitalization):		
Common stockholder's equity	$ 1,285,419	$ 1,292,667
Long-term debt and other long-term obligations	701,736	636,301
	1,987,155	1,928,968
CURRENT LIABILITIES:		
Currently payable long-term debt	30,435	40,469
Short-term borrowings (Note 10)-		
Associated companies	80,090	65,335
Accounts payable-		
Associated companies	88,879	45,459
Other	26,097	33,878
Accrued taxes	11,957	8,762
Accrued interest	11,618	11,848
Other	23,076	22,162
	272,152	227,913
NONCURRENT LIABILITIES:		
Accumulated deferred income taxes	305,389	297,140
Accumulated deferred investment tax credits	10,868	11,696
Power purchase contract loss liability	349,980	584,340
Nuclear fuel disposal costs	38,408	37,936
Asset retirement obligation	132,887	210,178
Retirement benefits	82,218	105,552
Other	66,221	70,264
	985,971	1,317,106
COMMITMENTS AND CONTINGENCIES (Notes 5 and 11)		
	$ 3,245,278	$ 3,473,987

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

METROPOLITAN EDISON COMPANY

CONSOLIDATED STATEMENTS OF CAPITALIZATION

As of December 31,	2004	2003
	(Dollars in thousands, except per share amounts)	
COMMON STOCKHOLDER'S EQUITY:		
Common stock, without par value, authorized 900,000 shares 859,500 shares outstanding	$ 1,289,943	$ 1,298,130
Accumulated other comprehensive loss (Note 2(F))	(43,490)	(32,474)
Retained earnings (Note 8(A))	38,966	27,011
Total common stockholder's equity	1,285,419	1,292,667
LONG-TERM DEBT (Note 8(C)):		
First mortgage bonds:		
6.340% due 2004	--	40,000
6.770% due 2005	30,000	30,000
6.360% due 2006	--	17,000
6.400% due 2006	--	33,000
6.000% due 2008	7,830	8,265
6.100% due 2021	28,500	28,500
5.950% due 2027	13,690	13,690
Total first mortgage bonds	80,020	170,455
Secured notes:		
5.720% due 2006	--	100,000
5.930% due 2007	--	50,000
4.450% due 2010	--	100,000
4.950% due 2013	--	150,000
Total secured notes	--	400,000
Unsecured notes:		
5.720% due 2006	100,000	--
5.930% due 2007	50,000	--
4.450% due 2010	100,000	--
4.950% due 2013	150,000	--
4.875% due 2014	250,000	--
7.690% due 2039	--	5,936
7.350% due 2039	--	95,711
Total unsecured notes	650,000	101,647
Net unamortized premium on debt	2,151	4,668
Long-term debt due within one year	(30,435)	(40,469)
Total long-term debt	701,736	636,301
TOTAL CAPITALIZATION	$ 1,987,155	$ 1,928,968

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

METROPOLITAN EDISON COMPANY

CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDER'S EQUITY

	Comprehensive Income	Common Stock Number of Shares	Common Stock Carrying Value	Accumulated Other Comprehensive Income (Loss)	Retained Earnings
		(Dollars in thousands)			
Balance, January 1, 2002		859,500	$ 1,274,325	$ 11	$ 14,617
Net income	$ 63,224				63,224
Net unrealized gain on investment	17			17	
Net unrealized loss on derivative instruments	(67)			(67)	
Comprehensive income	$ 63,174				
Cash dividends on common stock					(60,000)
Purchase accounting fair value adjustment			23,459		
Balance, December 31, 2002		859,500	1,297,784	(39)	17,841
Net income	$ 61,170				61,170
Net unrealized gain on investments	2			2	
Net unrealized gain on derivative instruments	78			78	
Minimum liability for unfunded retirement benefits, net of $(23,062,000) of income taxes	(32,515)			(32,515)	
Comprehensive income	$ 28,735				
Cash dividends on common stock					(52,000)
Purchase accounting fair value adjustment			346		
Balance, December 31, 2003		859,500	1,298,130	(32,474)	27,011
Net income	$ 66,955				66,955
Net unrealized loss on investments	(26)			(26)	
Net unrealized loss on derivative instruments, net of $(1,279,000) of income taxes	(1,819)			(1,819)	
Minimum liability for unfunded retirement benefits, net of $(6,502,000) of income taxes	(9,171)			(9,171)	
Comprehensive income	$ 55,939				
Cash dividends on common stock					(55,000)
Purchase accounting fair value adjustment			(8,187)		
Balance, December 31, 2004		859,500	1,289,943	(43,490)	38,966

CONSOLIDATED STATEMENTS OF PREFERRED STOCK

	Subject to Mandatory Redemption Number of Shares	Subject to Mandatory Redemption Carrying Value
	(Dollars in thousands)	
Balance January 1, 2002	4,000,000	$ 92,200
Amortization of fair market value adjustment		209
Balance, December 31, 2002	4,000,000	$ 92,409
FIN 46 Deconsolidation 7.35% Series	(4,000,000)	(92,618)
Amortization of fair market value adjustment		209
Balance, December 31, 2003	–	–
Balance, December 31, 2004	–	$ –

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

METROPOLITAN EDISON COMPANY

CONSOLIDATED STATEMENTS OF CASH FLOWS

	2004	2003	2002
		(In thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net Income	$ 66,955	$ 61,170	$ 63,224
Adjustments to reconcile net income to net cash from operating activities:			
Provision for depreciation	41,161	44,160	50,838
Amortization of regulatory assets	105,675	97,784	97,957
Other amortization	--	--	(2,528)
Deferred costs recoverable as regulatory assets	(65,981)	(70,752)	(86,314)
Deferred income taxes and investment tax credits, net	18,495	45,832	22,564
Accrued retirement benefits obligations	(186)	(3,284)	63
Accrued compensation, net	584	5,531	(2,491)
Cumulative effect of accounting change (Note 2(G))	--	(371)	--
Pension trust contribution	(38,823)	--	--
Decrease (increase) in operating assets:			
Receivables	(65,979)	10,380	(24,672)
Prepayments and other current assets	(4,457)	3,131	2,508
Increase (decrease) in operating liabilities:			
Accounts payable	35,639	(20,988)	(18,657)
Accrued taxes	3,195	(7,334)	9,059
Accrued interest	(230)	(4,600)	(1,020)
Other	(22,222)	(28,171)	(8,657)
Net cash provided from operating activities	73,826	132,488	101,874
CASH FLOWS FROM FINANCING ACTIVITIES:			
New Financing-			
Long-term debt	247,606	247,696	49,750
Short-term borrowings, net	14,755	--	16,288
Redemptions and Repayments-			
Long-term debt	(196,371)	(260,466)	(60,000)
Short-term borrowings, net	--	(22,964)	--
Dividend Payments-			
Common stock	(55,000)	(52,000)	(60,000)
Net cash provided from (used for) financing activities	10,990	(87,734)	(53,962)
CASH FLOWS FROM INVESTING ACTIVITIES:			
Property additions	(52,979)	(43,558)	(44,533)
Contributions to decommissioning trusts	(9,483)	(9,483)	(12,644)
Loan payments to associated companies, net	(8,863)	(7,941)	--
Other	(13,492)	664	(324)
Net cash used for investing activities	(84,817)	(60,318)	(57,501)
Net decrease in cash and cash equivalents	(1)	(15,564)	(9,589)
Cash and cash equivalents at beginning of period	121	15,685	25,274
Cash and cash equivalents at end of period	$ 120	$ 121	$ 15,685
SUPPLEMENTAL CASH FLOWS INFORMATION:			
Cash Paid During the Year-			
Interest (net of amounts capitalized)	$ 43,733	$ 51,505	$ 46,266
Income taxes (refund)	$ 33,693	$ (25,085)	$ 34,385

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

METROPOLITAN EDISON COMPANY

CONSOLIDATED STATEMENTS OF TAXES

	2004	2003	2002
		(In thousands)	
GENERAL TAXES:			
State gross receipts *	$ 58,900	$ 53,462	$ 56,043
Real and personal property	1,490	2,510	1,384
Social security and unemployment	3,800	2,448	1
Other	6,267	8,787	9,367
Total general taxes	$ 70,457	$ 67,207	$ 66,795
PROVISION FOR INCOME TAXES:			
Currently payable-			
Federal	$ 12,679	$ (3,435)	$ 15,371
State	7,043	1,763	6,437
	19,722	(1,672)	21,808
Deferred, net-			
Federal	20,599	38,863	19,615
State	(1,276)	7,791	3,741
	19,323	46,654	23,356
Investment tax credit amortization	(828)	(822)	(792)
Total provision for income taxes	$ 38,217	$ 44,160	$ 44,372
INCOME STATEMENT CLASSIFICATION OF PROVISION FOR INCOME TAXES:			
Operating income	$ 21,968	$ 27,367	$ 27,447
Other income	16,249	16,639	16,925
Cumulative effect of accounting change	-	154	-
Total provision for income taxes	$ 38,217	$ 44,160	$ 44,372
RECONCILIATION OF FEDERAL INCOME TAX EXPENSE AT STATUTORY RATE TO TOTAL PROVISION FOR INCOME TAXES:			
Book income before provision for income taxes	$ 105,172	$ 105,330	$ 107,596
Federal income tax expense at statutory rate	$ 36,810	$ 36,866	$ 37,659
Increases (reductions) in taxes resulting from-			
Amortization of investment tax credits	(828)	(822)	(792)
Depreciation	2,662	1,736	1,362
State income tax, net of federal benefit	3,749	6,289	6,107
Other, net	(4,176)	91	36
Total provision for income taxes	$ 38,217	$ 44,160	$ 44,372
ACCUMULATED DEFERRED INCOME TAXES AT DECEMBER 31:			
Property basis differences	$ 257,880	$ 250,779	$ 217,351
Nuclear decommissioning	(4,755)	(6,405)	(4,247)
Deferred sale and leaseback costs	(11,149)	(10,986)	(11,366)
Non-utility generation costs	7,475	2,287	(4,832)
Purchase accounting basis difference	(642)	(642)	(642)
Sale of generation assets	(1,419)	(1,419)	(1,419)
Regulatory transition charge	95,056	88,020	88,315
Customer receivables for future income taxes	40,636	46,010	50,259
Other comprehensive income	(30,843)	(23,062)	-
Employee benefits	(5,289)	(17,252)	-
Other	(41,561)	(30,190)	(16,662)
Net deferred income tax liability	$ 305,389	$ 297,140	$ 316,757

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

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. ORGANIZATION AND BASIS OF PRESENTATION:

The consolidated financial statements include Met-Ed (Company) and its wholly owned subsidiaries. The Company is a wholly owned subsidiary of FirstEnergy. FirstEnergy also holds directly all of the issued and outstanding common shares of its other principal electric utility operating subsidiaries, including OE, CEI, TE, ATSI, JCP&L and Penelec.

The Company follows GAAP and complies with the regulations, orders, policies and practices prescribed by the SEC, PPUC and the FERC. The preparation of financial statements in conformity with GAAP requires management to make periodic estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses and the disclosure of contingent assets and liabilities. Actual results could differ from these estimates. Revenue amounts related to transmission activities previously recorded as wholesale electric sales revenues were reclassified as transmission revenues. Expenses (including transmission and congestion charges) were reclassified among purchased power, other operating costs and amortization of regulatory assets to conform with the current year presentation of generation commodity costs.

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

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

The Company accounts for the effects of regulation through the application of SFAS 71 to its operating utilities when its 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.

Regulatory Assets-

The Company recognizes, as regulatory assets, costs which the FERC and the PPUC 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 Company's regulatory plan. The Company continues to bill and collect cost-based rates for its transmission and distribution services, which remain regulated; accordingly, it is appropriate that the Company continue the application of SFAS 71 to those operations.

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

	2004	2003
	(In millions)	
Regulatory transition costs	$ 692	$ 926
Customer receivables for future income taxes	90	103
Nuclear decommissioning costs	(122)	(26)
Employee postretirement benefit costs	16	18
Loss on reacquired debt	17	8
Other	–	(1)
Total	$ 693	$ 1,028

Regulatory transition charges as of December 31, 2004 include $0.5 billion for the deferral of above-market costs from power supplied by NUGs. These costs are being recovered through CTC revenues. The regulatory asset for above-market NUG costs and a corresponding liability are adjusted to fair value at the end of each quarter.

Accounting for Generation Operations-

The application of SFAS 71 was discontinued in 1998 with respect to the Company's generation operations. The Company subsequently divested substantially all of its generating assets. The SEC's interpretive guidance and EITF 97-4 regarding asset impairment measurement provides that any supplemental regulated cash flows such as a CTC should be excluded from the cash flows of assets in a portion of the business not subject to regulatory accounting practices. If those assets are impaired, a regulatory asset should be established if the costs are recoverable through regulatory cash flows. Net assets included in utility plant relating to the operations for which the application of SFAS 71 was discontinued, were $13 million as of December 31, 2004.

(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 Company's principal business is providing electric service to customers in Pennsylvania. The Company's 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 Company accrues the estimated unbilled amount receivable as revenue and reverses the related prior period estimate.

Receivables from customers include sales to residential, commercial and industrial customers and sales to wholesale customers. There was no material concentration of receivables as of December 31, 2004 or 2003, with respect to any particular segment of the Company's customers. Total customer receivables were $120 million (billed – $74 million and unbilled – $46 million) and $119 million (billed – $70 million and unbilled – $49 million) as of December 31, 2004 and 2003, respectively.

(D) PROPERTY, PLANT AND EQUIPMENT-

As a result of the Company's acquisition by FirstEnergy in 2001, a portion of the Company's property, plant and equipment was adjusted to reflect fair value. The majority of the Company's property, plant and equipment continues to be reflected at original cost since such assets remain subject to rate regulation on a historical cost basis. The costs of normal maintenance, repairs and minor replacements are expensed as incurred. The Company's accounting policy for planned major maintenance projects is to recognize liabilities as they are incurred.

The Company provides for depreciation on a straight-line basis at various rates over the estimated lives of property included in plant in service. The annualized composite rate was approximately 2.4% in 2004, 2.6% in 2003 and 3.0% in 2002. The decrease in the composite depreciation rate reflects changes in the depreciable plant base due to assets with higher depreciation rates being fully depreciated since 2002.

(E) ASSET IMPAIRMENTS-

Long-Lived Assets

The Company 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, the Company evaluates its goodwill for impairment at least annually and would make such an evaluation more frequently if indicators of impairment should 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, the Company 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. The Company's 2004 annual review was completed in the third quarter of 2004 with no impairment indicated. The forecasts used in the Company's evaluations of goodwill reflect operations consistent with its general business assumptions. Unanticipated changes in those assumptions could have a significant effect on the Company's future evaluations of goodwill. As of December 31, 2004, the Company had $870 million of goodwill. In 2004, the Company adjusted goodwill for interest received on a pre-merger income tax refund and for the reversal of tax valuation allowances related to income tax benefits realized attributable to prior period capital loss carryforwards that were offset by capital gains generated in 2004.

Investments

The Company periodically evaluates for impairment investments that include 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. The Company considers, among other factors, the length of time and the extent to which the security's fair value has been less than cost and the near-term financial prospects of the security issuer when evaluating investments for impairment. The fair value and unrealized gains and losses of the Company's investments are disclosed in Note 4.

(F) COMPREHENSIVE INCOME-

Comprehensive income includes net income as reported on the Consolidated Statements of Income and all other changes in common stockholder's equity except those resulting from transactions with FirstEnergy. As of December 31, 2004 and December 31, 2003, accumulated other comprehensive loss consisted of a minimum liability for unfunded retirement benefits of $42 million and $33 million, respectively. As of December 31, 2004 accumulated other comprehensive loss also consisted of unrealized losses on derivative instrument hedges of $2 million.

(G) CUMULATIVE EFFECT OF ACCOUNTING CHANGE

As a result of adopting SFAS 143 in January 2003, asset retirement costs were recorded in the amount of $186 million as part of the carrying amount of the related long-lived asset, offset by accumulated depreciation of $186 million. The ARO liability on the date of adoption was $198 million, including accumulated accretion for the period from the date the liability was incurred to the date of adoption. 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 $371,000 increase to income, $217,000 net of tax in the year ended December 31, 2003. If SFAS 143 had been applied during 2002, the impact would not have been material to the Company's Consolidated Statements of Income.

(H) INCOME TAXES-

Details of the total provision for income taxes are shown on the Consolidated Statements of Taxes. The Company records income taxes in accordance with the liability method of accounting. Deferred income taxes reflect the net tax effect of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used 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. The Company is included in FirstEnergy's consolidated federal income tax return. The consolidated tax liability is allocated on a "stand-alone" company basis, with the Company recognizing the tax benefit for any tax losses or credits it contributes to the consolidated return.

(I) TRANSACTIONS WITH AFFILIATED COMPANIES-

Operating revenues, operating expenses and other income included transactions with affiliated companies, primarily FESC, GPUS and FES. GPUS (until it ceased operations in mid-2003) and FESC have provided legal, accounting, financial and other corporate support services to the Company. The Company also entered into sale and purchase transactions with affiliates (JCP&L and Penelec) during 2002. Effective September 1, 2002, the Company purchases a portion of its PLR responsibility from FES through a wholesale power sale agreement. The primary affiliated companies transactions are as follows:

	2004	2003	2002
		(In millions)	
Operating Revenues:			
Wholesale sales–affiliated companies	$ --	$ --	$ 19
Operating Expenses:			
Power purchased from FES	434	277	172
Service Company support services	46	50	68
Power purchased from other affiliates	--	2	10

FirstEnergy does not bill directly or allocate any of its costs to any subsidiary company. Costs are allocated to the Company from FESC, which is a subsidiary of FirstEnergy and a "mutual service company" as defined in Rule 93 of the PUHCA. The vast majority of costs are directly billed or assigned at no more than cost as determined by PUHCA Rule 91. The remaining costs are for services that are provided on behalf of more than one company, or costs that cannot be precisely identified and are allocated using formulas that are filed annually with the SEC on Form U-13-60. The current allocation or assignment formulas used and their bases include multiple factor formulas: each company's proportionate amount of FirstEnergy's aggregate direct payroll, number of employees, asset balances, revenues, number of customers, other factors and specific departmental charge ratios. Management believes that these allocation methods are reasonable. Intercompany transactions with FirstEnergy and its other subsidiaries are generally settled under commercial terms within thirty days, except for a net $33 million receivable from affiliates for OPEB obligations.

3. PENSION AND OTHER POSTRETIREMENT BENEFIT PLANS:

FirstEnergy provides noncontributory defined benefit pension plans that cover substantially all of the Company's employees. The trusteed plans provide defined benefits based on years of service and compensation levels. The Company's funding policy is based on actuarial computations using the projected unit credit method. In the third quarter of 2004, FirstEnergy made a $500 million voluntary contribution to its pension plan (the Company's share was $39 million). Prior to this contribution, projections indicated that cash contributions of approximately $600 million would have been required during the 2006 to 2007 time period under minimum funding requirements established by the IRS. The election to pre-fund the plan is expected to eliminate that funding requirement. Since the contribution is deductible for tax purposes, the after-tax cash impact of the voluntary contribution is approximately $300 million (the Company's share was $23 million).

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

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

Unless otherwise indicated, the following tables provide information applicable to FirstEnergy's pension and OPEB plans.

Obligations and Funded Status As of December 31	Pension Benefits 2004	Pension Benefits 2003	Other Benefits 2004	Other Benefits 2003
	(In millions)			
Change in benefit obligation				
Benefit obligation as of January 1	$ 4,162	$ 3,866	$ 2,368	$ 2,077
Service cost	77	66	36	43
Interest cost	252	253	112	136
Plan participants' contributions	–	–	14	6
Plan amendments	–	–	(281)	(123)
Actuarial (gain) loss	134	222	(211)	323
Benefits paid	(261)	(245)	(108)	(94)
Benefit obligation as of December 31	$ 4,364	$ 4,162	$ 1,930	$ 2,368
Change in fair value of plan assets				
Fair value of plan assets as of January 1	$ 3,315	$ 2,889	$ 537	$ 473
Actual return on plan assets	415	671	57	88
Company contribution	500	–	64	68
Plan participants' contribution	–	–	14	2
Benefits paid	(261)	(245)	(108)	(94)
Fair value of plan assets as of December 31	$ 3,969	$ 3,315	$ 564	$ 537
Funded status	$ (395)	$ (847)	$ (1,366)	$ (1,831)
Unrecognized net actuarial loss	885	919	730	994
Unrecognized prior service cost (benefit)	63	72	(378)	(221)
Unrecognized net transition obligation	–	–	–	83
Net asset (liability) recognized	$ 553	$ 144	$ (1,014)	$ (975)
Amounts Recognized in the Consolidated Balance Sheets As of December 31				
Accrued benefit cost	$ (14)	$ (438)	$ (1,014)	$ (975)
Intangible assets	63	72	–	–
Accumulated other comprehensive loss	504	510	–	–
Net amount recognized	$ 553	$ 144	$ (1,014)	$ (975)
Company's share of net amount recognized	$ 49	$ 10	$ (59)	$ (59)
Increase (decrease) in minimum liability included in other comprehensive income (net of tax)	$ (4)	$ (145)	–	–
Assumptions Used to Determine Benefit Obligations As of December 31				
Discount rate	6.00%	6.25%	6.00%	6.25%
Rate of compensation increase	3.50%	3.50%		
Allocation of Plan Assets As of December 31				
Asset Category				
Equity securities	68%	70%	74%	71%
Debt securities	29	27	25	22
Real estate	2	2	–	–
Cash	1	1	1	7
Total	100%	100%	100%	100%

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

	Pension Benefits			Other Benefits		
Components of Net Periodic Benefit Costs	2004	2003	2002	2004	2003	2002
			(In millions)			
Service cost	$ 77	$ 66	$ 59	$ 36	$ 43	$ 29
Interest cost	252	253	249	112	137	114
Expected return on plan assets	(286)	(248)	(346)	(44)	(43)	(52)
Amortization of prior service cost	9	9	9	(40)	(9)	3
Amortization of transition obligation (asset)	--	--	--	--	9	9
Recognized net actuarial loss	39	62	--	39	40	11
Net periodic cost (income)	$ 91	$ 142	$ (29)	$ 103	$ 177	$ 114
Company's share of net periodic cost (income)	$ --	$ 5	$ (11)	$ 3	$ 7	$ 3

Weighted-Average Assumptions Used to Determine Net Periodic Benefit Cost for Years Ended December 31	Pension Benefits			Other Benefits		
	2004	2003	2002	2004	2003	2002
Discount rate	6.25%	6.75%	7.25%	6.25%	6.75%	7.25%
Expected long-term return on plan assets	9.00%	9.00%	10.25%	9.00%	9.00%	10.25%
Rate of compensation increase	3.50%	3.50%	4.00%			

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

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

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

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

	1-Percentage-Point Increase	1-Percentage-Point Decrease
	(In millions)	
Effect on total of service and interest cost	$ 9	$ (16)
Effect on postretirement benefit obligation	$205	$(179)

Pursuant to FSP 106-1 issued January 12, 2004, FirstEnergy began accounting for the effects of the Medicare Act effective January 1, 2004 because of a plan amendment during the quarter, which required remeasurement of the plan's obligations. The plan amendment, which increases cost-sharing by employees and retirees effective January 1, 2005, reduced the Company's postretirement benefit costs by $2 million during 2004.

Consistent with the guidance in FSP 106-2 issued on May 19, 2004, FirstEnergy recognized a reduction of $318 million in the accumulated postretirement benefit obligation as a result of the federal subsidy provided under the Medicare Act related to benefits for past service. This reduction was accounted for as an actuarial gain in 2004 pursuant to FSP106-2. The subsidy reduced the Company's net periodic postretirement benefit costs by $4 million during 2004.

As a result of its voluntary contribution and the increased market value of pension plan assets, the Company reduced its accrued benefit cost as of December 31, 2004 by $23 million. As prescribed by SFAS 87, the Company increased its additional minimum liability by $16 million, offset by a charge to OCI. The balance in AOCL of $42 million (net of $30 million in deferred taxes) will reverse in future periods to the extent the fair value of trust assets exceeds the accumulated benefit obligation.

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

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

4. FAIR VALUE OF FINANCIAL INSTRUMENTS:

Long-term Debt and Other Long-term Obligations-

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

	2004		2003	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	(In millions)			
Long-term debt	$ 730	$ 731	$ 576	$ 593
Subordinated debentures to affiliated trusts	–	–	96	104
	$ 730	$ 731	$ 672	$ 697

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 Company's ratings.

Investments-

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

	2004		2003	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	(In millions)			
Debt securities:[1]				
-Government obligations	$ 78	$ 78	$ 72	$ 72
-Corporate debt securities	5	5	6	6
	83	83	78	78
Equity securities[1]	137	137	117	117
	$ 220	$ 220	$ 195	$ 195

[1] Includes nuclear decommissioning trust investments.

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 decommissioning trust investments, which are classified as available-for-sale securities. The Company has no securities held for trading purposes. The following table summarizes the amortized cost basis, gross unrealized gains and losses and fair values for decommissioning trust investments as of December 31:

	2004				2003			
	Cost Basis	Unrealized Gains	Unrealized Losses	Fair Value	Cost Basis	Unrealized Gains	Unrealized Losses	Fair Value
	(In millions)							
Debt securities	$ 80	$ 3	$ –	$ 83	$ 74	$ 4	$ –	$ 78
Equity securities	113	24	3	134	75	40	1	114
	$ 193	$ 27	$ 3	$ 217	$ 149	$ 44	$ 1	$ 192

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

	2004	2003	2002
	(In millions)		
Proceeds from sales	$179	$84	$65
Gross realized gains	30	2	1
Gross realized losses	1	1	1
Interest and dividend income	6	5	5

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

	Less Than 12 Months		12 Months or More		Total	
	Fair Value	Unrealized Losses	Fair Value	Unrealized Losses	Fair Value	Unrealized Losses
	(In millions)					
Debt securities	$ 10	$ –	$ 6	$ –	$ 16	$ --
Equity securities	21	3	1	–	22	3
	$ 31	$ 3	$ 7	$ –	38	$ 3

The Company periodically evaluates the securities held by its nuclear decommissioning trusts for other-than-temporary impairment. The Company 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 an impairment is other than temporary. The recovery of amounts contributed to the Company's decommissioning trusts are subject to regulatory accounting in accordance with SFAS 71. Net unrealized gains and losses are recorded as regulatory liabilities or assets since the difference between investments held in trust and the decommissioning liabilities are recovered from or refunded to customers.

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

5. LEASES:

Consistent with regulatory treatment, the rentals for capital and operating leases are charged to operating expenses on the Consolidated Statements of Income. The Company's most significant operating lease relates to the sale and leaseback of a portion of its ownership interest in the Merrill Creek Reservoir project. The interest element related to this lease was $1.6 million, $1.6 million and $0.2 million for the years 2004, 2003 and 2002.

As of December 31, 2004, the future minimum lease payments on the Company's Merrill Creek operating lease, net of reimbursements from sublessees, are: $1.5 million, $1.5 million, $1.5 million, $1.5 million and $1.9 million for the years 2005 through 2009, respectively, and $41.9 million for the years thereafter. The Company's Merrill Creek lease payments were offset against the actual net divestiture proceeds received from the 1999 sales of its generating assets.

6. VARIABLE INTEREST ENTITIES:

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

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

The Company has determined that for all but one of these entities, the Company has no variable interests in the entities or the entities are governmental or not-for-profit organizations not within the scope of FIN 46R. The Company may hold a variable interest in the remaining entity, which sells its output at variable price that correlates to some extent with the operating costs of the plant.

As required by FIN 46R, the Company requests on a quarterly basis, the information necessary from this entity to determine whether it is a VIE or whether the Company is the primary beneficiary. The Company has been unable to obtain the requested information, which was deemed by the requested entity to be proprietary. As such, the Company applied the scope exception that exempts enterprises unable to obtain the necessary information to evaluate entities under FIN 46R. The maximum exposure to loss from this entity results from increases in the variable pricing component under the contract terms and cannot be determined without the requested data. The purchased power costs from this entity during 2004, 2003 and 2002 were $54 million, $53 million and $53 million, respectively.

7. REGULATORY MATTERS:

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

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

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

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

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

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

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

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

On January 12, 2005, the Company filed, before the PPUC, a request for deferral of transmission-related costs beginning January 1, 2005 estimated to be approximately $4 million per month. Various parties have intervened in this case.

8. CAPITALIZATION:

(A) RETAINED EARNINGS-

In general, the Company's FMB indentures restrict the payment of dividends or distributions on or with respect to the Company's common stock to amounts credited to earned surplus since the date of its indenture. As of December 31, 2004, the Company had retained earnings available to pay common stock dividends of $35.6 million, net of amounts restricted under the Company's FMB indenture.

(B) PREFERRED AND PREFERENCE STOCK-

The Company's preferred stock authorization consists of 10 million shares without par value. No preferred shares are currently outstanding.

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

Subordinated Debentures to Affiliated Trust

The Company had formed a statutory business trust to sell preferred securities and invest the gross proceeds in subordinated debentures. Ownership of the Company's trust had been through a separate wholly owned limited partnership. In this transaction, the trust had invested the gross proceeds from the sale of its preferred securities in the preferred securities of the limited partnership, which in turn invested those proceeds in the 7.35% subordinated debentures of the Company. In June 2004, the Company extinguished the subordinated debentures held by its affiliated trust and redeemed all of the associated 7.35% preferred securities (aggregate value of $100 million).

Other Long-term Debt

The Company's FMB indenture, which secures all of the Company's FMBs, serve as a direct first mortgage lien on substantially all of the Company's property and franchises, other than specifically excepted property.

The Company has various debt covenants under its financing arrangements. The most restrictive of these relate to the nonpayment of interest and/or principal on debt, which could trigger a default. Cross-default provisions also exist between FirstEnergy and the Company.

Based on the amount of bonds authenticated by the Trustee through December 31, 2004 the Company's annual sinking fund requirements for all bonds issued under the mortgage amount to $6 million. The Company expects to fulfill its sinking fund obligation by providing refundable bonds to the Trustee.

Sinking fund requirements for FMBs and maturing long-term debt for the next five years are:

	(In millions)
2005	$ 30
2006	101
2007	50
2008	7
2009	--

The Company's obligations to repay certain pollution control revenue bonds are secured by several series of FMBs. Certain pollution control revenue bonds are entitled to the benefit of noncancelable municipal bond insurance policies of $42 million to pay principal of, or interest on, the pollution control revenue bonds.

9. ASSET RETIREMENT OBLIGATION-

In January 2003, the Company implemented SFAS 143, which provides accounting standards for retirement obligations associated with tangible long-lived assets. This statement 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 asset retirement liability 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.

The Company identified applicable legal obligations as defined under the new standard for nuclear power plant decommissioning. The ARO liability as of the date of adoption of SFAS 143 was $198 million, including accumulated accretion for the period from the date the liability was incurred to the date of adoption. As of December 31, 2002, the Company recognized decommissioning liabilities of $260 million. The Company expects substantially all nuclear decommissioning costs to be recoverable through regulated rates. Therefore, a regulatory liability of $61 million was recognized upon adoption of SFAS 143. The ARO includes the Company's obligation for nuclear decommissioning of TMI-2. The Company's share of the obligation to decommission TMI-2 was developed based on a site-specific study performed by an independent engineer. The Company utilized an expected cash flow approach to measure the fair value of the nuclear decommissioning ARO. The Company maintains nuclear decommissioning trust funds that are legally restricted for purposes of settling the nuclear decommissioning ARO. As of December 31, 2004, the fair value of the decommissioning trust assets was $217 million.

In the third quarter of 2004, the Company revised the ARO associated with TMI-2 as the result of a recently completed study and the anticipated operating license extension for TMI-1. The abandoned TMI-2 is adjacent to TMI-1 and the units are expected to be decommissioned concurrently. The net decrease in the Company's TMI-2 ARO liability and corresponding regulatory asset was $89 million.

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

ARO Reconciliation	2004	2003
	(In millions)	
Beginning balance as of January 1	$ 210	$ 198
Accretion	12	12
Revisions in estimated cash flows	(89)	--
Ending balance as of December 31	$ 133	$ 210

The following table provides the year-end balance of the ARO related to nuclear decommissioning for 2002, as if SFAS 143 had been adopted on January 1, 2002.

Adjusted ARO Reconciliation	2002
	(In millions)
Beginning balance as of January 1	$ 187
Accretion	11
Ending balance as of December 31	$ 198

10. SHORT-TERM BORROWINGS:

The Company may borrow from its affiliates on a short-term basis. As of December 31, 2004, the Company had total short-term borrowings of $80 million from its affiliates. The weighted average interest rates on short-term borrowings outstanding at December 31, 2004 and 2003 were 2.0% and 1.7%, respectively.

The Company has, through a separate wholly owned subsidiary, a receivables financing agreement under which the Company can borrow up to an aggregate of $80 million at rates based on certain bank commercial paper and is required to pay an annual facility fee of 0.30% on the entire finance limit. This financing agreement expires on March 29, 2005. These receivables financing arrangements are expected to be renewed prior to expiration.

11. 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. Based on its present ownership interest in TMI-2, the Company is exempt from any potential assessment under the industry retrospective rating plan.

The Company is also insured as to its interest in TMI-2 under a policy issued to the operating company for the plant. Under this policy, $150 million is provided for property damage and decontamination and decommissioning costs. Under this policy, the Company can be assessed a maximum of approximately $0.4 million for incidents at any covered nuclear facility occurring during a policy year which are in excess of accumulated funds available to the insurer for paying losses.

The Company intends to maintain insurance against nuclear risks as described above as long as it is available. To the extent that property damage, decontamination, decommissioning, repair and replacement costs and other such costs arising from a nuclear incident at TMI-2 exceed the policy limits of the insurance in effect with respect to that plant, to the extent a nuclear incident is determined not to be covered by the Company's insurance policies, or to the extent such insurance becomes unavailable in the future, the Company would remain at risk for such costs.

(B) ENVIRONMENTAL MATTERS-

The Company has been named as a PRP at waste disposal sites which may require cleanup under the Comprehensive Environmental Response, Compensation and Liability Act of 1980. Allegations of disposal of hazardous substances at historical sites and the liability involved are often unsubstantiated and subject to dispute; however, federal law provides that all PRPs for a particular site are liable on a joint and several basis. Therefore, environmental liabilities that are considered probable have been recognized on the Consolidated Balance Sheets, based on estimates of the total costs of cleanup, the Company's proportionate responsibility for such costs and the financial ability of other nonaffiliated entities to pay. The Company has accrued liabilities aggregating approximately $26,000 as of December 31, 2004. The Company accrues environmental liabilities only when it concludes that it is probable that an obligation for such costs exists and can reasonably determine the amount of such costs. Unasserted claims are reflected in the Company's determination of environmental liabilities and are accrued in the period that they are both probable and reasonably estimable.

(C) OTHER LEGAL PROCEEDINGS-

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

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 instituted against the Companies. In particular, if FirstEnergy or its subsidiaries were ultimately determined to have legal liability in connection with these proceedings, it could have a material adverse effect on FirstEnergy's or its subsidiaries' financial condition and results of operations.

Legal Matters

There are various lawsuits, claims (including claims for asbestos exposure) and proceedings related to the Company's normal business operations, pending against the Company, the most significant of which are described above.

12. NEW ACCOUNTING STANDARDS AND INTERPRETATIONS:

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

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

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

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

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

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

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

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

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

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

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

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

13. SUMMARY OF QUARTERLY FINANCIAL DATA (UNAUDITED):

The following summarizes certain consolidated operating results by quarter for 2004 and 2003.

Three Months Ended	March 31, 2004	June 30, 2004	Sept. 30, 2004	Dec. 31, 2004
		(In millions)		
Operating Revenues	$ 260.9	$ 242.0	$ 285.4	$ 282.5
Operating Expenses and Taxes	237.6	228.5	265.1	253.4
Operating Income	23.3	13.5	20.3	29.1
Other Income	5.5	6.2	6.9	7.0
Net Interest Charges	10.8	13.0	10.1	10.9
Net Income	$ 18.0	$ 6.7	$ 17.1	$ 25.2

Three Months Ended	March 31, 2003	June 30, 2003	Sept. 30, 2003	Dec. 31, 2003
		(In millions)		
Operating Revenues	$ 251.2	$ 217.7	$ 261.2	$ 239.7
Operating Expenses and Taxes	227.2	199.2	242.0	217.5
Operating Income	24.0	18.5	19.2	22.2
Other Income	5.2	5.3	5.2	6.1
Net Interest Charges	12.4	11.0	10.7	10.7
Income Before Cumulative Effect of Accounting Change	16.8	12.8	13.7	17.6
Cumulative Effect of Accounting Change (Net of Income Taxes)	0.2	--	--	--
Net Income	$ 17.0	$ 12.8	$ 13.7	$ 17.6

FirstEnergy

c/o FirstEnergy Corp.
76 South Main Street
Akron, Ohio 44308
(800) 736-3402

2004 Annual Report

ANNUAL REPORT 2004

Penelec
A FirstEnergy Company

PENNSYLVANIA ELECTRIC COMPANY

2004 ANNUAL REPORT TO STOCKHOLDERS

Pennsylvania Electric Company is a wholly owned electric utility operating subsidiary of FirstEnergy Corp. It engages in the distribution and sale of electric energy in an area of approximately 17,600 square miles in western Pennsylvania. It also engages in the sale, purchase and interchange of electric energy with other electric companies. The area it serves has a population of approximately 1.7 million. The Company is a lessee of the property of the Waverly Electric Light & Power Company, which provides electric energy service in Waverly, New York and vicinity.

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GLOSSARY OF TERMS

The following abbreviations and acronyms are used in this report to identify Pennsylvania Electric Company and its affiliates:

ATSI	American Transmission Systems, Inc., owns and operates transmission facilities
Companies	OE, CEI, TE, Penn, JCP&L, Met-Ed and Penelec
FES	FirstEnergy Solutions Corp., provides energy-related products and services
FESC	FirstEnergy Service Company, provides legal, financial, and other corporate support services
FirstEnergy	FirstEnergy Corp., a registered public utility holding company
GPU	GPU, Inc., former parent of JCP&L, Met-Ed and Penelec, which merged with FirstEnergy on November 7, 2001
GPUS	GPU Service Company, previously provided corporate support services
JCP&L	Jersey Central Power & Light Company, an affiliated New Jersey electric utility
Met-Ed	Metropolitan Edison Company, an affiliated Pennsylvania electric utility
OE	Ohio Edison Company, an affiliated Ohio electric utility
Penelec	Pennsylvania Electric Company
Penn	Pennsylvania Power Company, an affiliated Pennsylvania electric utility
TE	The Toledo Edison Company, an affiliated Ohio electric utility

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

ALJ	Administrative Law Judge
AOCL	Accumulated Other Comprehensive Loss
APB	Accounting Principles Board
APB 29	APB Opinion No. 29, "Accounting for Accounting Research Bulletin"
ARB	Accounting Research Bulletin
ARB 43	ARB No. 43, "Restatement and Revision of Accounting Research Bulletin"
ARO	Asset Retirement Obligation
CTC	Competitive Transition Charge
ECAR	East Central Area Reliability Coordination Agreement
EITF	Emerging Issues Task Force
EITF 03-1	EITF Issue No. 03-1, "The Meaning of Other-Than-Temporary and Its Application to Certain Investments"
EITF 03-16	EITF Issue No. 03-16, "Accounting for Investments in Limited Liability Companies"
EITF 97-4	EITF Issue No. 97-4 "Deregulation of the Pricing of Electricity - Issues Related to the Application of FASB Statements No. 71 and 101"
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FIN 46R	FASB Interpretation No. 46 (revised December 2003), "Consolidation of Variable Interest Entities"
FMB	First Mortgage Bonds
FSP EITF 03-1-1	FASB Staff Position No. EITF Issue 03-1-1, "Effective Date of Paragraphs 10-20 of EITF Issue No. 03-1, The Meaning of Other-Than-Temporary Impairment and Its Application to Certain Investments"
FSP 106-1	FASB Staff Position No.106-1, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003"
FSP 106-2	FASB Staff Position No.106-2, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003"
FSP 109-1	FASB Staff Position No. 109-1, "Application of FASB Statement No. 109, Accounting for Income Taxes, to the Tax Deduction and Qualified Production Activities provided by the American Jobs Creation Act of 2004"
GAAP	Accounting Principles Generally Accepted in the United States
IRS	Internal Revenue Service
Medicare Act	Medicare Prescription Drug, Improvement and Modernization Act of 2003
MISO	Midwest Independent Transmission System Operator, Inc.
Moody's	Moody's Investors Service
NERC	North American Electric Reliability Council
NUG	Non-Utility Generation
OCI	Other Comprehensive Income
OPEB	Other Post-Employment Benefits
PJM	PJM Interconnection L. L. C.
PLR	Provider of Last Resort

GLOSSARY OF TERMS, Cont'd

PPUC	Pennsylvania Public Utility Commission
PRP	Potentially Responsible Party
PUCO	Public Utilities Commission of Ohio
PUHCA	Public Utility Holding Company Act
S&P	Standard & Poor's Ratings Service
SEC	United States Securities and Exchange Commission
SFAS	Statement of Financial Accounting Standards
SFAS 71	SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation"
SFAS 87	SFAS No. 87, "Employers' Accounting for Pensions"
SFAS 101	SFAS No. 101, "Accounting for Discontinuation of Application of SFAS 71"
SFAS 106	SFAS No. 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions"
SFAS 115	SFAS No. 115, "Accounting for Certain Investments in Debt and Equity Securities"
SFAS 133	SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities"
SFAS 142	SFAS No. 142, "Goodwill and Other Intangible Assets"
SFAS 143	SFAS No. 143, "Accounting for Asset Retirement Obligations"
SFAS 144	SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets"
SPE	Special Purpose Entity
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 2004 consolidated financial statements.

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

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

Management's Report on Internal Control Over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rule 13a-15(f) of the Securities Exchange Act of 1934. Using the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in *Internal Control – Integrated Framework*, management conducted an evaluation of the effectiveness of the Company's internal control over financial reporting under the supervision of the chief executive officer and the chief financial officer. Based on that evaluation, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2004. Management's assessment of the effectiveness of the Company's internal control over financial reporting, as of December 31, 2004, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears on page 2.

Report of Independent Registered Public Accounting Firm

To the Stockholders and Board of
Directors of Pennsylvania Electric Company:

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

Consolidated financial statements

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

As discussed in Note 2(G) to the consolidated financial statements, the Company changed its method of accounting for asset retirement obligations as of January 1, 2003. As discussed in Note 6 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 Report on Internal Control Over Financial Reporting, that the Company maintained effective internal control over financial reporting as of December 31, 2004 based on criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), is fairly stated, in all material respects, based on those criteria. Furthermore, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2004, based on criteria established in *Internal Control – Integrated Framework* issued by the COSO. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express opinions on management's assessment and on the effectiveness of the Company's internal control over financial reporting based on our audit. We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we consider necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

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

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

PricewaterhouseCoopers LLP
Cleveland, Ohio
March 7, 2005

PENNSYLVANIA ELECTRIC COMPANY

SELECTED FINANCIAL DATA

	2004	2003	2002	Nov. 7 - Dec. 31, 2001	Jan. 1 - Nov. 6, 2001	2000
Operating Revenues	$ 1,036,070	$ 974,857	$ 1,027,102	$ 140,062	$ 834,548	$ 901,881
Operating Income	$ 73,680	$ 60,245	$ 88,190	$ 14,341	$ 70,049	$ 80,336
Income Before Cumulative Effect of Accounting Change	$ 36,030	$ 20,237	$ 50,910	$ 10,795	$ 23,718	$ 39,250
Net Income	$ 36,030	$ 21,333	$ 50,910	$ 10,795	$ 23,718	$ 39,250
Total Assets	$ 2,813,752	$ 3,052,243	$ 3,163,254	$ 3,300,269		$ 2,331,484
Capitalization as of December 31:						
Common Stockholder's Equity	$ 1,305,015	$ 1,297,332	$ 1,353,704	$ 1,306,576		$ 469,837
Company-Obligated Trust Preferred Securities	–	–	92,214	92,000		100,000
Long-Term Debt and Other Long-Term Obligations	481,871	438,764	470,274	472,400		519,481
Total Capitalization	$ 1,786,886	$ 1,736,096	$ 1,916,192	$ 1,870,976		$ 1,089,318
Capitalization Ratios:						
Common Stockholder's Equity	73.0%	74.7%	70.7 %	69.8%		43.1 %
Company-Obligated Trust Preferred Securities	–	–	4.8	4.9		9.2
Long-Term Debt and Other Long-Term Obligations	27.0	25.3	24.5	25.3		47.7
Total Capitalization	100.0%	100.0%	100.0 %	100.0%		100.0 %
Distribution Kilowatt-Hour Deliveries (Millions):						
Residential	4,249	4,166	4,196	721	3,264	3,949
Commercial	4,792	4,748	4,753	758	3,733	4,509
Industrial	4,589	4,443	4,336	685	3,658	4,698
Other	39	41	42	7	34	40
Total	13,669	13,398	13,327	2,171	10,689	13,196
Customers Served:						
Residential	505,999	503,738	503,007	502,901		502,052
Commercial	78,519	77,737	77,125	76,005		74,282
Industrial	2,492	2,545	2,605	2,652		2,703
Other	1,056	1,069	1,081	1,099		1,110
Total	588,066	585,089	583,818	582,657		580,147

PENNSYLVANIA ELECTRIC COMPANY

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

This discussion includes forward-looking statements based on information currently available to management. Such statements are subject to certain risks and uncertainties. These statements typically contain, but are not limited to, the terms "anticipate," "potential," "expect," "believe," "estimate" and similar words. Actual results may differ materially due to the speed and nature of increased competition and deregulation in the electric utility industry, economic or weather conditions affecting future sales and margins, changes in markets for energy services, changing energy and commodity market prices, replacement power costs being higher than anticipated or inadequately hedged, maintenance costs being higher than anticipated, legislative and regulatory changes (including revised environmental requirements), adverse regulatory or legal decisions and outcomes (including revocation of necessary licenses or operating permits, fines or other enforcement actions and remedies) of governmental investigations, including by the Securities and Exchange Commission as disclosed in our Securities and Exchange Commission filings, the availability and cost of capital, our ability to experience growth in the distribution business, our ability to access the public securities and other capital markets, further investigation into the causes of the August 14, 2003, regional power outage and the outcome, cost and other effects of present and potential legal and administrative proceedings and claims related to the outage, the risks and other factors discussed from time to time in our Securities and Exchange Commission filings, and other similar factors. We expressly disclaim any current intention to update any forward-looking statements contained herein as a result of new information, future events, or otherwise.

Reclassifications

As discussed in Note 1 to the consolidated financial statements, certain prior year amounts have been reclassified to conform to the current year presentation. Revenue amounts related to transmission activities previously recorded as wholesale electric sales revenues were reclassified as transmission revenues. Expenses (including transmission and congestion charges) were reclassified among purchased power, other operating costs and amortization of regulatory assets to conform to the current year presentation. These reclassifications did not change previously reported net income in 2003 and 2002.

Results of Operations

Net income increased to $36 million in 2004, compared to $21 million in 2003. The increase in 2004 resulted from higher operating revenues and other income partially offset by higher purchased power costs and other operating costs. Net income decreased to $21 million or 58.1% in 2003 from $51 million in 2002. In 2003, net income was lower due to lower operating revenues partially offset by reduced purchased power costs, other operating costs and depreciation and amortization charges.

Operating revenues increased by $61 million in 2004 compared to 2003, primarily due to higher revenues from distribution deliveries and transmission revenues, which were partially offset by lower retail generation revenues. Revenues from distribution deliveries increased by $30 million due to higher unit prices and a 2.0% increase in electricity throughput with increases in all customer sectors. Kilowatt-hour deliveries increased to commercial and industrial customers reflecting an improving economy in our service area. Retail generation revenues decreased by $9 million due to lower composite prices. This decrease was partially offset by a 3.1% increase in retail generation kilowatt-hour sales due to generation customers returning to us after switching to alternative suppliers. The lower retail generation prices were due to the PPUC Restructuring Settlement order (see Note 7). There was minimal wholesale sales activity in 2004 and 2003. Transmission revenues increased $40 million in 2004 compared with 2003 due to an amended power supply agreement with FES, which resulted in our recognizing certain transmission revenues that were previously attributed to FES which also increased transmission expenses as discussed below.

The significant decrease in customer shopping in 2004 reflects our low generation price as provider of last resort. Alternative suppliers have not been able to match that price by a sufficient margin to ensure profitability, particularly in the industrial sector.

Operating revenues decreased by $52 million in 2003 compared to 2002, primarily due to lower retail generation revenues and wholesale sales revenues slightly offset by higher distribution deliveries revenues. Total retail generation kilowatt-hour sales decreased 2.5% ($22 million in operating revenues) as a result of decreases in industrial sales (7.2%), residential sales (0.7%) and commercial sales (0.6%). The decrease in industrial sales was primarily due to more industrial customers being served by alternative suppliers. Wholesale sales revenues decreased by $32 million in 2003, primarily attributable to lower sales to non-affiliated companies. Kilowatt-hour deliveries increased by 0.5% due to an increase in industrial deliveries as a result of a slightly improving economy – partially offset by lower deliveries to residential and commercial customers.

Changes in electric generation sales and distribution deliveries in 2004 and 2003 are summarized in the following table:

Changes in Kilowatt-hour Sales *Increase (Decrease)*	**2004**	**2003**
Electric Generation:		
Retail	3.1 %	(2.5)%
Wholesale	(100.0)%	(99.5)%
Total Electric Retail Generation Sales	3.1 %	(6.4)%
Distribution Deliveries:		
Residential	2.0 %	(0.7)%
Commercial	0.9 %	(0.1)%
Industrial	3.3 %	2.5 %
Total Distribution Deliveries	2.0 %	0.5%

Operating Expenses and Taxes

Total operating expenses and taxes increased by $48 million or 5.2% in 2004 and decreased $24 million or 2.6% in 2003, compared to the preceding year. Higher purchased power costs, other operating costs and income taxes, accounted for the increase in 2004. In 2003, the decrease was due to lower purchased power costs, depreciation, amortization and income taxes, offset in part by an increase in general taxes. The following table presents changes from the prior year by expense category.

Operating Expenses and Taxes - Changes **Increase (Decrease)**	**2004**	**2003**
	(In millions)	
Purchase power costs	$ 20	$ (6)
Other operating costs	19	(2)
Provision for depreciation	(6)	(6)
Amortization of regulatory assets	7	(5)
General taxes	1	2
Income taxes	7	(7)
Total operating expenses and taxes	$ 48	$ (24)

Purchased power costs increased by $20 million or 3.7% in 2004, compared to the prior year. The increase was due primarily to higher kilowatt-hours purchased to meet the increased retail generation sales requirements. Purchased power costs decreased by $6.0 million or 1.1% in 2003, compared to 2002, due primarily to a reduction in kilowatt-hours purchased to support lower kilowatt-hour sales to retail and wholesale customers.

Other operating costs increased by $19 million or 10.5% in 2004, compared to 2003. The increase was primarily due to increased transmission expenses, which were assumed in 2004 due to a change in the power supply agreement with FES and to higher vegetation management costs. Other operating costs were relatively unchanged in 2003 compared to 2002.

Depreciation charges decreased in 2004 primarily due to certain assets being fully depreciated in 2003. Depreciation charges decreased in 2003 compared to 2002 due to information system assets being fully depreciated in 2002 and higher cost of removal charges in 2002 compared to 2003. Amortization of regulatory assets increased in 2004 compared to the prior year due to a higher level of deferred NUG cost recovery. The decrease in 2003 from 2002 was due to lower CTC revenue recovering deferred costs.

Net Interest Charges

Net interest charges decreased $2 million in 2004 compared to the prior year, reflecting the redemption of $100 million of 7.34% subordinated debentures in September 2004. This decrease was partially offset by interest expense resulting from intercompany loans through the money pool discussed below. We became a net borrower in 2004 due to a required repayment to the NUG trust fund. In 2003, we were a net lender due to a $106 million withdrawal from the NUG trust. Net interest charges increased $3 million in 2003, compared to the prior year. The increase was due to the change in deferred interest costs, offset in part by lower preferred stock dividend requirements.

Cumulative Effect of Accounting Change

Upon adoption of SFAS 143 in the first quarter of 2003, we recorded an after-tax gain to net income of $1.1 million. The cumulative effect adjustment for unrecognized depreciation and accretion, offset by the reduction in the existing decommissioning liabilities and ceasing the accounting practice of depreciating non-regulated generation assets using a cost of removal component, was a $1.9 million increase to income, or $1.1 million net of income taxes.

Capital Resources and Liquidity

Our cash requirements in 2004 for operating expenses, construction expenditures and scheduled debt maturities were met with a combination of cash from operations and funds from the capital markets. During 2005 and thereafter, we expect to meet our contractual obligations with a combination of cash from operations and funds from the capital markets.

Changes in Cash Position

There was no change as of December 31, 2004 and December 31, 2003 in our cash and cash equivalents of $36,000.

Cash Flows From Operating Activities

Our net cash provided from operating activities was $46 million in 2004, $16 million in 2003 and $39 million in 2002, summarized as follows:

Operating Cash Flows	2004	2003	2002
		(In millions)	
Cash earnings[1]	$ 112	$ 88	$ 63
Pension trust contribution[2]	(30)	–	–
Working capital and other	(36)	(72)	(24)
Total	$ 46	$ 16	$ 39

[1] Cash earnings is a non-GAAP measure (see reconciliation below).
[2] Pension trust contribution net of $20 million of income tax benefits.

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.

Reconciliation of Cash Earnings	2004	2003	2002
		(In millions)	
Net Income (GAAP)	$ 36	$ 21	$ 51
Non-Cash Charges (Credits):			
Provision for depreciation	47	52	59
Amortization of regulatory assets	50	45	49
Deferred costs recoverable as regulatory assets	(87)	(80)	(106)
Deferred income taxes and investment tax credits	58	41	11
Cumulative effect of accounting change	–	(2)	–
Other non-cash expenses	8	11	(1)
Cash earnings (Non-GAAP)	$ 112	$ 88	$ 63

Net cash provided from operating activities increased $30 million in 2004 compared to 2003 resulting from increases of $36 million from working capital changes and $24 million in cash earnings, partially offset by a $30 million after-tax voluntary pension contribution. The increase from working capital was principally due to changes in accounts payable balances. The increase in cash earnings is described under "Results of Operations". Net cash from operating activities decreased by $23 million in 2003 compared to 2002 due to a $48 million decrease from changes in working capital partially offset by a $25 million increase in cash earnings which is described under "Results of Operations". The decrease from working capital resulted from a $79 million change in accounts payable partially offset by a $41 million change in receivables.

Cash Flows From Financing Activities

Net cash provided from financing activities of $76 million in 2004 compares to net cash of $49 million used in 2003. The net change reflects a $97 million increase in borrowings and a $28 million decrease in common stock dividend payments to FirstEnergy. The net decrease of $17 million in net cash used for financing activities in 2003 compared to 2002 reflects a $24 million reduction in net debt refinancing activity partially offset by a $7 million increase in common stock dividend payments to FirstEnergy. The following table provides details regarding new issues and redemptions during each year:

Securities Issued or Redeemed	**2004**	**2003**	**2002**
		(In millions)	
New Issues - Unsecured notes	$150	$ –	$ –
Redemptions - Unsecured notes	229	1	50
Short-term Borrowings, net (use)/source of cash	163	(12)	13

In March 2004, we completed a receivables financing arrangement providing for borrowings of up to $75 million. The borrowing rate is based on bank commercial paper rates. We are required to pay an annual facility fee of 0.30% on the entire finance limit. The facility was undrawn as of December 31, 2004 and matures on March 29, 2005. These receivables financing arrangements are expected to be renewed prior to expiration.

On September 1, 2004, we redeemed at par $100 million principal amount of our subordinated debentures in connection with the concurrent redemption at par of $100 million principal amount of 7.34% Penelec Capital Trust Preferred Securities.

As of December 31, 2004, we had approximately $241 million of short-term indebtedness, compared to $78 million at the end of 2003. Penelec has obtained authorization from the SEC to incur short-term debt of up to $250 million (including the utility money pool). We will not issue FMB other than as collateral for senior notes, since our senior note indentures prohibit (subject to certain exceptions) us from issuing any debt which is senior to the senior notes. As of December 31, 2004, we had the ability to issue $25 million of additional senior notes based upon FMB collateral. We have no restrictions on the issuance of preferred stock.

We have the ability to borrow from our regulated affiliates and FirstEnergy to meet our short-term working capital requirements. FESC administers this money pool and tracks surplus funds of FirstEnergy and its regulated subsidiaries. Companies receiving a loan under the money pool agreements must repay the principal, 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 the pool and is based on the average cost of funds available through the pool. The average interest rate for borrowings under these arrangements in 2004 was 1.43%.

Our access to capital markets and costs of financing are dependent on the ratings of our securities and that of FirstEnergy. The ratings outlook on all securities is stable.

Ratings of Securities	**Securities**	**S&P**	**Moody's**	**Fitch**
FirstEnergy	Senior unsecured	BB+	Baa3	BBB-
Penelec	Senior secured	BBB	Baa1	BBB+
	Senior unsecured	BBB-	Baa2	BBB

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

Cash Flows From Investing Activities

Cash used for investing activities totaled $123 million in 2004 and cash provided from investing activities totaled approximately $22 million in 2003. In both periods, cash outflows for property additions were made to support the distribution of electricity. In 2004, cash was used for a $51 million repayment to the NUG trust fund, while in 2003 cash was provided from a $106 million withdrawal from the NUG trust fund. Finally, net loan payments to associated companies resulted in cash used of $8 million in 2004, whereas we received net payments of $2 million in 2003.

Our capital spending for the period 2005-2007 is expected to be about $272 million for property additions and improvements, of which approximately $89 million applies to 2005.

Contractual Obligations

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

Contractual Obligations	Total	2005	2006-2007	2008-2009	Thereafter
			(In millions)		
Long-term debt [2]	$ 491	$ 8	$ 3	$ 100	$ 380
Short-term borrowings	241	241	–	–	–
Purchases [1]	3,437	345	887	793	1,412
Total	$ 4,169	$ 594	$ 890	$ 893	$ 1,792

[1] Power purchases under contracts with fixed or minimum quantities and approximate timing
[2] Amounts reflected do not include interest on long-term debt.

Market Risk Information

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

Commodity Price Risk

We are exposed to market risk primarily due to fluctuations in electricity and natural gas prices. To manage the volatility relating to these exposures, we use a variety of non-derivative and derivative instruments, including options and futures contracts. The derivatives are used for hedging purposes. As of December 31, 2004 and 2003, we had commodity derivative contracts related to energy production that did not qualify for hedge treatment under SFAS 133. The fair value of these contracts was $15 million as of December 31, 2004 and 2003, and are included in non-current assets.

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 utilize these results in developing estimates of fair value for financial reporting purposes and for internal management decision making. Sources of information for the valuation of derivative contracts by year are summarized in the following table:

Source of Information – Fair Value by Contract Year

	2005	2006	2007	2008	Thereafter	Total
			(In millions)			
Prices based on external sources[1]	$ 4	$ 3	$ –	$ –	$ –	$ 7
Prices based on models	–	–	2	2	4	8
Total[2]	$ 4	$ 3	$ 2	$ 2	$ 4	$ 15

[1] Broker quote sheets.
[2] *Includes $15 million from an embedded option that is offset by a regulatory liability and does not affect earnings.*

We perform sensitivity analyses to estimate our exposure to the market risk of our commodity position. A hypothetical 10% adverse shift in quoted market prices in the near term on derivative instruments would not have had a material effect on our consolidated financial position or cash flows as of December 31, 2004.

Interest Rate Risk

Our exposure to fluctuations in market interest rates is reduced since our debt has fixed interest rates.

Comparison of Carrying Value to Fair Value

Year of Maturity (Dollars in millions)	2005	2006	2007	2008	2009	There-after	Total	Fair Value
Assets								
Investments Other Than Cash and Cash Equivalents-Fixed Income						$ 146	$ 146	$ 146
Average interest rate						4.3%	4.3%	
Liabilities								
Long-term Debt and Other Long-term Obligations:								
Fixed rate	$ 8		$ 3		$ 100	$ 380	$ 491	$ 521
Average interest rate	7.5%		6.1%		6.1%	6.0%	6.0%	
Short-term Borrowings	241						$ 241	$ 241
Average interest rate	2.0%						2.0%	

Equity Price Risk

Included in nuclear decommissioning trusts are marketable equity securities carried at their current fair value of approximately $60 million and $54 million at December 31, 2004 and 2003, respectively. A hypothetical 10% decrease in prices quoted by stock exchanges would result in a $6 million reduction in fair value as of December 31, 2004 (see Note 4 – Fair Value of Financial Instruments).

Outlook

Beginning in 1999, all of our customers were able to select alternative energy suppliers. We continue to deliver power to homes and businesses through our existing distribution system, which remains regulated. The PPUC authorized our rate restructuring plan, establishing separate charges for transmission, distribution, generation and stranded cost recovery, which is recovered through a CTC. Customers electing to obtain power from an alternative supplier have their bills reduced based on the regulated generation component, and the customers receive a generation charge from the alternative supplier. We have a continuing responsibility, referred to as our PLR obligation, to provide power to those customers not choosing to receive power from an alternative energy supplier, subject to certain limits.

We recognize, as regulatory assets, costs which the PPUC and the FERC 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 when incurred. All regulatory assets are expected to be recovered under our regulatory plan. Our regulatory assets totaled $200 million and $497 million as of December 31, 2004 and December 31, 2003, respectively.

Regulatory Matters

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

On January 12, 2005, we filed, before the PPUC, a request for deferral of transmission-related costs beginning January 1, 2005, estimated to be approximately $4 million per month. Various parties have intervened in this case.

See Note 7 to the consolidated financial statements for a more complete and detailed discussion of regulatory matters in Pennsylvania.

Environmental Matters

We have been named as a PRP 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 be held liable on a joint and several basis. We accrue environmental liabilities only when we can conclude that it is probable that we have an obligation for such costs and can reasonably determine 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.

Legal Matters

Various lawsuits, claims (including claims for asbestos exposure) and proceedings related to our normal business operations are pending against us, the most significant of which are described above and in Note 11(C) to the consolidated financial statements.

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.

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 should 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 were indicated, we would recognize a loss – calculated as the difference between the implied fair value of its goodwill and the carrying value of the goodwill. Our annual review was completed in the third quarter of 2004, with no impairment of goodwill indicated. The forecasts used in our evaluation 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. In the year ended December 31, 2004, we adjusted goodwill related to interest received on a pre-merger income tax refund and for the reversal of tax valuation allowances related to income tax benefits realized attributable to prior period capital loss carryforwards that were used to offset capital gains generated in 2004. As of December 31, 2004, we had recorded goodwill of approximately $888 million.

Regulatory Accounting

We are subject to regulation that sets the prices (rates) we are permitted to charge our customers based on the 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 rate-making process results in the recording of regulatory assets based on anticipated future cash inflows. We regularly review these assets to assess their ultimate recoverability within the approved regulatory guidelines. Impairment risk associated with these assets relates to potentially adverse legislative, judicial or regulatory actions in the future.

Revenue Recognition

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

Pension and Other Postretirement Benefits Accounting

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

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

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

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

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

In the third quarter of 2004, FirstEnergy made a $500 million voluntary contribution to its pension plan (our share was $50 million). Prior to this contribution, projections indicated that cash contributions of approximately $600 million would have been required during the 2006 to 2007 time period under minimum funding requirements established by the IRS. FirstEnergy's election to pre-fund the plan is expected to eliminate that funding requirement.

As a result of our voluntary contribution and the increased market value of pension plan assets, we reduced our accrued benefit cost as of December 31, 2004 by $32 million. As prescribed by SFAS 87, we increased our additional minimum liability by $18 million, offset by a charge to OCI. The balance in AOCL of $52 million (net of $37 million in deferred taxes) will reverse in future periods to the extent the fair value of trust assets exceeds the accumulated benefit obligation.

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

Long-Lived Assets

In accordance with SFAS No. 144, we periodically evaluate our long-lived assets to determine whether conditions exist that would indicate that the carrying value of an asset might not be fully recoverable. The accounting standard requires that if the sum of future cash flows (undiscounted) expected to result from an asset is less than the carrying value of the asset, an asset impairment must be recognized in the financial statements. If impairment has occurred, we recognize a loss – calculated as the difference between the carrying value and the estimated fair value of the asset (discounted future net cash flows).

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

Nuclear Decommissioning

In accordance with SFAS 143, we recognize an ARO for the future decommissioning of TMI-2. The ARO liability represents an estimate of the fair value of our current obligation related to nuclear decommissioning and the retirement of other assets. A fair value measurement inherently involves uncertainty in the amount and timing of settlement of the liability. We used an expected cash flow approach to measure the fair value of the nuclear decommissioning ARO. This approach applies probability weighting to discounted future cash flow scenarios that reflect a range of possible outcomes.

New Accounting Standards and Interpretations Adopted

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

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

PENNSYLVANIA ELECTRIC COMPANY

CONSOLIDATED STATEMENTS OF INCOME

	2004	2003	2002
		(In thousands)	
OPERATING REVENUES (Note 2(I))	$ 1,036,070	$ 974,857	$ 1,027,102
OPERATING EXPENSES AND TAXES:			
Fuel and purchased power (Note 2(I))	570,369	550,155	556,133
Other operating costs (Note 2(I))	197,069	178,393	180,161
Provision for depreciation	47,104	51,754	58,913
Amortization of regulatory assets	50,403	44,908	48,990
General taxes	68,132	66,999	65,301
Income taxes	29,313	22,403	29,414
Total operating expenses and taxes	962,390	914,612	938,912
OPERATING INCOME	73,680	60,245	88,190
OTHER INCOME	2,314	1,885	1,742
NET INTEREST CHARGES:			
Interest on long-term debt	30,029	29,565	31,758
Allowance for borrowed funds used during construction	(248)	(320)	(52)
Deferred interest	190	4,553	(3,299)
Other interest expense	9,993	4,318	3,061
Subsidiary's preferred stock dividend requirements	–	3,777	7,554
Net interest charges	39,964	41,893	39,022
INCOME BEFORE CUMULATIVE EFFECT OF ACCOUNTING CHANGE	36,030	20,237	50,910
Cumulative effect of accounting change (net of income taxes of $777,000) (Note 2(G))	–	1,096	–
NET INCOME	$ 36,030	$ 21,333	$ 50,910

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

PENNSYLVANIA ELECTRIC COMPANY

CONSOLIDATED BALANCE SHEETS

As of December 31,	2004	2003
	(In thousands)	
ASSETS		
UTILITY PLANT:		
In service	$ 1,981,846	$ 1,966,624
Less-Accumulated provision for depreciation	776,904	785,715
	1,204,942	1,180,909
Construction work in progress	22,816	29,063
	1,227,758	1,209,972
OTHER PROPERTY AND INVESTMENTS:		
Nuclear plant decommissioning trusts	109,620	102,673
Non-utility generation trusts	95,991	43,864
Long-term notes receivable from associated companies	14,001	13,794
Other	18,746	19,635
	238,358	179,966
CURRENT ASSETS:		
Cash and cash equivalents	36	36
Receivables-		
Customers (less accumulated provisions of $4,712,000 and $5,833,000, respectively, for uncollectible accounts)	121,112	124,462
Associated companies	97,528	88,598
Other (less accumulated provisions of $4,000 and $399,000, respectively, for uncollectible accounts)	12,778	15,767
Notes receivable from associated companies	7,352	-
Prepayments and other	7,198	2,511
	246,004	231,374
DEFERRED CHARGES:		
Goodwill	888,011	898,547
Regulatory assets	200,173	497,219
Accumulated deferred income tax benefits	-	16,642
Other	13,448	18,523
	1,101,632	1,430,931
	$ 2,813,752	$ 3,052,243
CAPITALIZATION AND LIABILITIES		
CAPITALIZATION (See Consolidated Statements of Capitalization):		
Common stockholder's equity	$ 1,305,015	$ 1,297,332
Long-term debt and other long-term obligations	481,871	438,764
	1,786,886	1,736,096
CURRENT LIABILITIES:		
Currently payable long-term debt	8,248	125,762
Short-term borrowings (Note 10)-		
Associated companies	241,496	78,510
Accounts payable-		
Associated companies	56,154	55,831
Other	25,960	40,192
Accrued taxes	7,999	8,705
Accrued interest	9,695	12,694
Other	23,750	21,764
	373,302	343,458
NONCURRENT LIABILITIES:		
Power purchase contract loss liability	382,548	670,482
Asset retirement obligation	66,443	105,089
Accumulated deferred income taxes	37,318	-
Retirement benefits	118,247	145,081
Other	49,008	52,037
	653,564	972,689
COMMITMENTS AND CONTINGENCIES (Notes 5 and 11)		
	$ 2,813,752	$ 3,052,243

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

PENNSYLVANIA ELECTRIC COMPANY

CONSOLIDATED STATEMENTS OF CAPITALIZATION

As of December 31,	2004	2003
(Dollars in thousands, except per share amounts)		
COMMON STOCKHOLDER'S EQUITY:		
Common stock, par value $20 per share, authorized 5,400,000 shares 5,290,596 shares outstanding	$ 105,812	$ 105,812
Other paid-in capital	1,205,948	1,215,667
Accumulated other comprehensive loss (Note 2 (F))	(52,813)	(42,185)
Retained earnings (Note 8(A))	46,068	18,038
Total common stockholder's equity	1,305,015	1,297,332
LONG-TERM DEBT AND OTHER LONG-TERM OBLIGATIONS (Note 8 (C)):		
First mortgage bonds:		
6.125% due 2007	3,495	3,700
5.350% due 2010	12,310	12,310
5.350% due 2010	12,000	12,000
5.800% due 2020	20,000	20,000
6.050% due 2025	25,000	25,000
Total first mortgage bonds	72,805	73,010
Unsecured notes:		
5.750% due 2004	–	125,000
7.500% due 2005	8,000	8,000
6.125% due 2009	100,000	100,000
7.770% due 2010	35,000	35,000
5.125% due 2014	150,000	–
6.625% due 2019	125,000	125,000
7.340% due 2039	–	95,520
7.690% due 2039	–	2,968
Total unsecured notes	418,000	491,488
Capital lease obligations (Note 5)	43	540
Net unamortized discount on debt	(729)	(512)
Long-term debt due within one year	(8,248)	(125,762)
Total long-term debt and other long-term obligations	481,871	438,764
TOTAL CAPITALIZATION	$ 1,786,886	$ 1,736,096

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

PENNSYLVANIA ELECTRIC COMPANY

CONSOLIDATED STATEMENTS OF CASH FLOWS

	2004	2003	2002
		(In thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net Income	$ 36,030	$ 21,333	$ 50,910
Adjustments to reconcile net income to net cash from operating activities:			
Provision for depreciation	47,104	51,754	58,913
Amortization of regulatory assets	50,403	44,908	48,990
Deferred costs recoverable as regulatory assets	(87,379)	(80,126)	(105,380)
Deferred income taxes and investment tax credits, net	77,375	40,889	10,861
Accrued retirement benefit obligations	5,822	2,727	–
Accrued compensation, net	3,226	7,956	(1,275)
Cumulative effect of accounting change (Note 2(G))	–	(1,873)	–
Pension trust contribution	(50,281)	–	–
Decrease (Increase) in operating assets:			
Receivables	(2,591)	13,052	(27,509)
Prepayments and other current assets	(4,687)	41	6,054
Increase (Decrease) in operating liabilities:			
Accounts payable	(13,909)	(84,700)	(5,514)
Accrued taxes	(705)	(4,215)	(7,984)
Accrued interest	(2,999)	–	411
Other	(11,116)	4,230	10,835
Net cash provided from operating activities	46,293	15,976	39,312
CASH FLOWS FROM FINANCING ACTIVITIES:			
New Financing-			
Long-term debt	150,000	–	–
Short-term borrowings, net	162,986	–	12,804
Redemptions and Repayments-			
Long-term debt	(228,670)	(812)	(49,973)
Short-term borrowings, net	–	(11,917)	–
Dividend Payments-			
Common stock	(8,000)	(36,000)	(29,000)
Net cash provided from (used for) financing activities	76,316	(48,729)	(66,169)
CASH FLOWS FROM INVESTING ACTIVITIES:			
Property additions	(51,801)	(44,657)	(50,671)
Non-utility generation trusts withdrawals (contributions)	(50,614)	66,327	49,044
Loan repayments from (payments to) associated companies, net	(7,559)	1,721	–
Other, net	(12,635)	(912)	(239)
Net cash provided from (used for) investing activities	(122,609)	22,479	(1,866)
Net change in cash and cash equivalents	–	(10,274)	(28,723)
Cash and cash equivalents at beginning of period	36	10,310	39,033
Cash and cash equivalents at end of period	$ 36	$ 36	$ 10,310
SUPPLEMENTAL CASH FLOWS INFORMATION:			
Cash Paid During the Year-			
Interest (net of amounts capitalized)	$ 40,765	$ 37,497	$ 32,695
Income taxes (refund)	$ (36,434)	$ 10,695	$ 43,613

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

PENNSYLVANIA ELECTRIC COMPANY

CONSOLIDATED STATEMENTS OF TAXES

	2004	2003	2002
		(In thousands)	
GENERAL TAXES:			
State gross receipts*	$ 55,390	$ 53,716	$ 55,505
Other	12,742	13,283	9,796
Total general taxes	$ 68,132	$ 66,999	$ 65,301
PROVISION FOR INCOME TAXES:			
Currently payable-			
Federal	$ (38,759)	$ (15,968)	$ 17,554
State	(8,615)	692	5,833
	(47,374)	(15,276)	23,387
Deferred, net-			
Federal	64,435	35,136	10,600
State	13,959	6,741	1,293
	78,394	41,877	11,893
Investment tax credit amortization	(1,019)	(988)	(1,032)
Total provision for income taxes	$ 30,001	$ 25,613	$ 34,248
INCOME STATEMENT CLASSIFICATION OF PROVISION FOR INCOME TAXES:			
Operating income	$ 29,313	$ 22,403	$ 29,414
Other income	688	2,433	4,834
Cumulative effect of accounting change	–	777	–
Total provision for income taxes	$ 30,001	$ 25,613	$ 34,248
RECONCILIATION OF FEDERAL INCOME TAX EXPENSE AT STATUTORY RATE TO TOTAL PROVISION FOR INCOME TAXES:			
Book income before provision for income taxes	$ 66,031	$ 46,946	$ 85,158
Federal income tax expense at statutory rate	$ 23,111	$ 16,431	$ 29,805
Increases (reductions) in taxes resulting from-			
Amortization of investment tax credits	(1,019)	(988)	(1,032)
Depreciation	1,649	2,655	1,591
State income tax, net of federal benefit	3,474	4,831	4,702
Other, net	2,786	2,684	(818)
Total provision for income taxes	$ 30,001	$ 25,613	$ 34,248
ACCUMULATED DEFERRED INCOME TAXES AT DECEMBER 31:			
Property basis differences	$ 294,220	$ 291,752	$ 242,192
Nuclear decommissioning	(40,349)	(39,869)	(41,665)
Non-utility generation costs	(181,649)	(223,350)	(223,644)
Purchase accounting basis difference	(762)	(762)	(762)
Sale of generation assets	7,495	7,495	7,495
Customer receivables for future income taxes	52,063	55,817	52,793
Other comprehensive income	(37,455)	(29,908)	–
Employee benefits	(20,397)	(42,368)	–
Other	(35,848)	(35,449)	(37,926)
Net deferred income tax liability (asset)	$ 37,318	$ (16,642)	$ (1,517)

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

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. ORGANIZATION AND BASIS OF PRESENTATION:

The consolidated financial statements include Penelec (Company) and its wholly owned subsidiaries. The Company is a wholly owned subsidiary of FirstEnergy. FirstEnergy also holds directly all of the issued and outstanding common shares of its other principal electric utility subsidiaries, including OE, CEI, TE, ATSI, JCP&L and Met-Ed.

The Company follows GAAP and complies with the regulations, orders, policies and practices prescribed by the SEC, PPUC and the FERC. The preparation of financial statements in conformity with GAAP requires management to make periodic estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses and the disclosure of contingent assets and liabilities. Actual results could differ from these estimates. Revenue amounts related to transmission activities previously recorded as wholesale electric sales revenues were reclassified as transmission revenues. Expenses (including transmission and congestion charges) were reclassified among purchased power, other operating costs and amortization of regulatory assets to conform with the current year presentation of generation commodity costs.

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

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

The Company accounts for the effects of regulation through the application of SFAS 71 to its operating utilities when its 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.

Regulatory Assets-

The Company recognizes, as regulatory assets, costs which the FERC and the PPUC 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 Company's regulatory plan. The Company continues to bill and collect cost-based rates for its transmission and distribution services, which remain regulated; accordingly, it is appropriate that the Company continue the application of SFAS 71 to those operations.

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

	2004	2003
	(In millions)	
Regulatory transition costs	$ 114	$ 366
Customer receivables for future income taxes	119	128
Nuclear decommissioning costs	(47)	(1)
Loss on reacquired debt and other	14	4
Total	$ 200	$ 497

Regulatory transition charges as of December 31, 2004 consist primarily of deferred charges for above-market costs from power supplied by NUGs. These costs are being recovered through CTC revenues. The regulatory asset for above-market NUG costs and a corresponding liability are adjusted to fair value at the end of each quarter.

Accounting for Generation Operations-

The application of SFAS 71 was discontinued in 1999 with respect to the Company's generation operations. The Company subsequently divested substantially all of its generating assets. The SEC's interpretive guidance and EITF 97-4 regarding asset impairment measurement, provides that any supplemental regulated cash flows such as a CTC should be excluded from the cash flows of assets in a portion of the business not subject to regulatory accounting practices. If those assets are impaired, a regulatory asset should be established if the costs are recoverable through regulatory cash flows.

(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 Company's principal business is providing electric service to customers in Pennsylvania. The Company's 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 Company accrues the estimated unbilled amount receivable as revenue and reverses the related prior period estimate.

Receivables from customers include sales to residential, commercial and industrial customers and sales to wholesale customers. There was no material concentration of receivables as of December 31, 2004 or 2003, with respect to any particular segment of the Company's customers. Total customer receivables were $121 million (billed – $76 million and unbilled – $45 million) and $124 million (billed – $73 million and unbilled – $51 million) as of December 31, 2004 and 2003, respectively.

(D) PROPERTY, PLANT AND EQUIPMENT-

As a result of the Company's acquisition by FirstEnergy in 2001, a portion of the Company's property, plant and equipment was adjusted to reflect fair value. The majority of the Company's property, plant and equipment continues to be reflected at original cost since such assets remain subject to rate regulation on a historical cost basis. The costs of normal maintenance, repairs and minor replacements are expensed as incurred. The Company's accounting policy for planned major maintenance projects is to recognize liabilities as they are incurred.

The Company provides for depreciation on a straight-line basis at various rates over the estimated lives of property included in plant in service. The annualized composite rate was approximately 2.5% in 2004, 2.7% in 2003, and 3.0% in 2002. The decrease in the composite depreciation rate reflects changes in the depreciable plant base due to assets with higher depreciation rates being fully depreciated since 2002.

(E) ASSET IMPAIRMENTS-

Long-Lived Assets

The Company 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, the Company evaluates its goodwill for impairment at least annually and would make such an evaluation more frequently if indicators of impairment should 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, the Company 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. The Company's 2004 annual review was completed in the third quarter of 2004 with no impairment indicated. The forecasts used in the Company's evaluations of goodwill reflect operations consistent with its general business assumptions. Unanticipated changes in those assumptions could have a significant effect on the Company's future evaluations of goodwill. As of December 31, 2004, the Company had $888 million of goodwill. In 2004, the Company adjusted goodwill for interest received on a pre-merger income tax refund and for the reversal of tax valuation allowances related to income tax benefits realized attributable to prior period capital loss carryforwards that were offset by capital gains generated in 2004.

Investments

The Company periodically evaluates for impairment investments that include 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. The Company considers, among other factors, the length of time and the extent to which the security's fair value has been less than cost and the near-term financial prospects of the security issuer when evaluating investments for impairment. The fair value and unrealized gains and losses of the Company's investments are disclosed in Note 4.

(F) COMPREHENSIVE INCOME-

Comprehensive income includes net income as reported on the Consolidated Statements of Income and all other changes in common stockholder's equity except those resulting from transactions with FirstEnergy. As of December 31, 2004, accumulated other comprehensive loss consisted of a minimum liability for unfunded retirement benefits of $52 million and unrealized losses on derivative instrument hedges of $1 million. As of December 31, 2003, accumulated other comprehensive loss consisted of a minimum liability for unfunded retirement benefits of $42 million.

(G) CUMULATIVE EFFECT OF ACCOUNTING CHANGE

As a result of adopting SFAS 143 in January 2003, asset retirement costs were recorded in the amount of $93 million as part of the carrying amount of the related long-lived asset, offset by accumulated depreciation of $93 million. The ARO liability on the date of adoption was $99 million, including accumulated accretion for the period from the date the liability was incurred to the date of adoption. 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 $1.9 million increase to income ($1.1 million net of tax) in the year ended December 31, 2003. If SFAS 143 had been applied during 2002, the impact would not have been material to the Company's Consolidated Statements of Income.

(H) INCOME TAXES-

Details of the total provision for income taxes are shown on the Consolidated Statements of Taxes. The Company records income taxes in accordance with the liability method of accounting. Deferred income taxes reflect the net tax effect of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used 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. The Company is included in FirstEnergy's consolidated federal income tax return. The consolidated tax liability is allocated on a "stand-alone" company basis, with the Company recognizing the tax benefit for any tax losses or credits it contributes to the consolidated return.

(I) TRANSACTIONS WITH AFFILIATED COMPANIES-

Operating revenues, operating expenses and other income included transactions with affiliated companies, primarily FESC, GPUS and FES. GPUS (until it ceased operations in mid-2003) and FESC have provided legal, accounting, financial and other corporate support services to the Company. The Company also entered into sale and purchase transactions with affiliates (JCP&L and Met-Ed) during 2002. Effective September 1, 2002, the Company purchases a portion of its PLR responsibility from FES through a wholesale power sale agreement. The primary affiliated companies transactions are as follows:

	2004	2003	2002
		(In millions)	
Operating Revenues:			
Wholesale sales–affiliated companies	$ –	$ –	$ 9
Operating Expenses:			
Power purchased from FES	404	307	188
Service Company support services	45	55	82
Power purchased from other affiliates	–	5	10

FirstEnergy does not bill directly or allocate any of its costs to any subsidiary company. Costs are allocated to the Company from FESC, a subsidiary of FirstEnergy and a "mutual service company" as defined in Rule 93 of the PUHCA. The vast majority of costs are directly billed or assigned at no more than cost as determined by PUHCA Rule 91. The remaining costs are for services that are provided on behalf of more than one company, or costs that cannot be precisely identified and are allocated using formulas that are filed annually with the SEC on Form U-13-60. The current allocation or assignment formulas used and their bases include multiple factor formulas; each company's proportionate amount of FirstEnergy's aggregate total for direct payroll, number of employees, asset balances, revenues, number of customers, other factors and specific departmental charge ratios. It is management's belief that allocation methods utilized are reasonable. Intercompany transactions with FirstEnergy and its other subsidiaries are generally settled under commercial terms within thirty days, except for a net $45 million receivable from affiliates for OPEB obligations.

3. PENSION AND OTHER POSTRETIREMENT BENEFIT PLANS:

FirstEnergy provides noncontributory defined benefit pension plans that cover substantially all of the Company's employees. The trusteed plans provide defined benefits based on years of service and compensation levels. The Company's funding policy is based on actuarial computations using the projected unit credit method. In the third quarter of 2004, FirstEnergy made a $500 million voluntary contribution to its pension plan (Company's share was $50 million). Prior to this contribution, projections indicated that cash contributions of approximately $600 million would have been required during the 2006 to 2007 time period under minimum funding requirements established by the IRS. The election to pre-fund the plan is expected to eliminate that funding requirement. Since the contribution is deductible for tax purposes, the after-tax cash impact of the voluntary contribution is approximately $300 million (the Company's share was $30 million).

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

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

Unless otherwise indicated, the following tables provide information applicable to FirstEnergy's pension and OPEB plans.

Obligations and Funded Status As of December 31	Pension Benefits 2004	Pension Benefits 2003	Other Benefits 2004	Other Benefits 2003
		(In millions)		
Change in benefit obligation				
Benefit obligation as of January 1	$ 4,162	$ 3,866	$ 2,368	$ 2,077
Service cost	77	66	36	43
Interest cost	252	253	112	136
Plan participants' contributions	–	–	14	6
Plan amendments	–	–	(281)	(123)
Actuarial (gain) loss	134	222	(211)	323
Benefits paid	(261)	(245)	(108)	(94)
Benefit obligation as of December 31	$ 4,364	$ 4,162	$ 1,930	$ 2,368
Change in fair value of plan assets				
Fair value of plan assets as of January 1	$ 3,315	$ 2,889	$ 537	$ 473
Actual return on plan assets	415	671	57	88
Company contribution	500	–	64	68
Plan participants' contribution	–	–	14	2
Benefits paid	(261)	(245)	(108)	(94)
Fair value of plan assets as of December 31	$ 3,969	$ 3,315	$ 564	$ 537
Funded status	$ (395)	$ (847)	$ (1,366)	$ (1,831)
Unrecognized net actuarial loss	885	919	730	994
Unrecognized prior service cost (benefit)	63	72	(378)	(221)
Unrecognized net transition obligation	–	–	–	83
Net asset (liability) recognized	$ 553	$ 144	$ (1,014)	$ (975)
Amounts Recognized in the Consolidated Balance Sheets As of December 31				
Accrued benefit cost	$ (14)	$ (438)	$ (1,014)	$ (975)
Intangible assets	63	72	–	–
Accumulated other comprehensive loss	504	510	–	–
Net amount recognized	$ 553	$ 144	$ (1,014)	$ (975)
Company's share of net amount recognized	$ 64	$ 14	$ (92)	$ (86)
Increase (decrease) in minimum liability included in other comprehensive income (net of tax)	$ (4)	$ (145)	–	–
Assumptions Used to Determine Benefit Obligations As of December 31				
Discount rate	6.00%	6.25%	6.00%	6.25%
Rate of compensation increase	3.50%	3.50%		
Allocation of Plan Assets As of December 31 **Asset Category**				
Equity securities	68%	70%	74%	71%
Debt securities	29	27	25	22
Real estate	2	2	–	–
Cash	1	1	1	7
Total	100%	100%	100%	100%

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

Components of Net Periodic Benefit Costs	Pension Benefits 2004	Pension Benefits 2003	Pension Benefits 2002	Other Benefits 2004	Other Benefits 2003	Other Benefits 2002
			(In millions)			
Service cost	$ 77	$ 66	$ 59	$ 36	$ 43	$ 29
Interest cost	252	253	249	112	137	114
Expected return on plan assets	(286)	(248)	(346)	(44)	(43)	(52)
Amortization of prior service cost	9	9	9	(40)	(9)	3
Amortization of transition obligation (asset)	–	–	–	–	9	9
Recognized net actuarial loss	39	62	–	39	40	11
Net periodic cost (income)	$ 91	$ 142	$ (29)	$ 103	$ 177	$ 114
Company's share of net periodic cost (income)	$ –	$ 7	$ (16)	$ 3	$ 10	$ 3

Weighted-Average Assumptions Used to Determine Net Periodic Benefit Cost for Years Ended December 31	Pension Benefits 2004	Pension Benefits 2003	Pension Benefits 2002	Other Benefits 2004	Other Benefits 2003	Other Benefits 2002
Discount rate	6.25%	6.75%	7.25%	6.25%	6.75%	7.25%
Expected long-term return on plan assets	9.00%	9.00%	10.25%	9.00%	9.00%	10.25%
Rate of compensation increase	3.50%	3.50%	4.00%			

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

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

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

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

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

Pursuant to FSP 106-1 issued January 12, 2004, FirstEnergy began accounting for the effects of the Medicare Act effective January 1, 2004 because of a plan amendment during the quarter, which required remeasurement of the plan's obligations. The plan amendment, which increases cost-sharing by employees and retirees effective January 1, 2005, reduced the Company's postretirement benefit costs by $2 million during 2004.

Consistent with the guidance in FSP 106-2 issued on May 19, 2004, FirstEnergy recognized a reduction of $318 million in the accumulated postretirement benefit obligation as a result of the federal subsidy provided under the Medicare Act related to benefits for past service. This reduction was accounted for as an actuarial gain in 2004 pursuant to FSP 106-2. The subsidy reduced the Company's net periodic postretirement benefit costs by $5 million during 2004.

As a result of its voluntary contribution and the increased market value of pension plan assets, the Company reduced its accrued benefit cost as of December 31, 2004 by $32 million. As prescribed by SFAS 87, the Company increased its additional minimum liability by $18 million, offset by a charge to OCI. The balance in AOCL of $52 million (net of $37 million in deferred taxes) will reverse in future periods to the extent the fair value of trust assets exceeds the accumulated benefit obligation.

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

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

4. FAIR VALUE OF FINANCIAL INSTRUMENTS:

Long-term Debt and Other Long-term Obligations-

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

	2004		2003	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	(In millions)			
Long-term debt	$ 491	$ 521	$ 468	$ 508
Subordinated debentures to affiliated trusts	–	–	96	104
	$ 491	$ 521	$ 564	$ 612

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 Company's ratings.

Investments-

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

	2004		2003	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	(In millions)			
Debt securities: [1]				
–Government obligations	$ 146	$ 146	$ 92	$ 92
–Corporate debt securities	–	–	1	1
	146	146	93	93
Equity securities [1]	62	62	56	56
	$ 208	$ 208	$ 149	$ 149

[1] Includes nuclear decommissioning and NUG trust investments.

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 Company has no securities held for trading purposes. The following table summarizes the amortized cost basis, gross unrealized gains and losses and fair values for decommissioning trust investments as of December 31:

	2004				2003			
	Cost Basis	Unrealized Gains	Unrealized Losses	Fair Value	Cost Basis	Unrealized Gains	Unrealized Losses	Fair Value
	(In millions)							
Debt securities	$ 49	$ 1	$ –	$ 50	$ 47	$ 2	$ –	$ 49
Equity securities	55	7	2	60	36	18	–	54
	$ 104	$ 8	$ 2	$ 110	$ 83	$ 20	$ –	$ 103

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

	2004	2003	2002
		(In millions)	
Proceeds from sales	$102	$ 41	$24
Gross realized gains	18	1	–
Gross realized losses	–	–	–
Interest and dividend income	3	3	3

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

	Less Than 12 Months		12 Months or More		Total	
	Fair Value	Unrealized Losses	Fair Value	Unrealized Losses	Fair Value	Unrealized Losses
			(In millions)			
Debt securities	$ 8	$ –	$ 4	$ –	$ 12	$ –
Equity securities	13	2	–	–	13	2
	$ 21	$ 2	$ 4	$ –	$ 25	$ 2

The Company periodically evaluates the securities held by its nuclear decommissioning trusts for other-than-temporary impairment. The Company 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 an impairment is other than temporary. The recovery of amounts contributed to the Company's decommissioning trusts are subject to regulatory accounting in accordance with SFAS 71. Net unrealized gains and losses are recorded as regulatory liabilities or assets since the difference between investments held in trust and the decommissioning liabilities are recovered from or refunded to customers.

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

5. LEASES:

Consistent with regulatory treatment, the rentals for capital leases are charged to operating expenses on the Consolidated Statements of Income. The Company has a capital lease for a building that expires in 2005. In 2004, total rentals related to this capital lease were $0.5 million. In each of 2003 and 2002, total rentals related to this capital lease were $0.7 million, comprised of an interest element of $0.1 million and other costs of $0.6 million.

As of December 31, 2004, the future minimum lease payments on the Company's capital lease discussed above are $40,000 for the year 2005.

6. VARIABLE INTEREST ENTITIES:

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

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

The Company has determined that for all but two of these entities, the Company has no variable interests in the entities or the entities are governmental or not-for-profit organizations not within the scope of FIN 46R. The Company may hold variable interests in the remaining two 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, the Company requests on a quarterly basis, the information necessary from these entities to determine whether they are VIEs or whether the Company is the primary beneficiary. The Company has been unable to obtain the requested information, which was deemed by the requested entity to be proprietary. As such, the Company applied the scope exception that exempts enterprises unable to obtain the necessary information to evaluate entities under FIN 46R. The maximum exposure to loss from these entities results from increases in the variable pricing component under the contract terms and cannot be determined without the requested data. The purchased power costs from these entities during 2004, 2003 and 2002 were $27 million, $27 million and $24 million, respectively.

7. REGULATORY MATTERS:

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

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

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

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

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

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

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

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

On January 12, 2005, the Company filed, before the PPUC, a request for deferral of transmission-related costs beginning January 1, 2005, estimated to be approximately $4 million per month. Various parties have intervened in this case.

8. CAPITALIZATION:

(A) RETAINED EARNINGS-

In general, the Company's FMB indentures restrict the payment of dividends or distributions on or with respect to the Company's common stock to amounts credited to earned surplus since the date of its indenture. As of December 31, 2004, the Company had retained earnings available to pay common stock dividends of $36.0 million, net of amounts restricted under the Company's FMB indentures.

(B) PREFERRED STOCK-

The Company's preferred stock authorization consists of 11.435 million shares without par value. No preferred shares are currently outstanding.

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

Subordinated Debentures to Affiliated Trust

The Company had formed a statutory business trust to sell preferred securities and invest the gross proceeds in subordinated debentures. Ownership of the Company's trust had been through a separate wholly owned limited partnership. In this transaction, the trust had invested the gross proceeds from the sale of its preferred securities in the preferred securities of the limited partnership, which in turn invested those proceeds in the 7.34% subordinated debentures of the Company. On September 1, 2004, the Company extinguished the subordinated debentures held by its affiliated trust and redeemed all of the associated 7.34% preferred securities (aggregate value of $100 million).

Other Long-term Debt

The Company's FMB indenture, which secures all of the Company's FMBs, serve as a direct first mortgage lien on substantially all of the Company's property and franchises, other than specifically excepted property.

The Company has various debt covenants under its financing arrangements. The most restrictive of these relate to the nonpayment of interest and/or principal on debt, which could trigger a default. Cross-default provisions also exist between FirstEnergy and the Company.

Based on the amount of bonds authenticated by the Trustee through December 31, 2004, the Company's annual sinking fund requirements for all bonds issued under the mortgage amount to approximately $1 million. The Company expects to fulfill its sinking fund obligation by providing bondable property additions to the Trustee.

Sinking fund requirements for FMB and maturing long-term debt for the next five years are:

	(In millions)
2005	$ 8
2006	–
2007	3
2008	–
2009	100

The Company's 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 noncancelable municipal bond insurance policies of $69 million to pay principal of, or interest on, the pollution control revenue bonds.

9. ASSET RETIREMENT OBLIGATION:

In January 2003, the Company implemented SFAS 143, which provides accounting standards for retirement obligations associated with tangible long-lived assets. This statement 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 asset retirement liability 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.

The Company identified applicable legal obligations as defined under the new standard for nuclear power plant decommissioning. The ARO liability as of the date of adoption of SFAS 143 was $99.1 million, including accumulated accretion for the period from the date the liability was incurred to the date of adoption. As of December 31, 2002, the Company recognized decommissioning liabilities of $129.9 million. The Company expects substantially all nuclear decommissioning costs to be recoverable through regulated rates. Therefore, a regulatory liability of $30.8 million was recognized upon adoption of SFAS 143. The ARO includes the Company's obligation for nuclear decommissioning of TMI-2. The Company's share of the obligation to decommission TMI-2 was developed based on a site-specific study performed by an independent engineer. The Company utilized an expected cash flow approach to measure the fair value of the nuclear decommissioning ARO. The Company maintains nuclear decommissioning trust funds that are legally restricted for purposes of settling the nuclear decommissioning ARO. As of December 31, 2004, the fair value of the decommissioning trust assets was $110 million.

In the third quarter of 2004, the Company revised the ARO associated with TMI-2 as the result of a recently completed study and the anticipated operating license extension for TMI-1. The abandoned TMI-2 is adjacent to TMI-1 and the units are expected to be decommissioned concurrently. The net decrease in the Company's TMI-2 ARO liability and corresponding regulatory asset was $44 million.

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

ARO Reconciliation	**2004**	**2003**
	(In millions)	
Beginning balance as of January 1	$ 105	$ 99
Accretion	5	6
Revisions in estimated cash flows	(44)	–
Ending balance as of December 31	$ 66	$ 105

The following table provides the year-end balance of the ARO for 2002, as if SFAS 143 had been adopted on January 1, 2002.

Adjusted ARO Reconciliation	2002 (In millions)
Beginning balance as of January 1	$ 93
Accretion	6
Ending balance as of December 31	$ 99

10. SHORT-TERM BORROWINGS:

The Company may borrow from its affiliates on a short-term basis. As of December 31, 2004, the Company had total short-term borrowings of $241.5 million from its affiliates. The weighted average interest rates on short-term borrowings outstanding at December 31, 2004 and 2003 were 2.0% and 1.7%, respectively.

The Company has a receivables financing agreement under which the Company can borrow up to an aggregate of $75 million at rates based on certain bank commercial paper and is required to pay an annual facility fee of 0.30% on the entire finance limit. This financing agreement expires on March 29, 2005. These receivables financing arrangements are expected to be renewed prior to expiration.

11. 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. Based on its present ownership interest in TMI-2, the Company is exempt from any potential assessment under the industry retrospective rating plan.

The Company is also insured as to its interest in TMI-2 under a policy issued to the operating company for the plant. Under this policy, $150 million is provided for property damage and decontamination and decommissioning costs. Under this policy, the Company can be assessed a maximum of approximately $0.2 million for incidents at any covered nuclear facility occurring during a policy year which are in excess of accumulated funds available to the insurer for paying losses.

The Company intends to maintain insurance against nuclear risks as described above as long as it is available. To the extent that property damage, decontamination, decommissioning, repair and replacement costs and other such costs arising from a nuclear incident at TMI-2 exceed the policy limits of the insurance in effect with respect to that plant, to the extent a nuclear incident is determined not to be covered by the Company's insurance policies, or to the extent such insurance becomes unavailable in the future, the Company would remain at risk for such costs.

(B) ENVIRONMENTAL MATTERS-

The Company has been named as a PRP 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. The Company accrues environmental liabilities only when it concludes that it is probable that an obligation for such costs exists and can reasonably determine the amount of such costs. Unasserted claims are reflected in the Company's determination of environmental liabilities and are accrued in the period that they are both probable and reasonably estimable.

(C) OTHER LEGAL PROCEEDINGS-

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

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 instituted against the Companies. In particular, if FirstEnergy or its subsidiaries were ultimately determined to have legal liability in connection with these proceedings, it could have a material adverse effect on FirstEnergy's or its subsidiaries' financial condition and results of operations.

Legal Matters

Various lawsuits, claims (including claims for asbestos exposure) and proceedings related to the Company's normal business operations are pending against the Company, the most significant of which are described above.

12. NEW ACCOUNTING STANDARDS AND INTERPRETATIONS:

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

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

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

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

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

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

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

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

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

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

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

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

14. SUMMARY OF QUARTERLY FINANCIAL DATA (UNAUDITED):

The following summarizes certain consolidated operating results by quarter for 2004 and 2003:

Three Months Ended	March 31, 2004	June 30, 2004	September 30, 2004	December 31, 2004
		(In millions)		
Operating Revenues	$ 256.4	$ 242.2	$ 254.3	$ 283.1
Operating Expenses and Taxes	240.9	229.3	226.9	265.3
Operating Income	15.5	12.9	27.4	17.8
Other Income	–	0.4	1.3	0.7
Net Interest Charges	9.8	10.2	10.5	9.4
Net Income	$ 5.7	$ 3.1	$ 18.2	$ 9.1

Three Months Ended	March 31, 2003	June 30, 2003	September 30, 2003	December 31, 2003
		(In millions)		
Operating Revenues	$ 254.9	$ 231.9	$ 242.1	$ 245.9
Operating Expenses and Taxes	242.2	215.6	228.5	228.3
Operating Income	12.7	16.3	13.6	17.6
Other Income (Expense)	(0.2)	0.5	0.5	1.0
Net Interest Charges	8.3	8.1	9.0	16.4
Income Before Cumulative Effect of Accounting Change	4.2	8.7	5.1	2.2
Cumulative Effect of Accounting Change (Net of Income Taxes)	1.1	–	–	–
Net Income	$ 5.3	$ 8.7	$ 5.1	$ 2.2

FirstEnergy®

c/o FirstEnergy Corp.
76 South Main Street
Akron, Ohio 44308
(800) 736-3402

2004 Annual Report

FirstEnergy®

Form 10-K

ANNUAL REPORT TO THE SECURITIES AND EXCHANGE COMMISSION

For the Year Ended December 31, 2004

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D. C. 20549

FORM 10-K

(Mark One)

[X] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2004
OR
[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from ______________ to ______________

Commission File Number	Registrant; State of Incorporation; Address; and Telephone Number	I.R.S. Employer Identification No.
333-21011	FIRSTENERGY CORP. (An Ohio Corporation) 76 South Main Street Akron, OH 44308 Telephone (800)736-3402	34-1843785
1-2578	OHIO EDISON COMPANY (An Ohio Corporation) c/o FirstEnergy Corp. 76 South Main Street Akron, OH 44308 Telephone (800)736-3402	34-0437786
1-2323	THE CLEVELAND ELECTRIC ILLUMINATING COMPANY (An Ohio Corporation) c/o FirstEnergy Corp. 76 South Main Street Akron, OH 44308 Telephone (800)736-3402	34-0150020
1-3583	THE TOLEDO EDISON COMPANY (An Ohio Corporation) c/o FirstEnergy Corp. 76 South Main Street Akron, OH 44308 Telephone (800)736-3402	34-4375005
1-3491	PENNSYLVANIA POWER COMPANY (A Pennsylvania Corporation) c/o FirstEnergy Corp. 76 South Main Street Akron, OH 44308 Telephone (800)736-3402	25-0718810
1-3141	JERSEY CENTRAL POWER & LIGHT COMPANY (A New Jersey Corporation) c/o FirstEnergy Corp. 76 South Main Street Akron, OH 44308 Telephone (800)736-3402	21-0485010
1-446	METROPOLITAN EDISON COMPANY (A Pennsylvania Corporation) c/o FirstEnergy Corp. 76 South Main Street Akron, OH 44308 Telephone (800)736-3402	23-0870160
1-3522	PENNSYLVANIA ELECTRIC COMPANY (A Pennsylvania Corporation) c/o FirstEnergy Corp. 76 South Main Street Akron, OH 44308 Telephone (800)736-3402	25-0718085

SECURITIES REGISTERED PURSUANT TO SECTION 12(b) OF THE ACT:

Registrant	Title of Each Class	Name of Each Exchange on Which Registered
FirstEnergy Corp.	Common Stock, $0.10 par value	New York Stock Exchange
Ohio Edison Company	Cumulative Preferred Stock, $100 par value: 3.90% Series 4.40% Series 4.44% Series 4.56% Series	All series registered on New York Stock Exchange and Chicago Stock Exchange
The Cleveland Electric Illuminating Company	Cumulative Serial Preferred Stock, without par value: $7.40 Series A Adjustable Rate, Series L	Both series registered on New York Stock Exchange
The Toledo Edison Company	Cumulative Preferred Stock, par value $100 per share: 4-1/4% Series	American Stock Exchange
	Cumulative Preferred Stock, par value $25 per share: $2.365 Series Adjustable Rate, Series A Adjustable Rate, Series B	All series registered on New York Stock Exchange
Pennsylvania Power Company	Cumulative Preferred Stock, $100 par value: 4.24% Series 4.25% Series 4.64% Series	All series registered on Philadelphia Stock Exchange
Jersey Central Power & Light Company	Cumulative Preferred Stock, without par value: 4% Series	New York Stock Exchange

SECURITIES REGISTERED PURSUANT TO SECTION 12(g) OF THE ACT:

None

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days: Yes (X) No ( )

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K.

(X) FirstEnergy Corp.
( ) Ohio Edison Company, Pennsylvania Power Company, The Cleveland Electric Illuminating Company, The Toledo Edison Company, Jersey Central Power & Light Company, Metropolitan Edison Company and Pennsylvania Electric Company.

Indicate by check mark whether each registrant is an accelerated filer (as defined in Rule 12b-2 of the Act):

Yes (X) No ( ) FirstEnergy Corp.
Yes ( ) No (X) Ohio Edison Company, Pennsylvania Power Company, The Cleveland Electric Illuminating Company, The Toledo Edison Company, Jersey Central Power & Light Company, Metropolitan Edison Company, and Pennsylvania Electric Company

State the aggregate market value of the common stock held by non-affiliates of the registrants: FirstEnergy Corp., $12,315,809,435 as of June 30, 2004; and for all other registrants, none.

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of the latest practicable date:

CLASS	OUTSTANDING As of March 9, 2005
FirstEnergy Corp., $0.10 par value	329,836,276
Ohio Edison Company, no par value	100
The Cleveland Electric Illuminating Company, no par value	79,590,689
The Toledo Edison Company, $5 par value	39,133,887
Pennsylvania Power Company, $30 par value	6,290,000
Jersey Central Power & Light Company, $10 par value	15,371,270
Metropolitan Edison Company, no par value	859,500
Pennsylvania Electric Company, $20 par value	5,290,596

FirstEnergy Corp. is the sole holder of Ohio Edison Company, The Cleveland Electric Illuminating Company, The Toledo Edison Company, Jersey Central Power & Light Company, Metropolitan Edison Company, and Pennsylvania Electric Company common stock; Ohio Edison Company is the sole holder of Pennsylvania Power Company common stock.

Documents incorporated by reference (to the extent indicated herein):

DOCUMENT	PART OF FORM 10-K INTO WHICH DOCUMENT IS INCORPORTED
FirstEnergy Corp. Annual Report to Stockholders for the fiscal year ended December 31, 2004 (Pages 4-85)	Part II
Proxy Statement for 2005 Annual Meeting of Stockholders to be held May 17, 2005	Part III

This combined Form 10-K is separately filed by FirstEnergy Corp., Ohio Edison Company, Pennsylvania Power Company, The Cleveland Electric Illuminating Company, The Toledo Edison Company, Jersey Central Power & Light Company, Metropolitan Edison Company and Pennsylvania Electric Company. Information contained herein relating to any individual registrant is filed by such registrant on its own behalf. No registrant makes any representation as to information relating to any other registrant, except that information relating to any of the seven FirstEnergy subsidiary registrants is also attributed to FirstEnergy.

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
Companies	OE, CEI, TE, Penn, JCP&L, Met-Ed and Penelec defined on page 1
EUOC	Electric Utility Operating Companies (OE, CEI, TE, Penn, JCP&L, Met-Ed, Penelec, and ATSI)
FENOC	FirstEnergy Nuclear Operating Company, operates nuclear generating facilities
FES	FirstEnergy Solutions Corp., provides energy-related products and services
FESC	FirstEnergy Service Company, provides legal, financial, and other corporate support services
FGCO	FirstEnergy Generation Corp., operates nonnuclear generating facilities
FirstCom	First Communications, LLC, provides local and long-distance telephone service
FirstEnergy	FirstEnergy Corp., a registered public utility holding company
FSG	FirstEnergy Facilities Services Group, LLC, the parent company of several heating, ventilation,air conditioning and energy management companies
GLEP [1]	Great Lakes Energy Partners, LLC, an oil and natural gas exploration and production venture
GPU	GPU, Inc., former parent of JCP&L, Met-Ed and Penelec, which merged with FirstEnergy on November 7, 2001
JCP&L	Jersey Central Power & Light Company, a New Jersey electric utility operating subsidiary
Met-Ed	Metropolitan Edison Company, a Pennsylvania electric utility operating subsidiary
MYR	MYR Group, Inc., a utility infrastructure construction service company
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
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:

AEP	American Electric Power Company, Inc.
ALJ	Administrative Law Judge
ASLB	Atomic Safety and Licensing Board
BGS	Basic Generation Service
CO_2	Carbon Dioxide
CTC	Competitive Transition Charge
DPL	Dayton Power & Light Company
ECAR	East Central Area Reliability Coordination Agreement
EPA	Environmental Protection Agency only in various other terms
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FIN	FASB Interpretation
FIN 46	FIN 46 "Consolidation of Variable Interest Entities"
FMB	First Mortgage Bonds
HVAC	Heating, Ventilation and Air-conditioning
IBEW	International Brotherhood of Electrical Workers
MACT	Maximum Achievable Control Technologies
MEC	Michigan Electric Coordination Systems
MISO	Midwest Independent Transmission System Operator, Inc.
MTC	Market Transition Charge
MW	Megawatts
NAAQS	National Ambient Air Quality Standards
NERC	North American Electric Reliability Council
NEIL	Nuclear Electric Insurance Limited
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 Generator

GLOSSARY OF TERMS, Cont.

NYSE	New York Stock Exchange
OCC	Ohio Consumers' Counsel
PJM	Pennsylvania-New Jersey-Maryland Interconnection LLC
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
S&P	Standard & Poor's Ratings Service
SBC	Societal Benefits Charge
SEC	United States Securities and Exchange Commission
SFAS	Statement of Financial Accounting Standards
SFAS 71	SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation"
SFAS 101	SFAS No. 101, "Accounting for Discontinuation of Application of SFAS 71"
SO_2	*Sulfur Dioxide*
TMI-2	Three Mile Island Unit 2

FORM 10-K

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PART I

ITEM 1. BUSINESS

The Company

FirstEnergy Corp. was organized under the laws of the State of Ohio in 1996. 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. These utility operating subsidiaries are referred to throughout as the "Companies." FirstEnergy's consolidated revenues are primarily derived from electric service provided by its utility operating subsidiaries and the revenues of its other principal subsidiaries: FES; FSG; MYR; and FirstCom. In addition, FirstEnergy holds all of the outstanding common stock of other direct subsidiaries including: FirstEnergy Properties, Inc., FirstEnergy Ventures Corp., FENOC, FirstEnergy Securities Transfer Company, GPU Diversified Holdings, LLC, GPU Telecom Services, Inc., GPU Nuclear, Inc.; and FESC.

The Companies' combined service areas encompass approximately 36,100 square miles in Ohio, New Jersey and Pennsylvania. The areas they serve have a combined population of approximately 11.2 million.

OE was organized under the laws of the State of Ohio in 1930 and owns property and does business as an electric public utility in that state. OE also has ownership interests in certain generating facilities located in the Commonwealth of Pennsylvania (see Item 2 – Properties). OE engages in the generation, distribution and sale of electric energy to communities in a 7,500 square mile area of central and northeastern Ohio. OE also engages in the sale, purchase and interchange of electric energy with other electric companies. The area it serves has a population of approximately 2.8 million.

OE owns all of Penn's outstanding common stock. Penn was organized under the laws of the Commonwealth of Pennsylvania in 1930 and owns property and does business as an electric public utility in that state. Penn is also authorized to do business and owns property in the State of Ohio (see Item 2 – Properties). Penn furnishes electric service to communities in a 1,500 square mile area of western Pennsylvania. The area served by Penn has a population of approximately 0.3 million.

CEI was organized under the laws of the State of Ohio in 1892 and does business as an electric public utility in that state. CEI engages in the generation, distribution and sale of electric energy in an area of approximately 1,700 square miles in northeastern Ohio. It also has ownership interests in certain generating facilities in Pennsylvania (see Item 2 – Properties). CEI also engages in the sale, purchase and interchange of electric energy with other electric companies. The area CEI serves has a population of approximately 1.9 million.

TE was organized under the laws of the State of Ohio in 1901 and does business as an electric public utility in that state. TE engages in the generation, distribution and sale of electric energy in an area of approximately 2,500 square miles in northwestern Ohio. It also has interests in certain generating facilities in Pennsylvania (see Item 2 – Properties). TE also engages in the sale, purchase and interchange of electric energy with other electric companies. The area TE serves has a population of approximately 0.8 million.

ATSI was organized under the laws of the State of Ohio in 1998. ATSI owns transmission assets that were formerly owned by the Ohio Companies and Penn. ATSI owns and operates major, high-voltage transmission facilities, which consist of approximately 7,100 circuit miles (5,814 pole miles) of transmission lines with nominal voltages of 345 kV, 138 kV and 69 kV. There are 37 interconnections with six neighboring control areas. ATSI's transmission system offers gateways into the East through high capacity ties with PJM through Penelec, Duquesne Light Company and Allegheny Energy, Inc. into the North through multiple 345 kV high capacity ties with MEC, and into the South through ties with AEP and DPL. ATSI is the control area operator for the Ohio Companies and Penn service areas. ATSI plans, operates and maintains the transmission system in accordance with the requirements of the NERC and applicable regulatory agencies to ensure reliable service to FirstEnergy's customers (see Transmission Rate Matters for a discussion of ATSI's participation in the MISO).

JCP&L was organized under the laws of the State of New Jersey in 1925 and owns property and does business as an electric public utility in that state. JCP&L provides transmission and distribution services in northern, western and east central New Jersey. The area JCP&L serves has a population of approximately 2.5 million.

Met-Ed was organized under the laws of the Commonwealth of Pennsylvania in 1922 and owns property and does business as an electric public utility in that state. Met-Ed provides primarily transmission and distribution services in eastern and south central Pennsylvania. The area it serves has a population of approximately 1.2 million.

Penelec was organized under the laws of the Commonwealth of Pennsylvania in 1919 and owns property and does business as an electric public utility in that state. Penelec provides transmission and distribution services in western, northern and south central Pennsylvania. The area it serves has a population of approximately 1.7 million. Penelec, as lessee of the property of its subsidiary, The Waverly Electric Light & Power Company, also serves a population of about 13,400 in Waverly, New York and its vicinity.

FES was organized under the laws of the State of Ohio in 1997 and provides energy-related products and services, and through its FGCO subsidiary, operates FirstEnergy's nonnuclear generation businesses. FENOC was organized under the laws of the State of Ohio in 1998 and operates the Companies' nuclear generating facilities. FSG is the parent company of several HVAC and energy management companies; MYR is a utility infrastructure construction service company. FirstCom provides telecommunication services (local and long-distance phone service). FESC provides legal, financial and other corporate support services to affiliated FirstEnergy companies.

Divestitures

FirstEnergy completed the sale of its international operations in January 2004 with the sales of its remaining 20.1 percent interest in Avon on January 16, 2004, and 28.67 percent interest in TEBSA on January 30, 2004. Impairment charges related to Avon and TEBSA were recorded in the fourth quarter of 2003 and no gain or loss was recognized upon the sales in 2004. Avon, TEBSA and other international assets sold in 2003 were originally acquired as part of FirstEnergy's November 2001 merger with GPU.

FirstEnergy sold its 50 percent interest in GLEP on June 23, 2004. Proceeds of $220 million included cash of $200 million and the right, valued at $20 million, to participate for up to a 40% interest in future wells in Ohio. This transaction produced an after-tax loss of $7 million, or $0.02 per share of common stock, including the benefits of prior tax capital losses that had been previously fully reserved, which offset the capital gain from the sale.

Risks Factors That May Affect Results

Changes in Commodity Prices Could Adversely Affect Our Margins

While much of our generation serves customers under retail rates set by regulatory bodies, we also purchase and sell electricity in the competitive wholesale and retail markets. Increases in the costs of fuel for our generation facilities (particularly coal and natural gas) can affect our profit margins in both competitive and non-competitive markets. Changes in the market prices of electricity, which are affected by changes in fuel costs and other factors, may impact our financial results and financial position by increasing the amount we pay to purchase power to supply PLR obligations in Ohio and Pennsylvania.

Electricity and fuel prices may fluctuate substantially over relatively short periods of time for a variety of reasons, including:

- severe or unexpected weather or seasonality;
- changes in electricity usage;
- illiquidity in wholesale power and other markets;
- transmission or transportation constraints, inoperability or inefficiencies;
- availability of competitively priced alternative energy sources;
- changes in supply and demand for energy commodities;
- changes in power production capacity;
- outages at our power production facilities or those of our competitors;
- changes in production and storage levels of natural gas, lignite, coal, crude oil and refined products;
- natural disasters, wars, acts of sabotage, terrorist acts, embargoes and other catastrophic events; and

Complex and Changing Government Regulations Could Have a Negative Impact on Our Results of Operations

We are subject to comprehensive regulation by various federal, state and local regulatory agencies that significantly influences our operating environment. Changes in or reinterpretations of existing laws or regulations or the imposition of new laws or regulations could require us to incur additional costs or change the way we conduct our business, and therefore could have an adverse impact on our results of operations.

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 are required to have numerous permits, approvals and certificates from the agencies that regulate our business. We believe the necessary permits, approvals and certificates have been obtained for our existing operations and that our business is conducted in accordance with applicable laws; however, we are unable to predict the impact on operating results from future regulatory activities of any of these agencies.

Costs of Compliance with Environmental Laws are Significant, and the Cost of Compliance with Future Environmental Laws Could Adversely Affect Cash Flow and Profitability

FirstEnergy's subsidiaries' operations are subject to extensive federal, state and local environmental statutes, rules and regulations. Compliance with these legal requirements requires us to incur significant costs toward environmental monitoring, installation of pollution control equipment, emission fees, maintenance, upgrading, remediation and permitting at all of our facilities. These expenditures have been significant in the past and may increase in the future. If the cost of compliance with existing environmental laws and regulations does increase, it could adversely affect our business and results of operations, financial position and cash flows. Moreover, changes in environmental laws or regulations may materially increase our costs of compliance or accelerate the timing of capital expenditures. Because of the deregulation of generation, we might not recover through rates additional costs incurred for such compliance. Our compliance strategy, although reasonably based on available information, may not successfully address the relevant standards and interpretations in the future. If FirstEnergy fails to comply with environmental laws and regulations, even if caused by factors beyond its control or new interpretations of longstanding requirements, that failure may result in the assessment of civil or criminal liability and fines.

Risks of Nuclear Generation that Include Uncertainties Relating to Health and Safety, Additional Capital Costs, the Adequacy of Insurance Coverage and Nuclear Plant Decommissioning

FirstEnergy is subject to the risks of nuclear generation, including but not limited to the following:

- the potential harmful effects on the environment and human health resulting from the operation of nuclear facilities and the storage, handling and disposal of radioactive materials;
- limitations on the amounts and types of insurance commercially available to cover losses that might arise in connection with our nuclear operations or those of others in the United States;
- uncertainties with respect to contingencies and assessment amounts if insurance coverage is inadequate; and
- uncertainties with respect to the technological and financial aspects of decommissioning nuclear plants at the end of their licensed operation.

The NRC has broad authority under federal law to impose licensing and safety-related requirements for the operation of nuclear generation facilities. In the event of non-compliance, the NRC has the authority to impose fines or shut down a unit, or both, depending upon its assessment of the severity of the situation, until compliance is achieved. Revised safety requirements promulgated by the NRC could necessitate substantial capital expenditures at nuclear plants, including ours. Unlike our fossil plants, which have been leased to and operated by FGCO since 2001, new capital costs as well as fuel, operation and maintenance expenses for the nuclear plants continue to be borne by CEI, TE, OE and Penn.

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

Operational Risks Arising from the Reliability of Our Power Plants and Transmission and Distribution Equipment

Operation of power plants, transmission and distribution facilities involves many risks, including the breakdown or failure of equipment or processes, accidents, labor disputes, stray voltage and performance below expected levels. In addition, weather-related incidents and other natural disasters can disrupt generation, transmission and distribution delivery systems. Because our transmission facilities are interconnected with those of third parties, the operation of those facilities may be adversely affected by unexpected or uncontrollable events occurring on the systems of such third parties.

Operation of our power plants below expected capacity levels could result in lost revenues or increased expenses, including higher maintenance costs that we may not be able to recover from customers. Unplanned outages may require us to incur significant replacement power costs. Moreover, if we were unable to perform under contractual obligations, penalties or liability for damages may result.

We remain obligated to provide safe and reliable service to customers within our franchised service territories. Meeting this commitment requires significant capital and other resources. Failure to provide safe and reliable service due to equipment failure in the electric system could adversely affect our operating results through reduced revenues and increased capital and maintenance costs.

Human Resource Risks Associated with the Availability of Trained and Qualified Labor to Meet Our Future Staffing Requirements

Workforce demographic issues are a national phenomenon that is of particular concern to the electric utility industry. The median age of utility workers is significantly higher than the national average. Today, nearly one-half of the utility workforce is age 45 or higher. Consequently, the utility industry faces the difficult challenge of finding ways to retain its aging skilled workforce while recruiting new talent in the hopes of decreasing losses in critical knowledge and skills due to retirements. Mitigating these risks may require additional financial commitments.

Regulatory Changes in the Electric Industry Could Affect Our Competitive Position and Result in Unrecoverable Costs Adversely Affecting Our Business and Results of Operations

As a result of the actions taken by state legislative bodies over the last few years, major changes in the electric utility business have occurred and are continuing to take place in parts of the United States, including Ohio, Pennsylvania and New Jersey. These changes have resulted in fundamental alterations in the way integrated utilities conduct their business.

Increased competition resulting from restructuring efforts could have a significant adverse financial impact on FirstEnergy and its subsidiaries and consequently on their results of operations. Increased competition could result in increased pressure to lower prices, including the price of electricity. Retail competition and the unbundling of regulated electric service could have a significant adverse financial impact on us due to potential impairment of assets, a loss of retail customers, lower profit margins or increased costs of capital. We cannot predict the extent and timing of entry by additional competitors into the electric markets.

The FERC and U.S. Congress propose from time to time significant changes in the structure and conduct of the electric utility industry. If the restructuring and deregulation efforts result in increased competition or unrecoverable costs, our business and results of operations may be adversely affected. We cannot predict the extent and timing of further efforts to restructure, deregulate or re-regulate our business or the industry.

Weather Conditions such as Tornadoes, Hurricanes, Storms and Droughts, as Well as Seasonal Temperature Variations

Weather conditions directly influence the demand for electric power. In our service areas, demand for power peaks during the hot summer months, with market prices also typically peaking at that time. As a result, overall operating results may fluctuate on a seasonal and quarterly basis. In addition, we have historically sold less power, and consequently received less revenue, when weather conditions are milder. Severe weather, such as tornadoes, hurricanes, storms and droughts, may cause outages and property damage which may require us to incur additional costs that are generally not insured and that may not be recoverable from customers. The effect of the failure of our facilities to operate as planned, as described above, would be particularly burdensome during a peak demand period.

A Downgrade in Credit Ratings Could Negatively Affect Our Ability to Access Capital

We rely on access to capital markets as a significant source of liquidity for capital requirements not satisfied by cash flows from operations. Any inability to maintain our current credit ratings could affect, particularly during times of uncertainty in the capital markets, our ability to raise capital on favorable terms which, in turn, could impact our ability to grow our businesses. A credit rating downgrade would likely also increase our interest costs.

On July 22, 2004, S&P updated its analysis of U.S. utility FMB in response to changes in the industry. As a result of its revised methodology for evaluating default risk, S&P raised its FMB credit ratings for 20 U.S. utility companies including JCP&L and Penn. JCP&L's FMB credit rating was upgraded to BBB+ from BBB and Penn's FMB credit rating was upgraded to BBB from BBB-.

On August 26, 2004, S&P lowered its rating on certain Met-Ed Senior Notes to BBB- from BBB. The rationale for the ratings change was that Met-Ed's senior secured notes, in aggregate, now comprise greater than 80% of Met-Ed's total debt outstanding. According to the terms of the senior note indenture, once the 80% threshold is reached, the collateral mortgage bond security falls away and all senior secured notes that were secured by Met-Ed's senior note indenture become unsecured. The one notch lower rating reflects this loss of collateral security. The BBB senior secured rating on Met-Ed's FMB remain unchanged.

Also on August 26, 2004, S&P stated that a favorable outcome of the Ohio Rate Stabilization Plan auction process and a favorable resolution of pending environmental litigation would support a higher ratings outlook, or possibly a higher rating. On September 14, 2004, S&P stated that FirstEnergy's $500 million voluntary contribution to its pension plan was credit neutral.

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

Financial Performance Risks Related to the Economic Cycles of the Electric Utility Industry

Our business follows the economic cycles of our customers. Sustained downturns or sluggishness in the economy generally affects the markets in which the Companies operate and negatively influences the Companies' energy operations. Declines in demand for electricity as a result of economic downturns will reduce overall electricity sales and lessen our cash flows, especially as industrial customers reduce production, resulting in less consumption of electricity. Economic conditions also impact our collection rates of accounts receivable.

We May Ultimately Incur Liability in Connection with Federal Proceedings

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, has 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 second subpoena asking for documents relating to issues raised during the SEC's PUHCA examination. FirstEnergy has cooperated fully with the informal inquiry and will continue to do so with the formal investigation. If it were ultimately determined that FirstEnergy or its subsidiaries have legal liability or are otherwise made subject to liability based on any of the above matters, it could have a material adverse effect on FirstEnergy's or its subsidiaries' financial condition and results of operations.

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

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

Utility Regulation

As a registered public utility holding company, FirstEnergy is subject to regulation by the SEC under PUHCA. The SEC has determined that the electric facilities of the Companies constitute a single integrated public utility system under the standards of PUHCA. PUHCA regulates FirstEnergy with respect to accounting, the issuance of securities, the acquisition and sale of utility assets, securities or any other interest in any business, and entering into, and performance of, service, sales and construction contracts among its subsidiaries, and certain other matters. PUHCA also limits the extent to which FirstEnergy may engage in nonutility businesses or acquire additional utility businesses. Each of the Companies' retail rates, conditions of service, issuance of securities and other matters are subject to regulation in the state in which each operates – in Ohio by the PUCO, in New Jersey by the NJBPU and in Pennsylvania by the PPUC. With respect to their wholesale and interstate electric operations and rates, the Companies are subject to regulation, including regulation of their accounting policies and practices, by the FERC. Under Ohio law, municipalities may regulate rates, subject to appeal to the PUCO if not acceptable to the utility.

Regulatory Accounting

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

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

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

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

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

The EUOC recognize, as regulatory assets, costs which the FERC, PUCO, PPUC and NJBPU have authorized for recovery from customers in future periods or for which authorization is probable. Without the probability of such authorization, costs currently recorded as regulatory assets would have been charged to income as incurred. All regulatory assets are expected to be recovered from customers under the Companies' respective transition and regulatory plans. Based on those plans, the Companies continue to bill and collect cost-based rates for their transmission and distribution services, which remain regulated; accordingly, it is appropriate that the Companies continue the application of SFAS 71 to those operations.

Reliability Initiatives

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

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

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

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

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

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

PUCO Rate Matters

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

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

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

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

NJBPU Rate Matters

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

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

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

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

In accordance with an April 28, 2004 NJBPU order, JCP&L filed testimony on June 7, 2004 supporting a continuation of the current level and duration of the funding of TMI-2 decommissioning costs by New Jersey customers without a reduction, termination or capping of the funding. On September 30, 2004, JCP&L filed an updated TMI-2 decommissioning study (see Exhibit 13, Note 11 – Asset Retirement Obligations). This study resulted in an updated total decommissioning cost estimate of $729 million (in 2003 dollars) compared to the estimated $528 million (in 2003 dollars) from the prior 1995 decommissioning study. The Ratepayer Advocate filed comments on February 28, 2008. A schedule for further proceedings has not yet been set.

In response to the ongoing work stoppage by the members of IBEW System Council U-3, the NJBPU has made inquiries of JCP&L regarding its preparedness to assure service reliability and respond to storm or other emergency conditions during the strike. JCP&L has responded to these inquiries and has provided the requested information.

PPUC Rate Matters

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

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

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

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

Transmission Rate Matters

On November 1, 2004, ATSI requested authority from the FERC to defer approximately $54 million of vegetation management costs ($13 deferred as of December 31, 2004 pending authorization) estimated to be incurred from 2004 through 2007. The FERC issued an order granting approval of the deferral on March 2, 2005.

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

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

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

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

PJM and MISO were ordered by the FERC to develop a common market between the regions by October 31, 2004. The FERC also initiated a Section 206 investigation into the reasonableness of the "through-and-out" transmission rates charged by PJM and MISO. By order issued November 17, 2003, as modified by subsequent orders, MISO, PJM, and certain unaffiliated transmission owners in the Midwest were directed to eliminate rates for point-to-point service between the two RTOs effective December 1, 2004. On October 1, 2004, proponents of a Regional Pricing Plan and a Unified Plan filed competing proposals for FERC's consideration. Protests and reply comments were filed with the FERC. On November 18, 2004, FERC issued an order conditionally accepting the Regional Pricing Plan and directing compliance filings by MISO and PJM. On November 24, 2004, compliance filings were submitted to FERC that proposed surcharges for collection of lost revenues in both MISO and PJM for December 1, 2004 through March 31, 2006. Numerous parties protested the proposed surcharges on January 7, 2005. On February 10, 2005, FERC issued an order setting the case for hearing. The outcome of this proceeding cannot be predicted.

On January 31, 2005, certain PJM transmission owners made filings pursuant to a settlement agreement approved by FERC in Docket ER04-156-000. JCP&L, Met-Ed and Penelec were parties to that proceeding. Three filings were made. First, the settling transmission owners submitted a filing justifying continuation of their existing "license plate" rate design within the PJM RTO. Second, 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. Finally, Baltimore Gas & Electric Company and certain public utility affiliates of PEPCO Holdings, Inc. made a filing to implement a transmission cost of service formula rate for their load zones within PJM. JCP&L, Met-Ed and Penelec did not join in this filing. Interventions and protests were due on these filings in late February, and we expect the FERC to act in late March 2005 on the filings.

On August 6, 2004, FERC issued an order conditionally approving the MISO's proposed energy market tariff effective March 1, 2005. FERC affirmed this order on rehearing on November 6, 2004. The implementation of MISO's energy market is subject to successful completion of market test runs and approval of certain compliance filings. On January 27, 2005, MISO announced that financially binding market activities would be postponed until April 1, 2005 to permit additional testing of systems and training. FirstEnergy affiliates have been certified as market participants and will participate in the MISO markets when they begin operation.

Capital Requirements

Capital expenditures for the Companies, FES and FirstEnergy's other subsidiaries for the years 2005 through 2007 excluding nuclear fuel, are shown in the following table. Such costs include expenditures for the betterment of existing facilities and for the construction of generating capacity, facilities for environmental compliance, transmission lines, distribution lines, substations and other assets.

	2004 Actual	Capital Expenditures Forecast 2005	2006-2007	Total
		(In millions)		
OE	$ 112	$ 133	$ 307	$ 440
Penn	76	82	145	227
CEI	93	103	265	368
TE	51	56	136	192
JCP&L	153	178	333	511
Met-Ed	53	67	138	205
Penelec	53	89	183	272
ATSI	22	74	225	299
FES	92	163	542	705
Other subsidiaries	26	34	69	103
Total	$ 731	$ 979	$ 2,343	$ 3,322

During the 2005-2007 period, maturities of, and sinking fund requirements for, long-term debt and preferred stock of FirstEnergy and its subsidiaries are:

	Preferred Stock and Long-Term Debt Redemption Schedule 2005	2006-2007	Total
		(In millions)	
OE	$ 134	$ 9	$ 143
Penn	2	14	16
CEI*	1	122	123
TE	0	30	30
JCP&L	17	226	243
Met-Ed	30	151	181
Penelec	8	3	11
FirstEnergy	300	1,215	1,515
Other subsidiaries	5	23	28
Total	$ 497	$ 1,793	$ 2,290

* CEI has an additional $21 million due to associated companies in 2006-2007.

The Companies' and FES's respective investments for additional nuclear fuel, and nuclear fuel investment reductions as the fuel is consumed, during the 2005-2007 period are presented in the following table. The table also displays the Companies' operating lease commitments, net of capital trust cash receipts for the 2005-2007 period.

	Nuclear Fuel Forecasts: New Investments 2005	2006-2007	Total	Consumption 2005	2006-2007	Total	Net Operating Lease Commitments 2005	2006-2007	Total
					(In millions)				
OE	$ 21	$ 54	$ 75	$ 24	$ 49	$ 73	$ 82	$ 160	$ 242
Penn	13	50	63	17	35	52	--	--	--
CEI	11	65	76	28	63	91	18	25	43
TE	8	46	54	20	44	64	80	158	238
JCP&L	--	--	--	--	--	--	2	3	5
Met-Ed	--	--	--	--	--	--	1	3	4
Total	$ 53	$ 215	$ 268	$ 89	$ 191	$ 280	$ 183	$ 349	$ 532

Short-term borrowings outstanding as of December 31, 2004, consisted of $29 million of bank borrowings (OE - $25 million and HVACs - $4 million), and $142 million of OES Capital, Incorporated. OES Capital is a wholly owned subsidiary of OE whose borrowings are secured by customer accounts receivable purchased from OE. OES Capital can borrow up to $170 million under a receivables financing agreement at rates based on certain bank commercial paper. FirstEnergy and OE had $1.4 billion available under $1.75 billion of revolving lines of credit as of December 31, 2004. FirstEnergy may borrow under these facilities and could transfer any of its borrowings to its subsidiaries. These revolving credit facilities, combined with an aggregate $550 million of accounts receivable financing facilities for OE, CEI, TE, Met-Ed, Penelec and Penn, are intended to provide liquidity to meet our short-term working capital requirements and those of our subsidiaries. Total unused borrowing capability under existing facilities and accounts receivable financing facilities totaled $1.7 billion as of December 31, 2004. An additional source of ongoing cash for FirstEnergy, as a holding company, is cash dividends from its subsidiaries. In 2004, the holding company received $782 million of cash dividends on common stock from its subsidiaries.

Based on their present plans, the Companies could provide for their cash requirements in 2005 from the following sources: funds to be received from operations; available cash and temporary cash investments as of December 31, 2004 (Company's nonutility subsidiaries - $51 million, and OE - $1 million); the issuance of long-term debt (for refunding purposes); and funds available under revolving credit arrangements.

The extent and type of future financings will depend on the need for external funds as well as market conditions, the maintenance of an appropriate capital structure and the ability of the Companies to comply with coverage requirements in order to issue FMB and preferred stock. The Companies will continue to monitor financial market conditions and, where appropriate, may take advantage of economic opportunities to refund debt and preferred stock to the extent that their financial resources permit.

The coverage requirements contained in the first mortgage indentures under which the Companies issue FMB provide that, except for certain refunding purposes, the Companies may not issue FMB unless applicable net earnings (before income taxes), calculated as provided in the indentures, for any period of twelve consecutive months within the fifteen calendar months preceding the month in which such additional bonds are issued, are at least twice annual interest requirements on outstanding FMB, including those being issued. At the end of 2004, the Ohio Companies and Penn had the aggregate capability to issue approximately $4.4 billion of additional FMB on the basis of property additions and retired bonds under the terms of their respective mortgage indentures. The issuance of FMB by OE and CEI are also subject to provisions of their senior note indentures generally limiting the incurrence of additional secured debt, subject to certain exceptions that would permit, among other things, the issuance of secured debt (including FMB) (i) supporting pollution control notes or similar obligations, or (ii) as an extension, renewal or replacement of previously outstanding secured debt. In addition, these provisions would permit OE and CEI to incur additional secured debt not otherwise permitted by a specified exception of up to $641 million and $588 million, respectively, as of December 31, 2004. Under the provisions of its senior note indenture, JCP&L may issue additional FMB only as collateral for senior notes. As of December 31, 2004, JCP&L had the capability to issue $644 million of additional senior notes upon the basis of FMB collateral.

OE's, Penn's, TE's and JCP&L's respective articles of incorporation prohibit the sale of preferred stock unless applicable gross income, calculated as provided in the articles of incorporation, is equal to at least 1-1/2 times the aggregate of the annual interest requirements on indebtedness and annual dividend requirements on preferred stock outstanding immediately thereafter. Based upon applicable earnings coverage tests in their respective charters, OE, Penn, TE and JCP&L could issue a total of $4.5 billion of preferred stock (assuming no additional debt was issued) as of the end of 2004. CEI, Met-Ed and Penelec have no restrictions on the issuance of preferred stock.

To the extent that coverage requirements or market conditions restrict the Companies' abilities to issue desired amounts of FMB or preferred stock, the Companies may seek other methods of financing. Such financings could include the sale of preferred and/or preference stock or of such other types of securities as might be authorized by applicable regulatory authorities which would not otherwise be sold and could result in annual interest charges and/or dividend requirements in excess of those that would otherwise be incurred.

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

Nuclear Regulation

The construction, operation and decommissioning of nuclear generating units are subject to the regulatory jurisdiction of the NRC including the issuance by it of construction permits, operating licenses, and possession only licenses for decommissioning reactors. The NRC's procedures with respect to the amendment of nuclear reactor operating licenses afford opportunities for interested parties to request adjudicatory hearings on health, safety and environmental issues subject to meeting NRC "standing" requirements. The NRC may require substantial changes in operation or the installation of additional equipment to meet safety or environmental standards, subject to the backfit rule requiring the NRC to justify such new requirements as necessary for the overall protection of public health and safety. The possibility also exists for modification, denial or revocation of licenses. As a result of the merger with GPU, FirstEnergy now owns the TMI-2 and the Saxton Nuclear Experimental Facility. Both facilities are in various stages of decommissioning. TMI-2 is in a post-defueling monitored storage condition, with decommissioning planned in 2014, absent an extension of the operating license to the owner of TMI-1. Saxton is in the final stages of decommissioning, with license termination and final site restoration scheduled for the third quarter of 2005. Beaver Valley Unit 1 was placed in commercial operation in 1976, and its operating license expires in 2016. Davis-Besse was placed in commercial operation in 1977, and its operating license expires in 2017. Perry Unit 1 and Beaver Valley Unit 2 were placed in commercial operation in 1987, and their operating licenses expire in 2026 and 2027, respectively. FirstEnergy submitted a license renewal application with the NRC seeking to extend the operation of Beaver Valley Units 1 and 2 to 2036 and 2047, respectively.

Davis-Besse, which is operated by FENOC, began its scheduled refueling outage on February 16, 2002. The plant was originally scheduled to return to service by the end of March 2002. During the refueling outage, FENOC found corrosion in the reactor vessel head near some of the control rod drive mechanism penetration nozzles, created by boric acid deposits from leaks in the nozzles. As a result, the NRC issued a confirmatory action letter stating that restart of the plant would be subject to prior NRC approval, and it established an Inspection Manual Chapter 0350 Oversight Panel to ensure close NRC oversight of Davis-Besse's corrective actions.

On March 8, 2004, FENOC received NRC authorization to restart Davis-Besse and the plant achieved full power on April 4, 2004.

The NRC granted restart authorization in an order containing several commitments for Davis-Besse. Those requirements include ongoing independent assessments of the site's operational performance, safety culture and safety conscious work environment, and corrective action and engineering programs for five years, as well as visual inspection of the reactor head and lower vessel during the plant's mid-cycle outage, which took place in late January and early February of 2005.

In 2002, FENOC spent approximately $115 million in additional nuclear-related operation and maintenance costs, approximately $120 million in replacement power costs and approximately $63 million in capital expenditures related to the reactor head and restart. In 2003, FENOC spent approximately $93 million in additional nuclear-related operation and maintenance costs, approximately $196 million in replacement power costs and approximately $21 million in capital expenditures related to the reactor head and restart. In 2004, FENOC spent approximately $900,000 in additional nuclear-related operation and maintenance costs and approximately $64 million in replacement power costs during the remaining period of the outage.

The NRC has promulgated and continues to promulgate orders and regulations related to the safe operation of nuclear power plants and standards for decommissioning clean-up and final license termination. The Companies cannot predict what additional orders and regulations (including post-September 11, 2001 security enhancements) may be promulgated, design changes required or the effect that any such regulations or design changes or additional clean-up standards for final site release, or the consideration thereof, may have upon their nuclear plants. Although the Companies have no reason to anticipate an accident at any of their nuclear plants, if such an accident did happen, it could have a material but currently undeterminable adverse effect on FirstEnergy's consolidated financial position. In addition, such an accident at any operating nuclear plant, whether or not owned by the Companies, could result in regulations or requirements that could affect the operation, licensing, or decommissioning of plants that the Companies do own with a consequent but currently undeterminable adverse impact, and could affect the Companies' abilities to raise funds in the capital markets.

Nuclear Insurance

The Price-Anderson Act limits the public liability which can be assessed with respect to a nuclear power plant to $10.8 billion (assuming 104 units licensed to operate) for a single nuclear incident, which amount is covered by: (i) private insurance amounting to $300 million; and (ii) $10.5 billion provided by an industry retrospective rating plan required by the NRC pursuant thereto. Under such retrospective rating plan, in the event of a nuclear incident at any unit in the United States resulting in losses in excess of private insurance, up to $100.6 million (but not more than $10 million per unit per year in the event of more than one incident) must be contributed for each nuclear unit licensed to operate in the country by the licensees thereof to cover liabilities arising out of the incident. Based on their present nuclear ownership and leasehold interests, the Companies' maximum potential assessment under these provisions would be $402.4 million (OE-$107.5 million, Penn-$84.5 million, CEI-$121.4 million and TE-$89.0 million) per incident but not more than $40.0 million (OE-$10.7 million, Penn-$8.4 million, CEI-$12.1 million and TE-$8.8 million) in any one year for each incident.

In addition to the public liability insurance provided pursuant to the Price-Anderson Act, the Companies have also obtained insurance coverage in limited amounts for economic loss and property damage arising out of nuclear incidents. The Companies are members of NEIL which provides coverage (NEIL I) for the extra expense of replacement power incurred due to prolonged accidental outages of nuclear units. Under NEIL I, the Companies have policies, renewable yearly, corresponding to their respective nuclear interests, which provide an aggregate indemnity of up to approximately $1.488 billion (OE-$397.2 million, Penn-$280.1 million, CEI-$478.9 million and TE-$332.1 million) for replacement power costs incurred during an outage after an initial 20-week waiting period. Members of NEIL I pay annual premiums and are subject to assessments if losses exceed the accumulated funds available to the insurer. The Companies' present maximum aggregate assessment for incidents at any covered nuclear facility occurring during a policy year would be approximately $10.4 million (OE-$2.8 million, Penn-$2.0 million, CEI-$3.3 million and TE-$2.3 million).

The Companies are insured as to their respective nuclear interests under property damage insurance provided by NEIL to the operating company for each plant. Under these arrangements, $2.75 billion of coverage for decontamination costs, decommissioning costs, debris removal and repair and/or replacement of property is provided. The Companies pay annual premiums for this coverage and are liable for retrospective assessments of up to approximately $57.1 million (OE-$16.0 million, Penn-$11.2 million, CEI-$17.5 million, TE-$11.6 million, JCP&L-$0.2 million, Met-Ed-$0.4 million and Penelec-$0.2 million) during a policy year. On September 30, 2003, CEI and TE tendered Proofs of Loss under the Nuclear Electric Insurance Limited (NEIL) Property Damage and Accidental Outage Policies for the Davis-Besse Nuclear Power Station related to an outage that began in 2002 at that station. The property damage losses claimed by CEI and TE total $77.9 million and the Accidental Outage losses claimed by CEI and TE total $106.7 million. On December 18, 2004, NEIL denied CEI's and TE's claims. CEI and TE are considering their options with respect to pursuing an arbitration of this matter.

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

The NRC requires nuclear power plant licensees to obtain minimum property insurance coverage of $1.06 billion or the amount generally available from private sources, whichever is less. The proceeds of this insurance are required to be used first to ensure that the licensed reactor is in a safe and stable condition and can be maintained in that condition so as to prevent any significant risk to the public health and safety. Within 30 days of stabilization, the licensee is required to prepare and submit to the NRC a cleanup plan for approval. The plan is required to identify all cleanup operations necessary to decontaminate the reactor sufficiently to permit the resumption of operations or to commence decommissioning. Any property insurance proceeds not already expended to place the reactor in a safe and stable condition must be used first to complete those decontamination operations that are ordered by the NRC. The Companies are unable to predict what effect these requirements may have on the availability of insurance proceeds to the Companies for the Companies' bondholders.

Environmental Matters

Various federal, state and local authorities regulate the Companies with regard to air and water quality and other environmental matters. The effects of compliance on the Companies with regard to environmental matters could have a material adverse effect on FirstEnergy's earnings and competitive position. These environmental regulations affect FirstEnergy's earnings and competitive position to the extent that it competes with companies that are not subject to such regulations and therefore do not bear the risk of costs associated with compliance, or failure to comply, with such regulations. Overall, FirstEnergy believes it is in compliance with existing regulations but is unable to predict future change in regulatory policies and what, if any, the effects of such change would be. FirstEnergy estimates additional capital expenditures for environmental compliance of approximately \$430 million for 2005 through 2007, which is included in the \$3.3 billion of forecasted capital expenditures for 2005 through 2007.

Clean Air Act Compliance

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

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

National Ambient Air Quality Standards

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

Mercury Emissions

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

W. H. Sammis Plant

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

Regulation of Hazardous Waste

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

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

Climate Change

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

The Companies cannot currently estimate the financial impact of climate change policies, although the potential restrictions on CO_2 emissions could require significant capital and other expenditures. However, the CO_2 emissions per kilowatt-hour of electricity generated by the Companies is lower than many regional competitors due to the Companies' diversified generation sources which 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 the Companies' plants. In addition, Ohio, New Jersey and Pennsylvania have water quality standards applicable to the Companies' operations. As provided in the Clean Water Act, authority to grant federal National Pollutant Discharge Elimination System water discharge permits can be assumed by a state. Ohio, New Jersey and Pennsylvania have assumed such authority.

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

Fuel Supply

FirstEnergy currently has long-term coal contracts to provide approximately 18.4 million tons for the year 2005. The contracts are shared among the Companies based on various economic considerations. This contract coal is produced primarily from mines located in Pennsylvania, Kentucky, Wyoming and West Virginia. The contracts expire at various times through December 31, 2021.

The Companies estimate their 2005 coal requirements to be approximately 22.4 million tons (OE – 6.7 million, Penn – 7.7 million, CEI – 6.0 million, and TE – 2.0 million) to be met from the long-term contracts discussed above and spot market purchases. See "Environmental Matters" for factors pertaining to meeting environmental regulations affecting coal-fired generating units.

CEI, TE, OE and Penn have contracts for uranium material and conversion services through 2008. The enrichment services are contracted for all of the enrichment requirements for nuclear fuel through 2006. A portion of enrichment requirements is also contracted through 2011. Fabrication services for fuel assemblies are contracted for the next two reloads for Beaver Valley Unit 1, the next two reloads for Beaver Valley Unit 2 (through approximately 2007 and 2006, respectively), the next reload for Davis-Besse (through approximately 2006) and through the operating license period for Perry (through approximately 2026). The Davis-Besse fabrication contract also has an extension provision for services through the current operating license period (about 2017). In addition to the existing commitments, the Companies intend to make additional arrangements for the supply of uranium and for the subsequent conversion, enrichment, fabrication, and waste disposal services.

On-site spent fuel storage facilities are expected to be adequate for Perry through 2011; facilities at Beaver Valley Units 1 and 2 are expected to be adequate through 2015 and 2008, respectively. With the plant modifications completed in 2002, Davis-Besse has adequate storage through the remainder of its current operating license period. After current on-site storage capacity is exhausted, additional storage capacity will have to be obtained either through plant modifications, interim off-site disposal, or permanent waste disposal facilities. The Federal Nuclear Waste Policy Act of 1982 provides for the construction of facilities for the permanent disposal of high-level nuclear wastes, including spent fuel from nuclear power plants operated by electric utilities. CEI, TE, OE and Penn have contracts with the U.S. Department of Energy (DOE) for the disposal of spent fuel for Beaver Valley, Davis-Besse and Perry. On February 15, 2002, President Bush approved the DOE's recommendation of Yucca Mountain for underground disposal of spent nuclear fuel from nuclear power plants and high level waste from U.S. defense programs. The approval by President Bush enables the process to proceed to the licensing phase. Based on the DOE schedule published in the July 1999 Draft Environmental Impact Statement, the Yucca Mountain Repository is currently projected to start receiving spent fuel in 2010. The Repository is expected to be delayed further as the result of an announced delay in submission of the license application. The Companies intend to make additional arrangements for storage capacity as a contingency for further delays with the DOE acceptance of spent fuel for disposal past 2010.

System Capacity and Reserves

The 2004 net maximum hourly demand for each of the Companies was: OE-5,461 MW (including an additional 273 MW of firm power sales under a contract which extends through 2005) on June 9, 2004; Penn-987 MW (including an additional 56 MW of firm power sales under a contract which extends through 2005) on June 15, 2004; CEI-4,126 MW on August 27, 2004; TE-2,032 MW on August 3, 2004; JCP&L-5,457 MW on August 20, 2004; Met-Ed-2,548 MW on August 3, 2004; and Penelec-2,830 MW on December 20, 2004. JCP&L's load was auctioned off in the New Jersey BGS Auction, transferring the full 5,100 MW load obligation to other parties for the supply period beginning June 1, 2005. FES participated in the auction and won a segment of that load.

Based on existing capacity plans, ongoing arrangements for firm purchase contracts, and anticipated term power sales and purchases, FirstEnergy has sufficient supply resources to meet load obligations. The current FirstEnergy capacity portfolio contains 13,387 MW of owned generation and approximately 1,600 MW of long-term purchases from NUGs. Any remaining load obligations will be met through a mix of multi-year forward purchases, short-term forward purchases (less than one year) and spot market purchases.

The Companies' sources of generation during 2004 were:

	Coal	Nuclear
OE	72.5%	27.5%
Penn	39.8%	60.2%
CEI	58.7%	41.3%
TE	48.1%	51.9%
Total FirstEnergy	60.2%	39.8%

Regional Reliability

The Ohio Companies and Penn participate with 24 other electric companies operating in nine states in ECAR, which was organized for the purpose of furthering the reliability of bulk power supply in the area through coordination of the planning and operation by the ECAR members of their bulk power supply facilities. The ECAR members have established principles and procedures regarding matters affecting the reliability of the bulk power supply within the ECAR region. Procedures have been adopted regarding: i) the evaluation and simulated testing of systems' performance; ii) the establishment of minimum levels of daily operating reserves; iii) the development of a program regarding emergency procedures during conditions of declining system frequency; and iv) the basis for uniform rating of generating equipment.

The transmission facilities of JCP&L, Met-Ed and Penelec are operated by PJM. PJM is the organization responsible for the operation and control of the bulk electric power system throughout major portions of five Mid-Atlantic states and the District of Columbia. PJM is dedicated to meeting the reliability criteria and standards of NERC and the Mid-Atlantic Area Council.

Competition

The Companies compete with other utilities for intersystem bulk power sales and for sales to municipalities and cooperatives. The Companies also compete with suppliers of natural gas and other forms of energy in connection with their industrial and commercial sales and in the home climate control market, both with respect to new customers and conversions, and with all other suppliers of electricity. To date, there has been no substantial cogeneration by the Companies' customers.

As a result of actions taken by state legislative bodies over the last few years, major changes in the electric utility business are occurring in parts of the United States, including Ohio, New Jersey and Pennsylvania where FirstEnergy's utility subsidiaries operate. These changes have resulted in fundamental alterations in the way traditional integrated utilities and holding company systems, like FirstEnergy, conduct their business. In accordance with the Ohio electric utility restructuring law under which Ohio electric customers could begin choosing their electric generation suppliers starting in January 2001, FirstEnergy has further aligned its business units to accommodate its retail strategy and participate in the competitive electricity marketplace in Ohio. The organizational changes deal with the unbundling of electric utility services and new ways of conducting business. FirstEnergy's competitive segment participates in deregulated energy markets in Ohio, Pennsylvania, New Jersey and Michigan.

Competition in Ohio's electric generation began on January 1, 2001. FirstEnergy moved the operation of the generation portion of its business to its competitive business unit as reflected in its approved Ohio transition plan. The Companies continue to provide generation services to regulated franchise customers who have not chosen an alternative, competitive generation supplier, except in New Jersey where JCP&L's obligation to provide BGS has been removed through a transitional mechanism of auctioning the obligation (see "NJBPU Rate Matters"). In September 2002, Met-Ed and Penelec assigned their PLR responsibility to FES through a wholesale power sale agreement. Under the terms of the wholesale agreement, FES assumed the supply obligation and the supply profit and loss risk, for the portion of power supply requirements not self-supplied by Met-Ed and Penelec. The agreement will be automatically extended on an annual basis unless any party elects to cancel the agreement by November 1 of the preceding year (see "PPUC Rate Matters" for further discussion). The Ohio Companies and Penn obtain their generation through power supply agreements with FES.

Research and Development

The Companies participate in funding the Electric Power Research Institute (EPRI), which was formed for the purpose of expanding electric research and development under the voluntary sponsorship of the nation's electric utility industry - public, private and cooperative. Its goal is to mutually benefit utilities and their customers by promoting the development of new and improved technologies to help the utility industry meet present and future electric energy needs in environmentally and economically acceptable ways. EPRI conducts research on all aspects of electric power production and use, including fuels, generation, delivery, energy management and conservation, environmental effects and energy analysis. The major portion of EPRI research and development projects is directed toward practical solutions and their applications to problems currently facing the electric utility industry.

Executive Officers

The executive officers are elected at the annual organization meeting of the Board of Directors, held immediately after the annual meeting of stockholders, and hold office until the next such organization meeting, unless the Board of Directors shall otherwise determine, or unless a resignation is submitted.

Name	Age	Position Held During Past Five Years	Dates
A. J. Alexander	53	President and Chief Executive Officer	2004-present
		President and Chief Operating Officer	2001-2004
		President	2000-2001
		Executive Vice President and General Counsel	*-2000
L. M. Cavalier	53	Vice President – Human Resources	2001-present
		President – Eastern Region	*-2001
M. T. Clark	54	Senior Vice President	2004-present
		Vice President – Business Development	2000-2004
		Managing Director – Business Development	*-2000
D. S. Elliott	50	Senior Vice President	2001-present
		Vice President	*-2001
R. R. Grigg	56	Executive Vice President and Chief Operating Officer	2004-present
		President and Chief Executive Officer – WE Generation	*-2004
C. E. Jones	49	Senior Vice President	2003-present
		Vice President – Regional Operations	2001-2003
		President – Northern Region	*-2001
K. J. Keough	45	Senior Vice President	2001-present
		Vice President – Business Planning & Ventures	*-2001
G. R. Leidich	54	President and Chief Nuclear Officer – FENOC	2003-present
		Executive Vice President – FENOC	2002-2003
		Executive Vice President – Institute of Nuclear Power Operations	*-2002
R. H. Marsh	54	Senior Vice President and Chief Financial Officer	2001-present
		Vice President and Chief Financial Officer	*-2001
S. E. Morgan	54	President – JCP&L	2003-present
		Vice President – Energy Delivery	2002-2003
		President – Central Region	*-2002
G. L. Pipitone	54	President - FES	2004-present
		Senior Vice President	2001-2004
		Vice President	*-2001
D. R. Schneider	43	Vice President – Commodity Operations	2004-present
		Vice President – Fossil Operations	2001-2004
		Plant Manager	*-2001
C. B. Snyder	59	Senior Vice President	2001-present
		Executive Vice President - Corporate Affairs - GPU	*-2001
L. L. Vespoli	45	Senior Vice President and General Counsel	2001-present
		Vice President and General Counsel	2000-2001
		Associate General Counsel	*-2000
H. L. Wagner	52	Vice President, Controller and Chief Accounting Officer	2001-present
		Controller and Chief Accounting Officer	*-2001
T. M. Welsh	55	Senior Vice President	2004-present
		Vice President – Communications	2001-2004
		Manager – Communications Services	*-2001

Mrs. Vespoli and Messrs. Alexander, Marsh and Wagner are the executive officers, as noted above, of OE, Penn, CEI, TE, Met-Ed and Penelec. Mrs. Vespoli and Messrs. Marsh, Morgan and Wagner are the executive officers of JCP&L.

* Indicates position held at least since January 1, 2000.

Employees

As of January 1, 2005, FirstEnergy's nonutility subsidiaries and the Companies had a total of 15,245 employees located in the United States as follows:

FESC	2,712
OE	1,170
CEI	905
TE	414
Penn	200
JCP&L	1,444
Met-Ed	651
Penelec	843
ATSI	33
FES	2,001
FENOC	2,756
FSG	2,023
First Communications	93
Total	15,245

Approximately 7,218 of the above employees (including 720 for OE, 635 for CEI, 317 for TE, 153 for Penn, 1,155 for JCP&L, 490 for Met-Ed and 605 for Penelec) are covered by collective bargaining agreements.

On December 8, 2004, employees represented by IBEW System Council U-3 began a strike against JCP&L. JCP&L continues to utilize management, other non-union personnel from around FirstEnergy's system and contractors to perform service reliability and priority maintenance work while the union members are on strike. The labor agreement between JCP&L and System Council U-3 originally expired on October 31, 2003 but was extended several times and ultimately expired on December 7, 2004. JCP&L and the leadership of System Council U-3 continue to negotiate in an attempt to reach a new agreement and end the work stoppage. It is unknown when such an agreement will be reached or when the work stoppage will end. On January 31, 2005, IBEW Local 245, ratified a three-year contract agreement with TE, FENOC, and FGCO. On February 4, 2005, IBEW Local 272, representing approximately 350 employees of the Bruce Mansfield Plant, ratified a three-year contract with FGCO.

FirstEnergy Website

Each of the registrant's annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and amendments to those reports filed with or furnished to the SEC pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 are also made available free of charge on or through FirstEnergy's internet website at www.firstenergycorp.com. These reports are posted on the website as soon as reasonably practicable after they are electronically filed with the SEC.

ITEM 2. PROPERTIES

The Companies' respective first mortgage indentures constitute, in the opinion of the Companies' counsel, direct first liens on substantially all of the respective Companies' physical property, subject only to excepted encumbrances, as defined in the indentures. See "Leases" and "Capitalization" notes to the respective financial statements for information concerning leases and financing encumbrances affecting certain of the Companies' properties.

The Companies own, individually or together as tenants in common, and/or lease, the generating units in service as of March 1, 2005, shown on the table below.

Plant-Location	Unit	NDC (MW) Total	OE %	OE MW	Penn %	Penn MW	CEI %	CEI MW	TE %	TE MW	JCP&L %	JCP&L MW	Met-Ed %	Met-Ed MW	FES %	FES MW
Coal-Fired Units																
Ashtabula-																
Ashtabula, OH	5	244	–	–	–	–	100.00%	244	–	–	–	–	–	–	–	–
Bay Shore-																
Toledo, OH	1-4	631	–	–	–	–	–	–	100.00%	631	–	–	–	–	–	–
R. E. Burger-																
Shadyside, OH	3-5	406	100.00%	406	–	–	–	–	–	–	–	–	–	–	–	–
Eastlake-Eastlake, OH	1-5	1,233	–	–	–	–	100.00%	1,233		–	–	–	–	–	–	–
Lakeshore-																
Cleveland, OH	18	245	–	–	–	–	100.00%	245	–	–	–	–	–	–	–	–
Bruce Mansfield-	1	780	60.00%	468	33.50%	261	6.50%	51	–	–	–	–	–	–	–	–
Shippingport, PA	2	780	43.06%	336	9.36%	73	30.28% (a)	236	17.30% (a)	135	–	–	–	–	–	–
	3	800	49.34%	395	6.28%	50	24.47%	196	19.91%	159	–	–	–	–	–	–
W. H. Sammis-	1-6	1,620	100.00%	1,620	–	–	–	–	–	–	–	–	–	–	–	–
Stratton, OH	7	600	48.00%	288	20.80%	125	31.20%	187	–	–	–	–	–	–	–	–
Total		7,339	–	3,513	–	509	–	2,392	–	925	–	–	–	–	–	–
Nuclear Units																
Beaver Valley-	1	821	35.00%	287	65.00%	534	–	–	–	–	–	–	–	–	–	–
Shippingport, PA	2	831	41.88% (b)	348	13.74%	114	24.47%	203	19.91%	166	–	–	–	–	–	–
Davis-Besse-																
Oak Harbor, OH	1	883	–	–	–	–	51.38%	454	48.62%	429	–	–	–	–	–	–
Perry-																
N. Perry Village, OH	1	1,260	30.00% (b)	378	5.24%	66	44.85%	565	19.91% (c)	251	–	–	–	–	–	–
Total		3,795		1,013		714		1,222		846		–		–		–
Oil/Gas-Fired/ Pumped Storage Units																
Richland-Defiance, OH	1-3	42	–	–	–	–	–	–	100.00%	42	–	–	–	–	–	–
	4-6	390	–	–	–	–	–	–	–	–	–	–	–	–	100.00%	390
Seneca-Warren, PA	1-3	435	–	–	–	–	100.00%	435	–	–	–	–	–	–	–	–
Sumpter-Sumpter Twp, MI	1-4	340	–	–	–	–	–	–	–	–	–	–	–	–	100.00%	340
West Lorain	1-1	120	100.00%	120	–	–	–	–	–	–	–	–	–	–	–	–
Lorain, OH	2-6	425	–	–	–	–	–	–	–	–	–	–	–	–	100.00%	425
Yard's Creek-Blairstown																
Twp., NJ	1-3	200	–	–	–	–	–	–	–	–	50%	200	–	–	–	–
Other		301		109		19		33		35		86		19		–
Total		2,253		229		19		468		77		286		19		1,155
Total		13,387		4,755		1,242		4,082		1,848		286		19		1,155

Notes: (a) CEI's interests consist of 1.68% owned and 28.60% leased and TE's interests are leased.

(b) OE's interests consist of 20.22% owned and 21.66% leased for Beaver Valley Unit 2; and 17.42% owned (representing portion leased from a wholly owned subsidiary of OE) and 12.58% leased for Perry.

(c) TE's interests consist of 1.65% owned and 18.26% leased.

Prolonged outages of existing generating units might make it necessary for the Companies, depending upon the demand for electric service upon their system, to use to a greater extent than otherwise, less efficient and less economic generating units, or purchased power, and in some cases may require the reduction of load during peak periods under the Companies' interruptible programs, all to an extent not presently determinable.

The Companies' generating plants and load centers are connected by a transmission system consisting of elements having various voltage ratings ranging from 23 kV to 500 kV. The Companies' overhead and underground transmission lines aggregate 14,978 pole miles.

The Companies' electric distribution systems include 114,177 miles of overhead pole line and underground conduit carrying primary, secondary and street lighting circuits. They own substations with a total installed transformer capacity of 91,117,000 kilovolt-amperes.

The transmission facilities that are owned and operated by ATSI also interconnect with those of AEP, DPL, Duquesne, Allegheny, MEC and Penelec. The transmission facilities of JCP&L, Met-Ed and Penelec are physically interconnected and are operated on an integrated basis as part of the PJM RTO.

FirstEnergy's distribution and transmission systems as of December 31, 2004, consist of the following:

	Substation Distribution Lines	Transmission Lines	Transformer Capacity
	(Miles)		*(kV-amperes)*
OE	29,402	550	8,318,000
Penn	5,636	44	1,750,000
CEI	24,860	2,144	9,300,000
TE	1,622	223	3,691,000
JCP&L	18,493	2,106	21,154,000
Met-Ed	14,424	1,407	9,985,000
Penelec	19,740	2,690	14,238,000
ATSI*	--	5,814	22,681,000
Total	114,177	14,978	91,117,000

* Represents transmission lines of 69kv and above in service areas of OE, Penn, CEI and TE.

ITEM 3. LEGAL PROCEEDINGS

Reference is made to Note 13, Commitments, Guarantees and Contingencies, of the Notes to Consolidated Financial Statements contained in Item 8 for a description of certain legal proceedings involving FirstEnergy, OE, CEI, TE, Penn, JCP&L, Met-Ed and Penelec.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

None.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

The information required by Item 5. regarding FirstEnergy's market information, including stock exchange listings and quarterly stock market prices, dividends and holders of common stock is included on page 5 of FirstEnergy's 2004 Annual Report to Stockholders (Exhibit 13). The information required for OE, CEI, TE, Penn, JCP&L, Met-Ed and Penelec is not applicable because they are wholly owned subsidiaries.

The table below includes information on a monthly basis for the fourth quarter, regarding purchases made by FirstEnergy of its common stock.

Period	Total Number Of Shares Purchased [(a)]	Average Price Paid per Share	Total Number of Shares Purchased As Part of Publicly Announced Plans Or Programs [(b)]	Maximum Number (or Approximate Dollar Value) of Shares that May Yet Be Purchased Under the Plans Or Programs
October 1-31, 2004	175,290	$41.13	--	--
November 1-30, 2004	379,505	$42.68	--	--
December 1-31, 2004	306,911	$39.96	--	--
Fourth Quarter	861,706	$41.40	--	--

(a) Share amounts reflect purchases on the open market to satisfy FirstEnergy's obligations to deliver common stock under its Executive and Director Incentive Compensation Plan, Deferred Compensation Plan for Outside Directors, Executive Deferred Compensation Plan, Savings Plan and Stock Investment Plan. In addition, such amounts reflect shares tendered by employees to pay the exercise price or withholding taxes upon exercise of stock options granted under the Executive and Director Incentive Compensation Plan.

(b) FirstEnergy does not currently have any publicly announced plan or program for share purchases.

ITEM 6. SELECTED FINANCIAL DATA

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

The information required for items 6 through 8 is incorporated herein by reference to Selected Financial Data, Management's Discussion and Analysis of Results of Operations and Financial Condition, and Financial Statements included on the pages shown in the following table in the respective company's 2004 Annual Report to Stockholders (Exhibit 13).

	Item 6	Item 7	Item 7A	Item 8
FirstEnergy	3	4-38	26-28	39-85
OE	3	4-16	10	17-44
Penn	3	4-13	8-9	14-35
CEI	3	4-15	9	16-41
TE	3	4-16	9-10	17-43
JCP&L	3	4-13	8-10	14-35
Met-Ed	3	4-13	8-10	14-36
Penelec	3	4-12	8-9	13-34

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

Each registrant's Chief Executive Officer and Chief Financial Officer have reviewed and evaluated such registrant's disclosure controls and procedures, as defined in the Securities Exchange Act of 1934 Rules 13a-15(e) and 15d-15(e), as of the end date covered by this report. Based upon this evaluation, the respective Chief Executive Officer and Chief Financial Officer concluded that such registrant's disclosure controls and procedures are effective.

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 registrants' internal control over financial reporting under the supervision of each registrant's chief executive officer and chief financial officer. Based on that evaluation, management concluded that the registrants' internal control over financial reporting was effective as of December 31, 2004. Management's assessment of the effectiveness of the registrants' internal control over financial reporting, as of December 31, 2004, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their reports included in each registrant's 2004 Annual Report to Stockholders and incorporated by reference hereto.

Changes in Internal Controls over Financial Reporting

There were no changes in the registrants' internal controls over financial reporting during the fourth quarter of 2004 that have materially affected, or are reasonably likely to materially affect, the registrants' internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

Severance Agreements

On February 15, 2005, in response to a shareholder proposal at the 2004 Annual Meeting that received the affirmative vote of approximately 64 percent of the votes cast, the Board of Directors adopted a new policy with respect to severance agreements. The Board's policy requires that any future severance agreement offered to any FirstEnergy employee that would be triggered by a change in control of FirstEnergy limit the multiplier of base salary and target short-term incentive compensation to 2.99 times. The Board's policy also requires that such severance agreements only contain such other terms, conditions and provisions as may be recommended by the Compensation Committee and approved by the independent directors of the Board and, at the discretion of such independent directors, approved by the shareholders. The Board's policy also requires that the Compensation Committee retain an independent third-party consultant to periodically review the prevailing competitive practices concerning severance agreements triggered by a change in control and report on such review to the Board.

In accordance with this policy, the Compensation Committee authorized, and FirstEnergy entered into, separate severance agreements with Guy L. Pipitone, Mark T. Clark, Lynn M. Cavalier and Richard R. Grigg on March 7, 2005, effective immediately. Severance benefits are limited to 2.99 times base salary and target short-term incentive compensation for Ms. Cavalier and Messrs. Clark and Grigg. Severance benefits are limited to 2.0 times base salary and target short-term incentive compensation for Mr. Pipitone. In addition, the Compensation Committee recommended, and the Board approved, the following additional terms. With respect to the retirement benefits of Ms. Cavalier and Messrs. Clark and Grigg, (a) three years will be added to his or her age and service at termination, (b) pension benefits will be calculated with the enhanced age and service, and (c) benefits will be paid out no earlier than an adjusted age of 55. With regard to health care, he or she will receive health care benefits on the same terms as an active employee for three years. Lastly, with regard to life insurance, he or she will receive life insurance benefits on the same terms as an active employee for three years. Mr. Pipitone's agreement provides that, in regard to retirement plans, (a) two years will be added to his age and service at termination, (b) pension benefits will be calculated with the enhanced age and service, and (c) benefits will be paid out no earlier than an adjusted age of 55. In regard to health care, he will receive health care benefits on the same terms as an active employee for two years. Lastly, in regard to life insurance, he will receive life insurance benefits on the same terms as an active employee for two years.

Under the agreements, a change in control includes the acquisition of the beneficial ownership of 50 percent or more of the outstanding shares of common stock or other voting stock of FirstEnergy, a change in the majority of the members of the Board of Directors, or a reorganization, merger, or dissolution of FirstEnergy. The agreements are intended to ensure that the individuals are free from personal distractions in the context of a potential change in control, when the Board needs the objective assessment and advice of these executives to determine whether an offer is in the best interests of the Company and its shareholders. The principal severance benefits may be triggered when the individual is terminated or resigns for good reason, which generally is defined as a material change, following a change of control, inconsistent with the individual's previous job duties or compensation.

Under all of the above severance agreements, the executive would be prohibited for two years from working for or with competing entities after receiving severance benefits from this change in control agreement.

FirstEnergy also has in place separate severance agreements with Anthony J. Alexander, Richard H. Marsh, Carole B. Snyder, and Leila L. Vespoli, in the form applicable to Ms. Cavalier and Messrs. Clark and Grigg described above, except that such agreements provide for a benefit equal to 2.99 times the sum of the individual's base salary plus the average of his or her annual incentive compensation awards over the past three years. Additionally, in the case of Mr. Alexander, he is eligible for the specified severance benefits if he resigns, for any reason, during a 90-day period commencing 18 months following a change in control. Because the agreements for Mr. Marsh, Ms. Vespoli, and Ms. Snyder do not become effective until January 1, 2006, they remain covered under the severance agreements that were previously in place for each of them through December 31, 2005.

FirstEnergy also has in place separate severance agreements with Kevin J. Keough and Kathryn W. Dindo in the form applicable to Mr. Pipitone as described above, except that such agreements provide for a benefit equal to 2.00 times the sum of the individual's base salary plus the average of his or her annual incentive compensation awards over the past three years.

Executive Bonus Plan

FirstEnergy adopted an Executive Bonus Plan effective November 3, 2004. The plan was established for the purpose of providing for the purchase of personal life insurance for participants who are each deemed to be a member of a select group of highly compensated and/or management employees of FirstEnergy and its subsidiaries. The plan is part of an integrated executive compensation program that is intended to attract, retain and motivate certain key executives who are in a position to make significant contributions to the operation and profitability of FirstEnergy for the benefit of stockholders and customers. Employees of FirstEnergy and its subsidiaries who are or become subject to the provisions of Section 402 of the Sarbanes-Oxley Act of 2002, as amended, and are designated by the CEO or, in the case of the CEO, by the Compensation Committee of the Board, are eligible to participate in the Plan.

Policies under the plan will insure the participant's life and shall provide a death benefit equal to the participant's annual base salary as of a specified date.

A copy of the plan was filed as an exhibit to our Quarterly Report on Form 10-Q for the quarter ended September 30, 2004.

Executive and Director Incentive Compensation Plan Awards

On March 3, 2005, FirstEnergy notified the following executive officers that they were to receive the indicated performance-based restricted stock unit awards and restricted stock awards under the FirstEnergy Executive and Director Incentive Compensation Plan:

	Restricted Stock Units[1]	Restricted Stock Shares
A. J. Alexander	47,954	--
R. H. Marsh	5,131	--
L. L. Vespoli	5,644	25,000[2] 25,000[3]
M. T. Clark	4,950	50,000[2]
G. L. Pipitone	3,863	--
R. R. Grigg	16,901	--

(1) Period of Restriction expires upon the earlier of (i) March 1, 2008, (ii) recipient's death, (iii) recipient's termination from employment due to disability and (iv) a change in control occurs.

(2) Period of Restriction expires upon the earlier of (i) March 1, 2010, (ii) recipient's death, (iii) recipient's termination from employment due to disability and (iv) a change in control occurs.

(3) Period of Restriction expires upon the earlier of (i) March 1, 2015, (ii) recipient's death, (iii) recipient's termination from employment due to disability and (iv) a change in control occurs.

Each award become effective upon acknowledgement by the recipient. The Plan gives recipients the right to acquire stock after the Period of Restriction indicated above, and subject to forfeiture and other provisions under the Plan and the agreements between FirstEnergy and the recipient. The forms of the respective performance-based restricted stock unit and restricted stock agreements are filed as exhibits to this Annual Report on Form 10-K.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

FirstEnergy

The information required by Item 10, with respect to Identification of FirstEnergy's Directors and with respect to reports required to be filed under Section 16 of the Securities Exchange Act of 1934, is incorporated herein by reference to FirstEnergy's 2005 Proxy Statement filed with the SEC pursuant to Regulation 14A and, with respect to Identification of Executive Officers, to "Part I, Item 1. Business – Executive Officers" herein.

The Board of Directors has determined that Ernest J. Novak, Jr., an independent director, is the audit committee financial expert.

FirstEnergy makes available on its website at http://www.firstenergycorp.com/ir its Corporate Governance Policies and the charters for each of the following committees of the Board of Directors: Audit; Corporate Governance; Compensation; Finance; and Nuclear. The Corporate Governance Policies and Board committee charters are also available in print upon written request to David W. Whitehead, Corporate Secretary, FirstEnergy Corp., 76 South Main Street, Akron, OH 44308-1890.

FirstEnergy has adopted a Code of Business Conduct, which applies to all employees, including the Chief Executive Officer, the Chief Financial Officer and the Chief Accounting Officer. In addition, the Board of Directors has its own Code of Business Conduct. These Codes can be found on our website provided in the previous paragraph or upon written request to the Corporate Secretary.

Pursuant to Section 303A.12(a) of the New York Stock Exchange Listed Company Manual, the Company submitted the Annual CEO Certification to the NYSE on June 16, 2004.

OE, Penn, CEI, TE, JCP&L, Met-Ed and Penelec

A. J. Alexander, R. H. Marsh and R. R. Grigg are the Directors of OE, Penn, CEI, TE, Met-Ed and Penelec. Information concerning these individuals is shown in the "Executive Officers" section of Item 1. S. E. Morgan, C. E. Jones, L. L. Vespoli, B. S. Ewing, M. A. Julian, G. E. Persson and S. C. Van Ness are the Directors of JCP&L.

Mr. Ewing (Age 44) has served as FirstEnergy Service Company's Vice President – Energy Delivery since 2003. From 1999 to 2003, Mr. Ewing served as Director of Operations Services – Northern Region.

Mr. Julian (Age 48) has served as FirstEnergy Service Company's Vice President – Energy Delivery since 2003. From 2001 to 2003, Mr. Julian served as Director of Energy Delivery Technical Services. He was Director of Operations Services – Northern Region from 2000 to 2001 and Director of Operations Support Services – Central Region from 1999-2000.

Mrs. Persson (Age 74) has served in the New Jersey Division of Consumer Affairs Elder Fraud Investigation Unit since 1999. She previously served as liaison (Special Assistant Director) between the New Jersey Division of Consumer Affairs and various state boards. Prior to 1995, she was owner and President of Business Dynamics Associated of Red Bank, NJ. Mrs. Persson is a member of the United States Small Business Administration National Advisory Board, the New Jersey Small Business Advisory Council, the Board of Advisors of Brookdale Community College and the Board of Advisors of Georgian Court College.

Mr. Van Ness (Age 71) has been Of Counsel in the firm of Hubert, Van Ness, Cayci and Goodell, LP of Princeton, NJ since 1998. Prior to that he was affiliated with the law firm of Pico, Mack, Kennedy, Jaffe, Perrella and Yoskin of Trenton, NJ since 1990. He is also a director of The Prudential Insurance Company of America.

Information concerning the other Directors of JCP&L is shown in the "Executive Officers" section of Item 1.

Section 16(a) Beneficial Ownership Reporting Compliance – OE, Penn, CEI, TE, JCP&L, Met-Ed and Penelec

Prior to February 2005, FirstEnergy and OE, Penn, CEI, TE, JCP&L, Met-Ed and Penelec (the "Reporting Subsidiaries") recommended to persons who were insiders of both FirstEnergy and a Reporting Subsidiary or Reporting Subsidiaries that single insider reports be filed with respect to FirstEnergy and the Reporting Subsidiaries rather than separate reports for each. This position was based in part on an instruction to the insider reporting forms that applies in the case of registered public utility holding companies. Insiders of FirstEnergy and the Reporting Subsidiaries filed Forms 3 in this manner and further, did not set forth information about any Reporting Subsidiary on grounds that they had no holdings of any such issuer.

It recently came to FirstEnergy's attention that there is a difference of opinion as to the proper method of reporting where a subsidiary of a registered public utility holding company has equity securities registered under the Securities Exchange Act of 1934 (as do the Reporting Subsidiaries). SEC guidance in this area is unclear, and industry practice varies. After further review, FirstEnergy and the Reporting Subsidiaries determined to recommend that their insiders follow a more conservative approach and file separate reports for each Reporting Subsidiary.

Accordingly, in March 2005, Forms 3 will be filed on behalf of the following insiders in respect of the Reporting Subsidiaries indicated: Richard H. Marsh, Leila L. Vespoli, Charles E. Jones, Harvey L. Wagner, Thomas C. Navin, in each case, for all of the Reporting Subsidiaries: Anthony J. Alexander and Richard R. Grigg, in each case, for all of the Reporting Subsidiaries except JCP&L: Gelorma E. Persson, Stanley C. Van Ness, Bradley S. Ewing, Mark A. Julian and Stephen E. Morgan, in each case, for JCP&L; Kevin J. Keough, Thomas A. Clark and Jeffrey A. Elser for OE, Ronald P. Lantzy for OE and MetEd; Dennis E. Chack and Paul W. Allison for CEI; and James M. Murray and Charles H. Krueger for TE. Although arguably these Forms are not required to be filed at all, particularly since the reporting persons have no holdings in the Reporting Subsidiaries, the Reporting Subsidiaries nonetheless are reporting these Forms 3 as having not yet been filed for purposes of this Report on Form 10-K.

ITEM 11. EXECUTIVE COMPENSATION

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

FirstEnergy, OE, CEI, TE, Penn, JCP&L, Met-Ed and Penelec –

The information required by Items 11, 12 and 13 is incorporated herein by reference to FirstEnergy's 2005 Proxy Statement filed with the SEC pursuant to Regulation 14A.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

A summary of the audit and audit-related fees rendered by PricewaterhouseCoopers LLP for the years ended December 31, 2004 and 2003 are as follows:

Company	Audit Fees[1] 2004	Audit Fees[1] 2003	Audit-Related Fees[2] 2004	Audit-Related Fees[2] 2003
		(In thousands)		
OE	$ 1,036	$ 676	$ –	$ 58
CEI	797	806	–	54
TE	650	684	–	48
Penn	624	230	–	18
JCP&L	810	402	–	28
Met-Ed	609	377	–	22
Penelec	595	275	–	22
Other subsidiaries	1,542	983	18	182
Total FirstEnergy	$ 6,663	$ 4,433	$ 18	$ 432

(1) Professional services rendered for the audits of FirstEnergy's annual financial statements and reviews of financial statements included in FirstEnergy's Quarterly Reports on Form 10-Q and for services in connection with statutory and regulatory filings or engagements, including comfort letters and consents for financings and filings made with the SEC.

(2) Assurance and related services principally related to: (i) audits of employee benefit plans; (ii) consultation to ensure appropriate accounting and reporting in connection with FIN 46 and the Rate Stabilization Plan (OE, CEI and TE); and (iii) assistance with Sarbanes-Oxley.

Tax and Other Fees

There were no fees billed to FirstEnergy for tax services or other services not discussed above for the years ended December 31, 2004 and December 31, 2003.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES AND REPORTS ON FORM 8-K

(a) 1. Financial Statements

Included in Part II of this report and incorporated herein by reference to the respective company's 2004 Annual Report to Stockholders (Exhibit 13 below) at the pages indicated.

	First-Energy	OE	Penn	CEI	TE	JCP&L	Met-Ed	Penelec
Management Report	1	1	1	1	1	1	1	1
Report of Independent Registered Public Accounting Firm	2	2	2	2	2	2	2	2
Statements of Income–Three Years Ended December 31, 2004	39	17	14	16	17	14	14	13
Balance Sheets–December 31, 2004 and 2003	40	18	15	17	18	15	15	14
Statements of Capitalization–December 31, 2004 and 2003	41-43	19-20	16	18	19	16	16	15
Statements of Common Stockholders' Equity–Three Years Ended December 31, 2004	44	21	17	19	20	17	17	16
Statements of Preferred Stock–Three Years Ended December 31, 2004	45	21	17	19	20	17	17	16
Statements of Cash Flows–Three Years Ended December 31, 2004	46	22	18	20	21	18	18	17
Statements of Taxes–Three Years Ended December 31, 2004	47	23	19	21	22	19	19	18
Notes to Financial Statements	48-85	24-44	20-35	22-41	23-43	20-35	20-36	19-34

2. Financial Statement Schedules

Included in Part IV of this report:

	First-Energy	OE	Penn	CEI	TE	JCP&L	Met-Ed	Penelec
Report of Independent Registered Public Accounting Firm	65	66	69	67	68	70	71	72
Schedule – Three Years Ended December 31, 2004: II – Consolidated Valuation and Qualifying Accounts	73	74	77	75	76	78	79	80

Schedules other than the schedule listed above are omitted for the reason that they are not required or are not applicable, or the required information is shown in the financial statements or notes thereto.

3. Exhibits – FirstEnergy

Exhibit Number	
3-1	Articles of Incorporation constituting FirstEnergy Corp.'s Articles of Incorporation, dated September 17, 1996. (September 17, 1996 Form 8-K, Exhibit C)
3-1(a)	Amended Articles of Incorporation of FirstEnergy Corp. (Registration No. 333-21011, Exhibit (3)-1)
3-2	Regulations of FirstEnergy Corp. (September 17, 1996 Form 8-K, Exhibit D)
3-2(a)	FirstEnergy Corp. Amended Code of Regulations. (Registration No. 333-21011, Exhibit (3)-2)
4-1	Rights Agreement (December 1, 1997 Form 8-K, Exhibit 4.1)
4-2	FirstEnergy Corp. to The Bank of New York, Supplemental Indenture, dated November 7, 2001. (2001 Form 10-K, Exhibit 4-2)
(C)10-1	FirstEnergy Corp. Executive and Director Incentive Compensation Plan, revised November 15, 1999. (1999 Form 10-K, Exhibit 10-1)
(C)10-2	Amended FirstEnergy Corp. Deferred Compensation Plan for Directors, revised November 15, 1999. (1999 Form 10-K, Exhibit 10-2)
(C)10-3	Form of Employment, severance and change of control agreement between FirstEnergy Corp. and the following executive officers: L.L. Vespoli, C.B. Snyder, and R.H. Marsh, through December 31, 2005 (1999 Form 10-K, Exhibit 10-3)
(C)10-4	FirstEnergy Corp. Supplemental Executive Retirement Plan, amended January 1, 1999. (1999 Form 10-K, Exhibit 10-4)
(C)10-5	FirstEnergy Corp. Executive Incentive Compensation Plan. (1999 Form 10-K, Exhibit 10-5)
10-6	Restricted stock agreement between FirstEnergy Corp. and A. J. Alexander. (1999 Form 10-K, Exhibit 10-6)
(C)10-7	FirstEnergy Corp. Executive and Director Incentive Compensation Plan. (1998 Form 10-K, Exhibit 10-1)
(C)10-8	Amended FirstEnergy Corp. Deferred Compensation Plan for Directors, amended February 15, 1999. (1998 Form 10-K, Exhibit 10-2)
10-9	Restricted Stock Agreement between FirstEnergy Corp. and A. J. Alexander. (2000 Form 10-K, Exhibit 10-9)
10-10	Restricted Stock Agreement between FirstEnergy Corp. and H. P. Burg. (2000 Form 10-K, Exhibit 10-10)
10-11	Stock Option Agreement between FirstEnergy Corp. and officers dated November 22, 2000. (2000 Form 10-K, Exhibit 10-11)

Exhibit Number	
10-12	Stock Option Agreement between FirstEnergy Corp. and officers dated March 1, 2000. (2000 Form 10-K, Exhibit 10-12)
10-13	Stock Option Agreement between FirstEnergy Corp. and director dated January 1, 2000. (2000 Form 10-K, Exhibit 10-13)
10-14	Stock Option Agreement between FirstEnergy Corp. and two directors dated January 1, 2001. (2000 Form 10-K, Exhibit 10-14)
(C)10-15	Executive and Director Incentive Compensation Plan dated May 15, 2001. (2001 Form 10-K, Exhibit 10-15)
(C)10-16	Amended FirstEnergy Corp. Deferred Compensation Plan for Directors, revised September 18, 2000. (2001 Form 10-K, Exhibit 10-16)
10-17	Stock Option Agreements between FirstEnergy Corp. and Officers dated May 16, 2001. (2001 Form 10-K, Exhibit 10-17)
10-18	Form of Restricted Stock Agreements between FirstEnergy Corp. and Officers. (2001 Form 10-K, Exhibit 10-18)
10-19	Stock Option Agreements between FirstEnergy Corp. and One Director dated January 1, 2002. (2001 Form 10-K, Exhibit 10-19)
(C)10-20	FirstEnergy Corp. Executive Deferred Compensation Plan. (2001 Form 10-K, Exhibit 10-20)
(C)10-21	Executive Incentive Compensation Plan-Tier 2. (2001 Form 10-K, Exhibit 20-21)
(C)10-22	Executive Incentive Compensation Plan-Tier 3. (2001 Form 10-K, Exhibit 20-22)
(C)10-23	Executive Incentive Compensation Plan-Tier 4. (2001 Form 10-K, Exhibit 10-23)
(C)10-24	Executive Incentive Compensation Plan-Tier 5. (2001 Form 10-K, Exhibit 10-24)
10-25	Amendment to GPU, Inc. 1990 Stock Plan for Employees of GPU, Inc. and Subsidiaries, effective April 5, 2001. (2001 Form 10-K, Exhibit 10-25)
(C)10-26	Form of Amendment, effective November 7, 2001, to GPU, Inc. 1990 Stock Plan for Employees of GPU, Inc. and Subsidiaries, Deferred Remuneration Plan for Outside Directors of GPU, Inc., and Retirement Plan for Outside Directors of GPU, Inc. (2001 Form 10-K, Exhibit 10-26)
10-27	GPU, Inc. Stock Option and Restricted Stock Plan for MYR Group, Inc. Employees. (2001 Form 10-K, Exhibit 10-27)
10-28	Executive and Director Stock Option Agreement dated June 11, 2002. (2002 Form 10-K, Exhibit 10-28).
10-29	Director Stock Option Agreement. (2002 Form 10-K, Exhibit 10-29).
(C)10-30	Executive and Director Executive Incentive Compensation Plan, Amendment dated May 21, 2002. (2002 Form 10-K, Exhibit 10-30).
(C)10-31	Directors Deferred Compensation Plan, Revised Nov. 19, 2002. (2002 Form 10-K, Exhibit 10-31).
(C)10-32	Executive Incentive Compensation Plan 2002. (2002 Form 10-K, Exhibit 10-32).
10-33	GPU, Inc. 1990 Stock Plan for Employees of GPU, Inc. and Subsidiaries as amended and restated to reflect amendments through June 3, 1999. (1999 Form 10-K, Exhibit 10-V, File No. 1-6047, GPU, Inc.)
10-34	Form of 1998 Stock Option Agreement under the GPU, Inc. 1990 Stock Plan for Employees of GPU, Inc. and Subsidiaries. (1997 Form 10-K, Exhibit 10-Q, File No. 1-6047, GPU, Inc.)

Exhibit Number	
10-35	Form of 1999 Stock Option Agreement under the GPU, Inc. 1990 Stock Plan for Employees of GPU, Inc. and Subsidiaries. (1999 Form 10-K, Exhibit 10-W, File No. 1-6047, GPU, Inc.)
10-36	Form of 2000 Stock Option Agreement under the GPU, Inc. 1990 Stock Plan for Employees of GPU, Inc. and Subsidiaries. (2000 Form 10-K, Exhibit 10-W, File No. 1-6047, GPU, Inc.)
(C)10-37	Deferred Remuneration Plan for Outside Directors of GPU, Inc. as amended and restated effective August 8, 2000. (2000 Form 10-K, Exhibit 10-O, File No. 1-6047, GPU, Inc.)
(C)10-38	Retirement Plan for Outside Directors of GPU, Inc. as amended and restated as of August 8, 2000. (2000 Form 10-K, Exhibit 10-N, File No. 1-6047, GPU, Inc.)
(C)10-39	Forms of Estate Enhancement Program Agreements entered into by certain former GPU directors. (1999 Form 10-K, Exhibit 10-JJ, File No. 1-6047, GPU, Inc.)
(A)10-40	$1Billion Three-Year Credit Agreement dated as of June 22, 2004 among FirstEnergy Corp., the Banks named therein, Citicorp USA, Inc., as Administrative and Fronting Bank and Barclays Bank PLC as Fronting Bank.
(A)10-41	$375,000,000 Three-Year Credit Agreement dated as of October 23, 2003 among FirstEnergy Corp., the Banks named therein, Citibank, N.A., as Administrative Agent and Bank One, NA, as Fronting Bank.
(C)10-42	Deferred Compensation Plan for Outside Directors, effective November 7, 2001, incorporated by reference to Exhibit 4(f), Form S-8, File No. 333-101472.
(C)10-43	Employment Agreement between FirstEnergy and an officer dated July 20, 2004, (September 30, 2004 Form 10-Q, Exhibit 10-41).
(C)10-44	Stock Option Agreement between FirstEnergy and an officer dated August 20, 2004. (September 30, 2004 Form 10-Q, Exhibit 10-42).
(C)10-45	Restricted Stock Agreement between FirstEnergy and an officer dated August 20, 2004. (September 30, 2004 Form 10-Q, Exhibit 10-43).
(C)10-46	Executive Bonus Plan between FirstEnergy and Officers dated October 31, 2004. (September 30, 2004 Form 10-Q, Exhibit 10-44).
(A)(C)10-47	Form of Employment, Severance, and Change of Control Agreement, between FirstEnergy and A. J. Alexander.
(A)(C)10-48	Form of Employment, Severance, and Change of Control Agreement, Tier 1, between FirstEnergy and the following executive officers: C.B. Snyder, L.L. Vespoli, and R.H. Marsh (effective January 1, 2006).
(A)(C)10-49	Form of Employment, Severance, and Change of Control Agreement, Tier 1, between FirstEnergy and the following executive officers: L.M. Cavalier, M.T. Clark, and R.R. Grigg.
(A)(C)10-50	Form of Employment, Severance, and Change of Control Agreement, Tier 2, between FirstEnergy and the following executive officers: K.J. Keough and K.W. Dindo (effective January 1, 2006).
(A)(C)10-51	Form of Employment, Severance, and Change of Control Agreement, Tier 2, between FirstEnergy and G. L. Pipitone.
(A)(C)10-52	Executive and Director Incentive Compensation Plan, Amendment dated January 18, 2005.
(A)(C)10-53	Form of Restricted Stock Agreements, between FirstEnergy and Officers.
(A)(C)10-54	Form of Restricted Stock Unit Agreements (Performance Adjusted), between FirstEnergy and Officers.
(A)(C)10-55	Form of Restricted Stock Agreement, between FirstEnergy and an officer.
(A)12.1	Consolidated fixed charge ratios.

Exhibit
Number

(A)13	FirstEnergy 2004 Annual Report to Stockholders. (Only those portions expressly incorporated by reference in this Form 10-K are to be deemed "filed" with the SEC.)
(A)21	List of Subsidiaries of the Registrant at December 31, 2004.
(A)23	Consent of Independent Registered Public Accounting Firm.
(A)31.1	Certification of chief executive officer, as adopted pursuant to Rule 13a-15(e)/15d-15(e) (FirstEnergy, OE, CEI, TE, Penn, Met-Ed and Penelec).
(A)31.2	Certification of chief financial officer, as adopted pursuant to Rule 13a-15(e)/15d-15(e) (FirstEnergy, OE, CEI, TE, Penn, JCP&L, Met-Ed and Penelec).
(A)32.1	Certification of chief executive officer and chief financial officer, pursuant to 18 U.S.C. §1350 (FirstEnergy, OE, CEI, TE, Penn, Met-Ed and Penelec).
(A)	Provided herein in electronic format as an exhibit.
(C)	Management contract or compensatory plan contract or arrangement filed pursuant to Item 601 of Regulation S-K.

(B) 3. Exhibits – Ohio Edison

2-1	Agreement and Plan of Merger, dated as of September 13, 1996, between Ohio Edison Company (OE) and Centerior Energy Corporation. (September 17, 1996 Form 8-K, Exhibit 2-1)
3-1	Amended Articles of Incorporation, Effective June 21, 1994, constituting OE's Articles of Incorporation. (1994 Form 10-K, Exhibit 3-1)
(A)3-2	Amendment to Articles of Incorporation, Effective November 12, 1999
3-3	Amended and Restated Code of Regulations, amended March 15, 2002. (2001 Form 10-K, Exhibit 3-2)
(B)4-1	Indenture dated as of August 1, 1930 between OE and Bankers Trust Company, (now the Bank of New York), as Trustee, as amended and supplemented by Supplemental Indentures:

Dated as of	File Reference	Incorporated by Reference to Exhibit No.
March 3, 1931	2-1725	B1, B-1(a),B-1(b)
November 1, 1935	2-2721	B-4
January 1, 1937	2-3402	B-5
September 1, 1937	Form 8-A	B-6
June 13, 1939	2-5462	7(a)-7
August 1, 1974	Form 8-A, August 28, 1974	2(b)
July 1, 1976	Form 8-A, July 28, 1976	2(b)
December 1, 1976	Form 8-A, December 15, 1976	2(b)
June 15, 1977	Form 8-A, June 27, 1977	2(b)
Supplemental Indentures:		
September 1, 1944	2-61146	2(b)(2)
April 1, 1945	2-61146	2(b)(2)
September 1, 1948	2-61146	2(b)(2)
May 1, 1950	2-61146	2(b)(2)
January 1, 1954	2-61146	2(b)(2)
May 1, 1955	2-61146	2(b)(2)
August 1, 1956	2-61146	2(b)(2)
March 1, 1958	2-61146	2(b)(2)
April 1, 1959	2-61146	2(b)(2)
June 1, 1961	2-61146	2(b)(2)
September 1, 1969	2-34351	2(b)(2)
May 1, 1970	2-37146	2(b)(2)

Exhibit
Number

Dated as of	File Reference	Exhibit No.
September 1, 1970	2-38172	2(b)(2)
June 1, 1971	2-40379	2(b)(2)
August 1, 1972	2-44803	2(b)(2)
September 1, 1973	2-48867	2(b)(2)
May 15, 1978	2-66957	2(b)(4)
February 1, 1980	2-66957	2(b)(5)
April 15, 1980	2-66957	2(b)(6)
June 15, 1980	2-68023	(b)(4)(b)(5)
October 1, 1981	2-74059	(4)(d)
October 15, 1981	2-75917	(4)(e)
February 15, 1982	2-75917	(4)(e)
July 1, 1982	2-89360	(4)(d)
March 1, 1983	2-89360	(4)(e)
March 1, 1984	2-89360	(4)(f)
September 15, 1984	2-92918	(4)(d)
September 27, 1984	33-2576	(4)(d)
November 8, 1984	33-2576	(4)(d)
December 1, 1984	33-2576	(4)(d)
December 5, 1984	33-2576	(4)(e)
January 30, 1985	33-2576	(4)(e)
February 25, 1985	33-2576	(4)(e)
July 1, 1985	33-2576	(4)(e)
October 1, 1985	33-2576	(4)(e)
January 15, 1986	33-8791	(4)(d)
May 20, 1986	33-8791	(4)(d)
June 3, 1986	33-8791	(4)(e)
October 1, 1986	33-29827	(4)(d)
August 25, 1989	33-34663	(4)(d)
February 15, 1991	33-39713	(4)(d)
May 1, 1991	33-45751	(4)(d)
May 15, 1991	33-45751	(4)(d)
September 15, 1991	33-45751	(4)(d)
April 1, 1992	33-48931	(4)(d)
June 15, 1992	33-48931	(4)(d)
September 15, 1992	33-48931	(4)(e)
April 1, 1993	33-51139	(4)(d)
June 15, 1993	33-51139	(4)(d)
September 15, 1993	33-51139	(4)(d)
November 15, 1993	1-2578	(4)(2)
April 1, 1995	1-2578	(4)(2)
May 1, 1995	1-2578	(4)(2)
July 1, 1995	1-2578	(4)(2)
June 1, 1997	1-2578	(4)(2)
April 1, 1998	1-2578	(4)(2)
June 1, 1998	1-2578	(4)(2)
September 29, 1999	1-2578	(4)(2)
April 1, 2000	1-2578	(4)(2)(a)
April 1, 2000	1-2578	(4)(2)(b)
June 1, 2001	1-2578	
February 1, 2003	1-2578	4(2)
March 1, 2003	1-2578	4(2)
August 1, 2003	1-2578	4(2)
(A)June 1, 2004	1-2578	4(2)
(A)June 1, 2004	1-2578	4(2)
(A)December 1, 2004	1-2578	4(2)

(B) 4-2 General Mortgage Indenture and Deed of Trust dated as of January 1, 1998 between OE and the Bank of New York, as Trustee, as amended and supplemented by Supplemental Indentures; (Registration No. 333-05277, Exhibit 4(g)).

Exhibit
Number

Dated as of	File Reference	Incorporated by Reference to Exhibit No.
February 1, 2003	1-2578	4-2
March 1, 2003	1-2578	4-2
August 1, 2003	1-2578	4-2
(A)June 1, 2004	1-2578	4-2
(A)June 1, 2004	1-2578	4-2
(A)December 1, 2004	1-2578	4-2

4-3 Indenture dated as of April 1, 2003 between OE and The Bank of New York, as Trustee.

10-1 Administration Agreement between the CAPCO Group dated as of September 14, 1967. (Registration No. 2-43102, Exhibit 5(c)(2)

10-2 Amendment No. 1 dated January 4, 1974 to Administration Agreement between the CAPCO Group dated as of September 14, 1967. (Registration No. 2-68906, Exhibit 5(c)(3))

10-3 Transmission Facilities Agreement between the CAPCO Group dated as of September 14, 1967. (Registration No. 2-43102, Exhibit 5(c)(3))

10-4 Amendment No. 1 dated as of January 1, 1993 to Transmission Facilities Agreement between the CAPCO Group dated as of September 14, 1967. (1993 Form 10-K, Exhibit 10-4)

10-5 Agreement for the Termination or Construction of Certain Agreements effective September 1, 1980 among the CAPCO Group. (Registration No. 2-68906, Exhibit 10-4)

10-6 Amendment dated as of December 23, 1993 to Agreement for the Termination or Construction of Certain Agreements effective September 1, 1980 among the CAPCO Group. (1993 Form 10-K, Exhibit 10-6)

10-7 CAPCO Basic Operating Agreement, as amended September 1, 1980. (Registration No. 2-68906, Exhibit 10-5)

10-8 Amendment No. 1 dated August 1, 1981, and Amendment No. 2 dated September 1, 1982 to CAPCO Basic Operating Agreement, as amended September 1, 1980. (September 30, 1981 Form 10-Q, Exhibit 20-1 and 1982 Form 10-K, Exhibit 19-3, respectively)

10-9 Amendment No. 3 dated July 1, 1984 to CAPCO Basic Operating Agreement, as amended September 1, 1980. (1985 Form 10-K, Exhibit 10-7)

10-10 Basic Operating Agreement between the CAPCO Companies as amended October 1, 1991. (1991 Form 10-K, Exhibit 10-8)

10-11 Basic Operating Agreement between the CAPCO Companies as amended January 1, 1993. (1993 Form 10-K, Exhibit 10-11)

10-12 Memorandum of Agreement effective as of September 1, 1980 among the CAPCO Group. (1982 Form 10-K, Exhibit 19-2)

10-13 Operating Agreement for Beaver Valley Power Station Units Nos. 1 and 2 as Amended and Restated September 15, 1987, by and between the CAPCO Companies. (1987 Form 10-K, Exhibit 10-15)

10-14 Construction Agreement with respect to Perry Plant between the CAPCO Group dated as of July 22, 1974. (Registration No. 2-52251 of Toledo Edison Company, Exhibit 5(yy))

10-15 Amendment No. 3 dated as of October 31, 1980 to the Bond Guaranty dated as of October 1, 1973, as amended, with respect to the CAPCO Group. (Registration No. 2-68906 of Pennsylvania Power Company, Exhibit 10-16)

Exhibit Number	
10-16	Amendment No. 4 dated as of July 1, 1985 to the Bond Guaranty dated as October 1, 1973, as amended, by the CAPCO Companies to National City Bank as Bond Trustee. (1985 Form 10-K, Exhibit 10-30)
10-17	Amendment No. 5 dated as of May 1, 1986, to the Bond Guaranty by the CAPCO Companies to National City Bank as Bond Trustee. (1986 Form 10-K, Exhibit 10-33)
10-18	Amendment No. 6A dated as of December 1, 1991, to the Bond Guaranty dated as of October 1, 1973, by The Cleveland Electric Illuminating Company, Duquesne Light Company, Ohio Edison Company, Pennsylvania Power Company, The Toledo Edison Company to National City Bank, as Bond Trustee. (1991 Form 10-K, Exhibit 10-33)
10-19	Amendment No. 6B dated as of December 30, 1991, to the Bond Guaranty dated as of October 1, 1973 by The Cleveland Electric Illuminating Company, Duquesne Light Company, Ohio Edison Company, Pennsylvania Power Company, The Toledo Edison Company to National City Bank, as Bond Trustee. (1991 Form 10-K, Exhibit 10-34)
10-20	Bond Guaranty dated as of December 1, 1991, by The Cleveland Electric Illuminating Company, Duquesne Light Company, Ohio Edison Company, Pennsylvania Power Company, The Toledo Edison Company to National City Bank, as Bond Trustee. (1991 Form 10-K, Exhibit 10-35)
10-21	Memorandum of Understanding dated March 31, 1985 among the CAPCO Companies. (1985 Form 10-K, Exhibit 10-35)
(C)10-22	Ohio Edison System Executive Supplemental Life Insurance Plan. (1995 Form 10-K, Exhibit 10-44)
(C)10-23	Ohio Edison System Executive Incentive Compensation Plan. (1995 Form 10-K, Exhibit 10-45.)
(C)10-24	Ohio Edison System Restated and Amended Executive Deferred Compensation Plan. (1995 Form 10-K, Exhibit 10-46.)
(C)10-25	Ohio Edison System Restated and Amended Supplemental Executive Retirement Plan. (1995 Form 10-K, Exhibit 10-47.)
(C)10-28	Severance pay agreement between Ohio Edison Company and A. J. Alexander. (1995 Form 10-K, Exhibit 10-50.)
(D)10-30	Participation Agreement dated as of March 16, 1987 among Perry One Alpha Limited Partnership, as Owner Participant, the Original Loan Participants listed in Schedule 1 Hereto, as Original Loan Participants, PNPP Funding Corporation, as Funding Corporation, The First National Bank of Boston, as Owner Trustee, Irving Trust Company, as Indenture Trustee and Ohio Edison Company, as Lessee. (1986 Form 10-K, Exhibit 28-1.)
(D)10-31	Amendment No. 1 dated as of September 1, 1987 to Participation Agreement dated as of March 16, 1987 among Perry One Alpha Limited Partnership, as Owner Participant, the Original Loan Participants listed in Schedule 1 thereto, as Original Loan Participants, PNPP Funding Corporation, as Funding Corporation, The First National Bank of Boston, as Owner Trustee, Irving Trust Company (now The Bank of New York), as Indenture Trustee, and Ohio Edison Company, as Lessee. (1991 Form 10-K, Exhibit 10-46.)
(D)10-32	Amendment No. 3 dated as of May 16, 1988 to Participation Agreement dated as of March 16, 1987, as amended among Perry One Alpha Limited Partnership, as Owner Participant, PNPP Funding Corporation, The First National Bank of Boston, as Owner Trustee, Irving Trust Company, as Indenture Trustee, and Ohio Edison Company, as Lessee. (1992 Form 10-K, Exhibit 10-47.)
(D)10-33	Amendment No. 4 dated as of November 1, 1991 to Participation Agreement dated as of March 16, 1987 among Perry One Alpha Limited Partnership, as Owner Participant, PNPP Funding Corporation, as Funding Corporation, PNPP II Funding Corporation, as New Funding Corporation, The First National Bank of Boston, as Owner Trustee, The Bank of New York, as Indenture Trustee and Ohio Edison Company, as Lessee. (1991 Form 10-K, Exhibit 10-47.)

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(D)10-34	Amendment No. 5 dated as of November 24, 1992 to Participation Agreement dated as of March 16, 1987, as amended, among Perry One Alpha Limited Partnership, as Owner Participant, PNPP Funding Corporation, as Funding Corporation, PNPP II Funding Corporation, as New Funding Corporation, The First National Bank of Boston, as Owner Trustee, The Bank of New York, as Indenture Trustee and Ohio Edison Company as Lessee. (1992 Form 10-K, Exhibit 10-49.)
(D)10-35	Amendment No. 6 dated as of January 12, 1993 to Participation Agreement dated as of March 16, 1987 among Perry One Alpha Limited Partnership, as Owner Participant, PNPP Funding Corporation, as Funding Corporation, PNPP II Funding Corporation, as New Funding Corporation, The First National Bank of Boston, as Owner Trustee, The Bank of New York, as Indenture Trustee and Ohio Edison Company, as Lessee. (1992 Form 10-K, Exhibit 10-50.)
(D)10-36	Amendment No. 7 dated as of October 12, 1994 to Participation Agreement dated as of March 16, 1987 as amended, among Perry One Alpha Limited Partnership, as Owner Participant, PNPP Funding Corporation, as Funding Corporation, PNPP II Funding Corporation, as New Funding Corporation, The First National Bank of Boston, as Owner Trustee, The Bank of New York, as Indenture Trustee and Ohio Edison Company, as Lessee. (1994 Form 10-K, Exhibit 10-54.)
(D)10-37	Facility Lease dated as of March 16, 1987 between The First National Bank of Boston, as Owner Trustee, with Perry One Alpha Limited Partnership, Lessor, and Ohio Edison Company, Lessee. (1986 Form 10-K, Exhibit 28-2.)
(D)10-38	Amendment No. 1 dated as of September 1, 1987 to Facility Lease dated as of March 16, 1997 between The First National Bank of Boston, as Owner Trustee, Lessor and Ohio Edison Company, Lessee. (1991 Form 10-K, Exhibit 10-49.)
(D)10-39	Amendment No. 2 dated as of November 1, 1991, to Facility Lease dated as of March 16, 1987, between The First National Bank of Boston, as Owner Trustee, Lessor and Ohio Edison Company, Lessee. (1991 Form 10-K, Exhibit 10-50.)
(D)10-40	Amendment No. 3 dated as of November 24, 1992 to Facility Lease dated as March 16, 1987 as amended, between The First National Bank of Boston, as Owner Trustee, with Perry One Alpha Limited partnership, as Owner Participant and Ohio Edison Company, as Lessee. (1992 Form 10-K, Exhibit 10-54.)
(D)10-41	Amendment No. 4 dated as of January 12, 1993 to Facility Lease dated as of March 16, 1987 as amended, between, The First National Bank of Boston, as Owner Trustee, with Perry One Alpha Limited Partnership, as Owner Participant, and Ohio Edison Company, as Lessee. (1994 Form 10-K, Exhibit 10-59.)
(D)10-42	Amendment No. 5 dated as of October 12, 1994 to Facility Lease dated as of March 16, 1987 as amended, between, The First National Bank of Boston, as Owner Trustee, with Perry One Alpha Limited Partnership, as Owner Participant, and Ohio Edison Company, as Lessee. (1994 Form 10-K, Exhibit 10-60.)
(D)10-43	Letter Agreement dated as of March 19, 1987 between Ohio Edison Company, Lessee, and The First National Bank of Boston, Owner Trustee under a Trust dated March 16, 1987 with Chase Manhattan Realty Leasing Corporation, required by Section 3(d) of the Facility Lease. (1986 Form 10-K, Exhibit 28-3.)
(D)10-44	Ground Lease dated as of March 16, 1987 between Ohio Edison Company, Ground Lessor, and The First National Bank of Boston, as Owner Trustee under a Trust Agreement, dated as of March 16, 1987, with the Owner Participant, Tenant. (1986 Form 10-K, Exhibit 28-4.)
(D)10-45	Trust Agreement dated as of March 16, 1987 between Perry One Alpha Limited Partnership, as Owner Participant, and The First National Bank of Boston. (1986 Form 10-K, Exhibit 28-5.)
(D)10-46	Trust Indenture, Mortgage, Security Agreement and Assignment of Facility Lease dated as of March 16, 1987 between The First National Bank of Boston, as Owner Trustee under a Trust Agreement dated as of March 16, 1987 with Perry One Alpha Limited Partnership, and Irving Trust Company, as Indenture Trustee. (1986 Form 10-K, Exhibit 28-6.)

Exhibit Number	
(D)10-47	Supplemental Indenture No. 1 dated as of September 1, 1987 to Trust Indenture, Mortgage, Security Agreement and Assignment of Facility Lease dated as of March 16, 1987 between The First National Bank of Boston as Owner Trustee and Irving Trust Company (now The Bank of New York), as Indenture Trustee. (1991 Form 10-K, Exhibit 10-55.)
(D)10-48	Supplemental Indenture No. 2 dated as of November 1, 1991 to Trust Indenture, Mortgage, Security Agreement and Assignment of Facility Lease dated as of March 16, 1987 between The First National Bank of Boston, as Owner Trustee and The Bank of New York, as Indenture Trustee. (1991 Form 10-K, Exhibit 10-56.)
(D)10-49	Tax Indemnification Agreement dated as of March 16, 1987 between Perry One, Inc. and PARock Limited Partnership as General Partners and Ohio Edison Company, as Lessee. (1986 Form 10-K, Exhibit 28-7.)
(D)10-50	Amendment No. 1 dated as of November 1, 1991 to Tax Indemnification Agreement dated as of March 16, 1987 between Perry One, Inc. and PARock Limited Partnership and Ohio Edison Company. (1991 Form 10-K, Exhibit 10-58.)
(D)10-51	Amendment No. 2 dated as of January 12, 1993 to Tax Indemnification Agreement dated as of March 16, 1987 between Perry One, Inc. and PARock Limited Partnership and Ohio Edison Company. (1994 Form 10-K, Exhibit 10-69.)
(D)10-52	Amendment No. 3 dated as of October 12, 1994 to Tax Indemnification Agreement dated as of March 16, 1987 between Perry One, Inc. and PARock Limited Partnership and Ohio Edison Company. (1994 Form 10-K, Exhibit 10-70.)
(D)10-53	Partial Mortgage Release dated as of March 19, 1987 under the Indenture between Ohio Edison Company and Bankers Trust Company, as Trustee, dated as of the 1st day of August 1930. (1986 Form 10-K, Exhibit 28-8.)
(D)10-54	Assignment, Assumption and Further Agreement dated as of March 16, 1987 among The First National Bank of Boston, as Owner Trustee under a Trust Agreement, dated as of March 16, 1987, with Perry One Alpha Limited Partnership, The Cleveland Electric Illuminating Company, Duquesne Light Company, Ohio Edison Company, Pennsylvania Power Company and Toledo Edison Company. (1986 Form 10-K, Exhibit 28-9.)
(D)10-55	Additional Support Agreement dated as of March 16, 1987 between The First National Bank of Boston, as Owner Trustee under a Trust Agreement, dated as of March 16, 1987, with Perry One Alpha Limited Partnership, and Ohio Edison Company. (1986 Form 10-K, Exhibit 28-10.)
(D)10-56	Bill of Sale, Instrument of Transfer and Severance Agreement dated as of March 19, 1987 between Ohio Edison Company, Seller, and The First National Bank of Boston, as Owner Trustee under a Trust Agreement, dated as of March 16, 1987, with Perry One Alpha Limited Partnership. (1986 Form 10-K, Exhibit 28-11.)
(D)10-57	Easement dated as of March 16, 1987 from Ohio Edison Company, Grantor, to The First National Bank of Boston, as Owner Trustee under a Trust Agreement, dated as of March 16, 1987, with Perry One Alpha Limited Partnership, Grantee. (1986 Form 10-K, File Exhibit 28-12.)
10-58	Participation Agreement dated as of March 16, 1987 among Security Pacific Capital Leasing Corporation, as Owner Participant, the Original Loan Participants listed in Schedule 1 Hereto, as Original Loan Participants, PNPP Funding Corporation, as Funding Corporation, The First National Bank of Boston, as Owner Trustee, Irving Trust Company, as Indenture Trustee and Ohio Edison Company, as Lessee. (1986 Form 10-K, as Exhibit 28-13.)
10-59	Amendment No. 1 dated as of September 1, 1987 to Participation Agreement dated as of March 16, 1987 among Security Pacific Capital Leasing Corporation, as Owner Participant, The Original Loan Participants Listed in Schedule 1 thereto, as Original Loan Participants, PNPP Funding Corporation, as Funding Corporation, The First National Bank of Boston, as Owner Trustee, Irving Trust Company, as Indenture Trustee and Ohio Edison Company, as Lessee. (1991 Form 10-K, Exhibit 10-65.)

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10-60	Amendment No. 4 dated as of November 1, 1991, to Participation Agreement dated as of March 16, 1987 among Security Pacific Capital Leasing Corporation, as Owner Participant, PNPP Funding Corporation, as Funding Corporation, PNPP II Funding Corporation, as New Funding Corporation, The First National Bank of Boston, as Owner Trustee, The Bank of New York, as Indenture Trustee and Ohio Edison Company, as Lessee. (1991 Form 10-K, Exhibit 10-66.)
10-61	Amendment No. 5 dated as of November 24, 1992 to Participation Agreement dated as of March 16, 1987 as amended among Security Pacific Capital Leasing Corporation, as Owner Participant, PNPP Funding Corporation, as Funding Corporation, PNNP II Funding Corporation, as New Funding Corporation, The First National Bank of Boston, as Owner Trustee, The Bank of New York, as Indenture Trustee and Ohio Edison Company, as Lessee. (1992 Form 10-K, Exhibit 10-71.)
10-62	Amendment No. 6 dated as of January 12, 1993 to Participation Agreement dated as of March 16, 1987 as amended among Security Pacific Capital Leasing Corporation, as Owner Participant, PNPP Funding Corporation, as Funding Corporation, PNPP II Funding Corporation, as New Funding Corporation, The First National Bank of Boston, as Owner Trustee, The Bank of New York, as Indenture Trustee and Ohio Edison Company, as Lessee. (1994 Form 10-K, Exhibit 10-80.)
10-63	Amendment No. 7 dated as of October 12, 1994 to Participation Agreement dated as of March 16, 1987 as amended among Security Pacific Capital Leasing Corporation, as Owner Participant, PNPP Funding Corporation, as Funding Corporation, PNPP II Funding Corporation, as New Funding Corporation, The First National Bank of Boston, as Owner Trustee, The Bank of New York, as Indenture Trustee and Ohio Edison Company, as Lessee. (1994 Form 10-K, Exhibit 10-81.)
10-64	Facility Lease dated as of March 16, 1987 between The First National Bank of Boston, as Owner Trustee, with Security Pacific Capital Leasing Corporation, Lessor, and Ohio Edison Company, as Lessee. (1986 Form 10-K, Exhibit 28-14.)
10-65	Amendment No. 1 dated as of September 1, 1987 to Facility Lease dated as of March 16, 1987 between The First National Bank of Boston as Owner Trustee, Lessor and Ohio Edison Company, Lessee. (1991 Form 10-K, Exhibit 10-68.)
10-66	Amendment No. 2 dated as of November 1, 1991 to Facility Lease dated as of March 16, 1987 between The First National Bank of Boston as Owner Trustee, Lessor and Ohio Edison Company, Lessee. (1991 Form 10-K, Exhibit 10-69.)
10-67	Amendment No. 3 dated as of November 24, 1992 to Facility Lease dated as of March 16, 1987, as amended, between, The First National Bank of Boston, as Owner Trustee, with Security Pacific Capital Leasing Corporation, as Owner Participant and Ohio Edison Company, as Lessee. (1992 Form 10-K, Exhibit 10-75.)
10-68	Amendment No. 4 dated as of January 12, 1993 to Facility Lease dated as of March 16, 1987 as amended between, The First National Bank of Boston, as Owner Trustee, with Security Pacific Capital Leasing Corporation, as Owner Participant, and Ohio Edison Company, as Lessee. (1992 Form 10-K, Exhibit 10-76.)
10-69	Amendment No. 5 dated as of October 12, 1994 to Facility Lease dated as of March 16, 1987 as amended between, The First National Bank of Boston, as Owner Trustee, with Security Pacific Capital Leasing Corporation, as Owner Participant, and Ohio Edison Company, as Lessee. (1994 Form 10-K, Exhibit 10-87.)
10-70	Letter Agreement dated as of March 19, 1987 between Ohio Edison Company, as Lessee, and The First National Bank of Boston, as Owner Trustee under a Trust, dated as of March 16, 1987, with Security Pacific Capital Leasing Corporation, required by Section 3(d) of the Facility Lease. (1986 Form 10-K, Exhibit 28-15.)

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10-71	Ground Lease dated as of March 16, 1987 between Ohio Edison Company, Ground Lessor, and The First National Bank of Boston, as Owner Trustee under a Trust Agreement, dated as of March 16, 1987, with Perry One Alpha Limited Partnership, Tenant. (1986 Form 10-K, Exhibit 28-16.)
10-72	Trust Agreement dated as of March 16, 1987 between Security Pacific Capital Leasing Corporation, as Owner Participant, and The First National Bank of Boston. (1986 Form 10-K, Exhibit 28-17.)
10-73	Trust Indenture, Mortgage, Security Agreement and Assignment of Facility Lease dated as of March 16, 1987 between The First National Bank of Boston, as Owner Trustee under a Trust Agreement, dated as of March 16, 1987, with Security Pacific Capital Leasing Corporation, and Irving Trust Company, as Indenture Trustee. (1986 Form 10-K, Exhibit 28-18.)
10-74	Supplemental Indenture No. 1 dated as of September 1, 1987 to Trust Indenture, Mortgage, Security Agreement and Assignment of Facility Lease dated as of March 16, 1987 between The First National Bank of Boston, as Owner Trustee and Irving Trust Company (now The Bank of New York), as Indenture Trustee. (1991 Form 10-K, Exhibit 10-74.)
10-75	Supplemental Indenture No. 2 dated as of November 1, 1991 to Trust Indenture, Mortgage, Security Agreement and Assignment of Facility Lease dated as of March 16, 1987 between The First National Bank of Boston, as Owner Trustee and The Bank of New York, as Indenture Trustee. (1991 Form 10-K, Exhibit 10-75.)
10-76	Tax Indemnification Agreement dated as of March 16, 1987 between Security Pacific Capital Leasing Corporation, as Owner Participant, and Ohio Edison Company, as Lessee. (1986 Form 10-K, Exhibit 28-19.)
10-77	Amendment No. 1 dated as of November 1, 1991 to Tax Indemnification Agreement dated as of March 16, 1987 between Security Pacific Capital Leasing Corporation and Ohio Edison Company. (1991 Form 10-K, Exhibit 10-77.)
10-78	Amendment No. 2 dated as of January 12, 1993 to Tax Indemnification Agreement dated as of March 16, 1987 between Security Pacific Capital Leasing Corporation and Ohio Edison Company. (1994 Form 10-K, Exhibit 10-96.)
10-79	Amendment No. 3 dated as of October 12, 1994 to Tax Indemnification Agreement dated as of March 16, 1987 between Security Pacific Capital Leasing Corporation and Ohio Edison Company. (1994 Form 10-K, Exhibit 10-97.)
10-80	Assignment, Assumption and Further Agreement dated as of March 16, 1987 among The First National Bank of Boston, as Owner Trustee under a Trust Agreement, dated as of March 16, 1987, with Security Pacific Capital Leasing Corporation, The Cleveland Electric Illuminating Company, Duquesne Light Company, Ohio Edison Company, Pennsylvania Power Company and Toledo Edison Company. (1986 Form 10-K, Exhibit 28-20.)
10-81	Additional Support Agreement dated as of March 16, 1987 between The First National Bank of Boston, as Owner Trustee under a Trust Agreement, dated as of March 16, 1987, with Security Pacific Capital Leasing Corporation, and Ohio Edison Company. (1986 Form 10-K, Exhibit 28-21.)
10-82	Bill of Sale, Instrument of Transfer and Severance Agreement dated as of March 19, 1987 between Ohio Edison Company, Seller, and The First National Bank of Boston, as Owner Trustee under a Trust Agreement, dated as of March 16, 1987, with Security Pacific Capital Leasing Corporation, Buyer. (1986 Form 10-K, Exhibit 28-22.)
10-83	Easement dated as of March 16, 1987 from Ohio Edison Company, Grantor, to The First National Bank of Boston, as Owner Trustee under a Trust Agreement, dated as of March 16, 1987, with Security Pacific Capital Leasing Corporation, Grantee. (1986 Form 10-K, Exhibit 28-23.)

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10-84	Refinancing Agreement dated as of November 1, 1991 among Perry One Alpha Limited Partnership, as Owner Participant, PNPP Funding Corporation, as Funding Corporation, PNPP II Funding Corporation, as New Funding Corporation, The First National Bank of Boston, as Owner Trustee, The Bank of New York, as Indenture Trustee, The Bank of New York, as Collateral Trust Trustee, The Bank of New York, as New Collateral Trust Trustee and Ohio Edison Company, as Lessee. (1991 Form 10-K, Exhibit 10-82.)
10-85	Refinancing Agreement dated as of November 1, 1991 among Security Pacific Leasing Corporation, as Owner Participant, PNPP Funding Corporation, as Funding Corporation, PNPP II Funding Corporation, as New Funding Corporation, The First National Bank of Boston, as Owner Trustee, The Bank of New York, as Indenture Trustee, The Bank of New York, as Collateral Trust Trustee, The Bank of New York as New Collateral Trust Trustee and Ohio Edison Company, as Lessee. (1991 Form 10-K, Exhibit 10-83.)
10-86	Ohio Edison Company Master Decommissioning Trust Agreement for Perry Nuclear Power Plant Unit One, Perry Nuclear Power Plant Unit Two, Beaver Valley Power Station Unit One and Beaver Valley Power Station Unit Two dated July 1, 1993. (1993 Form 10-K, Exhibit 10-94.)
10-87	Nuclear Fuel Lease dated as of March 31, 1989, between OES Fuel, Incorporated, as Lessor, and Ohio Edison Company, as Lessee. (1989 Form 10-K, Exhibit 10-62.)
10-89	Guarantee Agreement entered into by Ohio Edison Company dated as of January 17, 1991. (1990 Form 10-K, Exhibit 10-64.)
10-90	Transfer and Assignment Agreement among Ohio Edison Company and Chemical Bank, as trustee under the OE Power Contract Trust. (1990 Form 10-K, Exhibit 10-65.)
10-91	Renunciation of Payments and Assignment among Ohio Edison Company, Monongahela Power Company, West Penn Power Company, and the Potomac Edison Company dated as of January 4, 1991. (1990 Form 10-K, Exhibit 10-66.)
10-92	Transfer and Assignment Agreement dated May 20, 1994 among Ohio Edison Company and Chemical Bank, as trustee under the OE Power Contract Trust. (1994 Form 10-K, Exhibit 10-110.)
10-93	Renunciation of Payments and Assignment among Ohio Edison Company, Monongahela Power Company, West Penn Power Company, and the Potomac Edison Company dated as of May 20, 1994. (1994 Form 10-K, Exhibit 10-111.)
10-94	Transfer and Assignment Agreement dated October 12, 1994 among Ohio Edison Company and Chemical Bank, as trustee under the OE Power Contract Trust. (1994 Form 10-K, Exhibit 10-112.)
10-95	Renunciation of Payments and Assignment among Ohio Edison Company, Monongahela Power Company, West Penn Power Company, and the Potomac Edison Company dated as of October 12, 1994. (1994 Form 10-K, Exhibit 10-113.)
(E)10-96	Participation Agreement dated as of September 15, 1987, among Beaver Valley Two Pi Limited Partnership, as Owner Participant, the Original Loan Participants listed in Schedule 1 Thereto, as Original Loan Participants, BVPS Funding Corporation, as Funding Corporation, The First National Bank of Boston, as Owner Trustee, Irving Trust Company, as Indenture Trustee and Ohio Edison Company as Lessee. (1987 Form 10-K, Exhibit 28-1.)
(E)10-97	Amendment No. 1 dated as of February 1, 1988, to Participation Agreement dated as of September 15, 1987, among Beaver Valley Two Pi Limited Partnership, as Owner Participant, the Original Loan Participants listed in Schedule 1 Thereto, as Original Loan Participants, BVPS Funding Corporation, as Funding Corporation, The First National Bank of Boston, as Owner Trustee, Irving Trust Company, as Indenture Trustee and Ohio Edison Company, as Lessee. (1987 Form 10-K, Exhibit 28-2.)

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(E)10-98	Amendment No. 3 dated as of March 16, 1988 to Participation Agreement dated as of September 15, 1987, as amended, among Beaver Valley Two Pi Limited Partnership, as Owner Participant, BVPS Funding Corporation, The First National Bank of Boston, as Owner Trustee, Irving Trust Company, as Indenture Trustee and Ohio Edison Company, as Lessee. (1992 Form 10-K, Exhibit 10-99.)
(E)10-99	Amendment No. 4 dated as of November 5, 1992 to Participation Agreement dated as of September 15, 1987, as amended, among Beaver Valley Two Pi Limited Partnership, as Owner Participant, BVPS Funding Corporation, BVPS II Funding Corporation, The First National Bank of Boston, as Owner Trustee, The Bank of New York, as Indenture Trustee and Ohio Edison Company, as Lessee. (1992 Form 10-K, Exhibit 10-100.)
(E)10-100	Amendment No. 5 dated as of September 30, 1994 to Participation Agreement dated as of September 15, 1987, as amended, among Beaver Valley Two Pi Limited Partnership, as Owner Participant, BVPS Funding Corporation, BVPS II Funding Corporation, The First National Bank of Boston, as Owner Trustee, The Bank of New York, as Indenture Trustee and Ohio Edison Company, as Lessee. (1994 Form 10-K, Exhibit 10-118.)
(E)10-101	Facility Lease dated as of September 15, 1987, between The First National Bank of Boston, as Owner Trustee, with Beaver Valley Two Pi Limited Partnership, Lessor, and Ohio Edison Company, Lessee. (1987 Form 10-K, Exhibit 28-3.)
(E)10-102	Amendment No. 1 dated as of February 1, 1988, to Facility Lease dated as of September 15, 1987, between The First National Bank of Boston, as Owner Trustee, with Beaver Valley Two Pi Limited Partnership, Lessor, and Ohio Edison Company, Lessee. (1987 Form 10-K, Exhibit 28-4.)
(E)10-103	Amendment No. 2 dated as of November 5, 1992, to Facility Lease dated as of September 15, 1987, as amended, between The First National Bank of Boston, as Owner Trustee, with Beaver Valley Two Pi Limited Partnership, as Owner Participant, and Ohio Edison Company, as Lessee. (1992 Form 10-K, Exhibit 10-103.)
(E)10-104	Amendment No. 3 dated as of September 30, 1994 to Facility Lease dated as of September 15, 1987, as amended, between The First National Bank of Boston, as Owner Trustee, with Beaver Valley Two Pi Limited Partnership, as Owner Participant, and Ohio Edison Company, as Lessee. (1994 Form 10-K, Exhibit 10-122.)
(E)10-105	Ground Lease and Easement Agreement dated as of September 15, 1987, between Ohio Edison Company, Ground Lessor, and The First National Bank of Boston, as Owner Trustee under a Trust Agreement, dated as of September 15, 1987, with Beaver Valley Two Pi Limited Partnership, Tenant. (1987 Form 10-K, Exhibit 28-5.)
(E)10-106	Trust Agreement dated as of September 15, 1987, between Beaver Valley Two Pi Limited Partnership, as Owner Participant, and The First National Bank of Boston. (1987 Form 10-K, Exhibit 28-6.)
(E)10-107	Trust Indenture, Mortgage, Security Agreement and Assignment of Facility Lease dated as of September 15, 1987, between The First National Bank of Boston, as Owner Trustee under a Trust Agreement dated as of September 15, 1987, with Beaver Valley Two Pi Limited Partnership, and Irving Trust Company, as Indenture Trustee. (1987 Form 10-K, Exhibit 28-7.)
(E)10-108	Supplemental Indenture No. 1 dated as of February 1, 1988 to Trust Indenture, Mortgage, Security Agreement and Assignment of Facility Lease dated as of September 15, 1987 between The First National Bank of Boston, as Owner Trustee under a Trust Agreement dated as of September 15, 1987 with Beaver Valley Two Pi Limited Partnership and Irving Trust Company, as Indenture Trustee. (1987 Form 10-K, Exhibit 28-8.)
(E)10-109	Tax Indemnification Agreement dated as of September 15, 1987, between Beaver Valley Two Pi Inc. and PARock Limited Partnership as General Partners and Ohio Edison Company, as Lessee. (1987 Form 10-K, Exhibit 28-9.)

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(E)10-110	Amendment No. 1 dated as of November 5, 1992 to Tax Indemnification Agreement dated as of September 15, 1987, between Beaver Valley Two Pi Inc. and PARock Limited Partnership as General Partners and Ohio Edison Company, as Lessee. (1994 Form 10-K, Exhibit 10-128.)
(E)10-111	Amendment No. 2 dated as of September 30, 1994 to Tax Indemnification Agreement dated as of September 15, 1987, between Beaver Valley Two Pi Inc. and PARock Limited Partnership as General Partners and Ohio Edison Company, as Lessee. (1994 Form 10-K, Exhibit 10-129.)
(E)10-112	Tax Indemnification Agreement dated as of September 15, 1987, between HG Power Plant, Inc., as Limited Partner and Ohio Edison Company, as Lessee. (1987 Form 10-K, Exhibit 28-10.)
(E)10-113	Amendment No. 1 dated as of November 5, 1992 to Tax Indemnification Agreement dated as of September 15, 1987, between HG Power Plant, Inc., as Limited Partner and Ohio Edison Company, as Lessee. (1994 Form 10-K, Exhibit 10-131.)
(E)10-114	Amendment No. 2 dated as of September 30, 1994 to Tax Indemnification Agreement dated as of September 15, 1987, between HG Power Plant, Inc., as Limited Partner and Ohio Edison Company, as Lessee. (1994 Form 10-K, Exhibit 10-132.)
(E)10-115	Assignment, Assumption and Further Agreement dated as of September 15, 1987, among The First National Bank of Boston, as Owner Trustee under a Trust Agreement, dated as of September 15, 1987, with Beaver Valley Two Pi Limited Partnership, The Cleveland Electric Illuminating Company, Duquesne Light Company, Ohio Edison Company, Pennsylvania Power Company and Toledo Edison Company. (1987 Form 10-K, Exhibit 28-11.)
(E)10-116	Additional Support Agreement dated as of September 15, 1987, between The First National Bank of Boston, as Owner Trustee under a Trust Agreement, dated as of September 15, 1987, with Beaver Valley Two Pi Limited Partnership, and Ohio Edison Company. (1987 Form 10-K, Exhibit 28-12.)
(F)10-117	Participation Agreement dated as of September 15, 1987, among Chrysler Consortium Corporation, as Owner Participant, the Original Loan Participants listed in Schedule 1 Thereto, as Original Loan Participants, BVPS Funding Corporation as Funding Corporation, The First National Bank of Boston, as Owner Trustee, Irving Trust Company, as Indenture Trustee and Ohio Edison Company, as Lessee. (1987 Form 10-K, Exhibit 28-13.)
(F)10-118	Amendment No. 1 dated as of February 1, 1988, to Participation Agreement dated as of September 15, 1987, among Chrysler Consortium Corporation, as Owner Participant, the Original Loan Participants listed in Schedule 1 Thereto, as Original Loan Participants, BVPS Funding Corporation, as Funding Corporation, The First National Bank of Boston, as Owner Trustee, Irving Trust Company, as Indenture Trustee, and Ohio Edison Company, as Lessee. (1987 Form 10-K, Exhibit 28-14.)
(F)10-119	Amendment No. 3 dated as of March 16, 1988 to Participation Agreement dated as of September 15, 1987, as amended, among Chrysler Consortium Corporation, as Owner Participant, BVPS Funding Corporation, The First National Bank of Boston, as Owner Trustee, Irving Trust Company, as Indenture Trustee, and Ohio Edison Company, as Lessee. (1992 Form 10-K, Exhibit 10-114.)
(F)10-120	Amendment No. 4 dated as of November 5, 1992 to Participation Agreement dated as of September 15, 1987, as amended, among Chrysler Consortium Corporation, as Owner Participant, BVPS Funding Corporation, BVPS II Funding Corporation, The First National Bank of Boston, as Owner Trustee, The Bank of New York, as Indenture Trustee and Ohio Edison Company, as Lessee. (1992 Form 10-K, Exhibit 10-115.)
(F)10-121	Amendment No. 5 dated as of January 12, 1993 to Participation Agreement dated as of September 15, 1987, as amended, among Chrysler Consortium Corporation, as Owner Participant, BVPS Funding Corporation, BVPS II Funding Corporation, The First National Bank of Boston, as Owner Trustee, The Bank of New York, as Indenture Trustee and Ohio Edison Company, as Lessee. (1994 Form 10-K, Exhibit 10-139.)

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(F)10-122	Amendment No. 6 dated as of September 30, 1994 to Participation Agreement dated as of September 15, 1987, as amended, among Chrysler Consortium Corporation, as Owner Participant, BVPS Funding Corporation, BVPS II Funding Corporation, The First National Bank of Boston, as Owner Trustee, The Bank of New York, as Indenture Trustee and Ohio Edison Company, as Lessee. (1994 Form 10-K, Exhibit 10-140.)
(F)10-123	Facility Lease dated as of September 15, 1987, between The First National Bank of Boston, as Owner Trustee, with Chrysler Consortium Corporation, Lessor, and Ohio Edison Company, as Lessee. (1987 Form 10-K, Exhibit 28-15.)
(F)10-124	Amendment No. 1 dated as of February 1, 1988, to Facility Lease dated as of September 15, 1987, between The First National Bank of Boston, as Owner Trustee, with Chrysler Consortium Corporation, Lessor, and Ohio Edison Company, Lessee. (1987 Form 10-K, Exhibit 28-16.)
(F)10-125	Amendment No. 2 dated as of November 5, 1992 to Facility Lease dated as of September 15, 1987, as amended, between The First National Bank of Boston, as Owner Trustee, with Chrysler Consortium Corporation, as Owner Participant, and Ohio Edison Company, as Lessee. (1992 Form 10-K, Exhibit 10-118.)
(F)10-126	Amendment No. 3 dated as of January 12, 1993 to Facility Lease dated as of September 15, 1987, as amended, between The First National Bank of Boston, as Owner Trustee, with Chrysler Consortium Corporation, as Owner Participant, and Ohio Edison Company, as Lessee. (1992 Form 10-K, Exhibit 10-119.)
(F)10-127	Amendment No. 4 dated as of September 30, 1994 to Facility Lease dated as of September 15, 1987, as amended, between The First National Bank of Boston, as Owner Trustee, with Chrysler Consortium Corporation, as Owner Participant, and Ohio Edison Company, as Lessee. (1994 Form 10-K, Exhibit 10-145.)
(F)10-128	Ground Lease and Easement Agreement dated as of September 15, 1987, between Ohio Edison Company, Ground Lessor, and The First National Bank of Boston, as Owner Trustee under a Trust Agreement, dated as of September 15, 1987, with Chrysler Consortium Corporation, Tenant. (1987 Form 10-K, Exhibit 28-17.)
(F)10-129	Trust Agreement dated as of September 15, 1987, between Chrysler Consortium Corporation, as Owner Participant, and The First National Bank of Boston. (1987 Form 10-K, Exhibit 28-18.)
(F)10-130	Trust Indenture, Mortgage, Security Agreement and Assignment of Facility Lease dated as of September 15, 1987, between The First National Bank of Boston, as Owner Trustee under a Trust Agreement, dated as of September 15, 1987, with Chrysler Consortium Corporation and Irving Trust Company, as Indenture Trustee. (1987 Form 10-K, Exhibit 28-19.)
(F)10-131	Supplemental Indenture No. 1 dated as of February 1, 1988 to Trust Indenture, Mortgage, Security Agreement and Assignment of Facility Lease dated as of September 15, 1987 between The First National Bank of Boston, as Owner Trustee under a Trust Agreement dated as of September 15, 1987 with Chrysler Consortium Corporation and Irving Trust Company, as Indenture Trustee. (1987 Form 10-K, Exhibit 28-20.)
(F)10-132	Tax Indemnification Agreement dated as of September 15, 1987, between Chrysler Consortium Corporation, as Owner Participant, and Ohio Edison Company, Lessee. (1987 Form 10-K, Exhibit 28-21.)
(F)10-133	Amendment No. 1 dated as of November 5, 1992 to Tax Indemnification Agreement dated as of September 15, 1987, between Chrysler Consortium Corporation, as Owner Participant, and Ohio Edison Company, as Lessee. (1994 Form 10-K, Exhibit 10-151.)
(F)10-134	Amendment No. 2 dated as of January 12, 1993 to Tax Indemnification Agreement dated as of September 15, 1987, between Chrysler Consortium Corporation, as Owner Participant, and Ohio Edison Company, as Lessee. (1994 Form 10-K, Exhibit 10-152.)
(F)10-135	Amendment No. 3 dated as of September 30, 1994 to Tax Indemnification Agreement dated as of September 15, 1987, between Chrysler Consortium Corporation, as Owner Participant, and Ohio Edison Company, as Lessee. (1994 Form 10-K, Exhibit 10-153.)

Exhibit Number	
(F)10-136	Assignment, Assumption and Further Agreement dated as of September 15, 1987, among The First National Bank of Boston, as Owner Trustee under a Trust Agreement, dated as of September 15, 1987, with Chrysler Consortium Corporation, The Cleveland Electric Illuminating Company, Duquesne Light Company, Ohio Edison Company, Pennsylvania Power Company, and Toledo Edison Company. (1987 Form 10-K, Exhibit 28-22.)
(F)10-137	Additional Support Agreement dated as of September 15, 1987, between The First National Bank of Boston, as Owner Trustee under a Trust Agreement, dated as of September 15, 1987, with Chrysler Consortium Corporation, and Ohio Edison Company. (1987 Form 10-K, Exhibit 28-23.)
10-138	Operating Agreement dated March 10, 1987 with respect to Perry Unit No. 1 between the CAPCO Companies. (1987 Form 10-K, Exhibit 28-24.)
10-139	Operating Agreement for Bruce Mansfield Units Nos. 1, 2 and 3 dated as of June 1, 1976, and executed on September 15, 1987, by and between the CAPCO Companies. (1987 Form 10-K, Exhibit 28-25.)
10-140	Operating Agreement for W. H. Sammis Unit No. 7 dated as of September 1, 1971 by and between the CAPCO Companies. (1987 Form 10-K, Exhibit 28-26.)
10-141	OE-APS Power Interchange Agreement dated March 18, 1987, by and among Ohio Edison Company and Pennsylvania Power Company, and Monongahela Power Company and West Penn Power Company and The Potomac Edison Company. (1987 Form 10-K, Exhibit 28-27.)
10-142	OE-PEPCO Power Supply Agreement dated March 18, 1987, by and among Ohio Edison Company and Pennsylvania Power Company and Potomac Electric Power Company. (1987 Form 10-K, Exhibit 28-28.)
10-143	Supplement No. 1 dated as of April 28, 1987, to the OE-PEPCO Power Supply Agreement dated March 18, 1987, by and among Ohio Edison Company, Pennsylvania Power Company, and Potomac Electric Power Company. (1987 Form 10-K, Exhibit 28-29.)
10-144	APS-PEPCO Power Resale Agreement dated March 18, 1987, by and among Monongahela Power Company, West Penn Power Company, and The Potomac Edison Company and Potomac Electric Power Company. (1987 Form 10-K, Exhibit 28-30.)
(A)10-145	Electric Power Supply Agreement, between the Cleveland Electric Illuminating Company, Ohio Edison Company, Pennsylvania Power Company, the Toledo Edison Company, and First Energy Solutions Corp. (f.k.a. FirstEnergy Services Corp.), dated January 1, 2001.
(A)10-146	Revised Electric Power Supply Agreement, between FirstEnergy Solutions Corp., the Cleveland Electric Illuminating Company, Ohio Edison Company, Pennsylvania Power Company, and the Toledo Edison Company, dated October 1, 2003.
(A)10-147	Master Facility Lease, between Ohio Edison Company, Pennsylvania Power Company, the Cleveland Electric Illuminating Company, the Toledo Edison Company, and FirstEnergy Generation Corp., dated January 1, 2001.
(A)10-148	$125,000,000 Three-Year Credit Agreement dated as of October 23, 2003 by and among Ohio Edison Company, Citibank, N.A., as Administrative Agent, and the other lenders named therein.
(A)10-149	$250,000,000 Credit Agreement dated as of May 12, 2003 by and among Ohio Edison Company, JPMorgan Chase Bank, as Administrative Agent, and the other lenders named therein.
(A)12.2	Consolidated fixed charge ratios.
(A)13.1	OE 2004 Annual Report to Stockholders (Only those portions expressly incorporated by reference in this Form 10-K are to be deemed "filed" with the SEC.)
(A)21.1	List of Subsidiaries of the Registrant at December 31, 2004.

Exhibit
Number

(A)23.1 Consent of Independent Registered Public Accounting Firm.

(A) Provided herein in electronic format as an exhibit.

(B) Pursuant to paragraph (b)(4)(iii)(A) of Item 601 of Regulation S-K, OE has not filed as an exhibit to this Form 10-K any instrument with respect to long-term debt if the total amount of securities authorized thereunder does not exceed 10% of the total assets of OE and its subsidiaries on a consolidated basis, but hereby agrees to furnish to the SEC on request any such instruments.

(C) Management contract or compensatory plan contract or arrangement filed pursuant to Item 601 of Regulation S-K.

(D) Substantially similar documents have been entered into relating to three additional Owner Participants.

(E) Substantially similar documents have been entered into relating to five additional Owner Participants.

(F) Substantially similar documents have been entered into relating to two additional Owner Participants.

Note: Reports of OE on Forms 10-Q and 10-K are on file with the SEC under number 1-2578.

Pursuant to Rule 14a – 3 (10) of the Securities Exchange Act of 1934, the Company will furnish any exhibit in this Report upon the payment of the Company's expenses in furnishing such exhibit.

3. Exhibits – Penn

3-1 Amended and Restated Articles of Incorporation, as amended March 15, 2002. (2001 Form 10-K, Exhibit 3-1)

3-2 Amended and Restated By-Laws of Penn, as amended March 15, 2002. (2001 Form 10-K, Exhibit 3-2)

4-1 Indenture dated as of November 1, 1945, between Penn and The First National Bank of the City of New York (now Citibank, N.A.), as Trustee, as supplemented and amended by Supplemental Indentures dated as of May 1, 1948, March 1, 1950, February 1, 1952, October 1, 1957, September 1, 1962, June 1, 1963, June 1, 1969, May 1, 1970, April 1, 1971, October 1, 1971, May 1, 1972, December 1, 1974, October 1, 1975, September 1, 1976, April 15, 1978, June 28, 1979, January 1, 1980, June 1, 1981, January 14, 1982, August 1, 1982, December 15, 1982, December 1, 1983, September 6, 1984, December 1, 1984, May 30, 1985, October 29, 1985, August 1, 1987, May 1, 1988, November 1, 1989, December 1, 1990, September 1, 1991, May 1, 1992, July 15, 1992, August 1, 1992, and May 1, 1993, July 1, 1993, August 31, 1993, September 1, 1993, September 15, 1993, October 1, 1993, November 1, 1993, and August 1, 1994. (Physically filed and designated as Exhibits 2(b)(1)-1 through 2(b)(1)-15 in Registration Statement File No. 2-60837; as Exhibits 2(b)(2), 2(b)(3), and 2(b)(4) in Registration Statement File No. 2-68906; as Exhibit 4-2 in Form 10-K for 1981 File No. 1-3491; as Exhibit 19-1 in Form 10-K for 1982 File No. 1-3491; as Exhibit 19-1 in Form 10-K for 1983 File No. 1-3491; as Exhibit 19-1 in Form 10-K for 1984 File No. 1-3491; as Exhibit 19-1 in Form 10-K for 1985 File No. 1-3491; as Exhibit 19-1 in Form 10-K for 1987 File No. 1-3491; as Exhibit 19-1 in Form 10-K for 1988 File No. 1-3491; as Exhibit 19 in Form 10-K for 1989 File No. 1-3491; as Exhibit 19 in Form 10-K for 1990 File No. 1-3491; as Exhibit 19 in Form 10-K for 1991 File No. 1-3491; as Exhibit 19-1 in Form 10-K for 1992 File No. 1-3491; as Exhibit 4-2 in Form 10-K for 1993 File No. 1-3491; and as Exhibit 4-2 in Form 10-K for 1994 File No. 1-3491.)

4-2 Supplemental Indenture dated as of September 1, 1995, between Penn and Citibank, N.A., as Trustee. (1995 Form 10-K, Exhibit 4-2.)

4-3 Supplemental Indenture dated as of June 1, 1997, between Penn and Citibank, N.A., as Trustee. (1997 Form 10-K, Exhibit 4-3.)

Exhibit Number	
4-4	Supplemental Indenture dated as of June 1, 1998, between Penn and Citibank, N. A., as Trustee. (1998 Form 10-K, Exhibit 4-4.)
4-5	Supplemental Indenture dated as of September 29, 1999, between Penn and Citibank, N.A., as Trustee. (1999 Form 10-K, Exhibit 4-5.)
4-6	Supplemental Indenture dated as of November 15, 1999, between Penn and Citibank, N.A., as Trustee. (1999 Form 10-K, Exhibit 4-6.)
4-7	Supplemental Indenture dated as of June 1, 2001. (2001 Form 10-K, Exhibit 4-7)
(A)4-8	Supplemental Indenture dated as of December 1, 2004.
10-1	Administration Agreement between the CAPCO Group dated as of September 14, 1967. (Registration Statement of Ohio Edison Company, File No. 2-43102, Exhibit 5(c)(2).)
10-2	Amendment No. 1 dated January 4, 1974 to Administration Agreement between the CAPCO Group dated as of September 14, 1967. (Registration Statement No. 2-68906, Exhibit 5 (c)(3).)
10-3	Transmission Facilities Agreement between the CAPCO Group dated as of September 14, 1967. (Registration Statement of Ohio Edison Company, File No. 2-43102, Exhibit 5 (c)(3).)
10-4	Amendment No. 1 dated as of January 1, 1993 to Transmission Facilities Agreement between the CAPCO Group dated as of September 14, 1967. (1993 Form 10-K, Exhibit 10-4, Ohio Edison Company.)
10-5	Agreement for the Termination or Construction of Certain Agreements effective September 1, 1980 among the CAPCO Group. (Registration Statement No. 2-68906, Exhibit 10-4.)
10-6	Amendment dated as of December 23, 1993 to Agreement for the Termination or Construction of Certain Agreements effective September 1, 1980 among the CAPCO Group. (1993 Form 10-K, Exhibit 10-6, Ohio Edison Company.)
10-7	CAPCO Basic Operating Agreement, as amended September 1, 1980. (Registration Statement No. 2-68906, as Exhibit 10-5.)
10-8	Amendment No. 1 dated August 1, 1981 and Amendment No. 2 dated September 1, 1982, to CAPCO Basic Operating Agreement as amended September 1, 1980. (September 30, 1981 Form 10-Q, Exhibit 20-1 and 1982 Form 10-K, Exhibit 19-3, File No. 1-2578, of Ohio Edison Company.)
10-9	Amendment No. 3 dated as of July 1, 1984, to CAPCO Basic Operating Agreement as amended September 1, 1980. (1985 Form 10-K, Exhibit 10-7, File No. 1-2578, of Ohio Edison Company.)
10-10	Basic Operating Agreement between the CAPCO Companies as amended October 1, 1991. (1991 Form 10-K, Exhibit 10-8, File No. 1-2578, of Ohio Edison Company.)
10-11	Basic Operating Agreement between the CAPCO Companies as amended January 1, 1993. (1993 Form 10-K, Exhibit 10-11, Ohio Edison.)
10-12	Memorandum of Agreement effective as of September 1, 1980, among the CAPCO Group. (1991 Form 10-K, Exhibit 19-2, Ohio Edison Company.)
10-13	Operating Agreement for Beaver Valley Power Station Units Nos. 1 and 2 as Amended and Restated September 15, 1987, by and between the CAPCO Companies. (1987 Form 10-K, Exhibit 10-15, File No. 1-2578, of Ohio Edison Company.)
10-14	Construction Agreement with respect to Perry Plant between the CAPCO Group dated as of July 22, 1974. (Registration Statement of Toledo Edison Company, File No. 2-52251, as Exhibit 5 (yy).)
10-15	Memorandum of Understanding dated as of March 31, 1985, among the CAPCO Companies. (1985 Form 10-K, Exhibit 10-35, File No. 1-2578, Ohio Edison Company.)

Exhibit Number	
(B)10-16	Ohio Edison System Executive Supplemental Life Insurance Plan. (1995 Form 10-K, Exhibit 10-44, File No. 1-2578, Ohio Edison Company.)
(B)10-17	Ohio Edison System Executive Incentive Compensation Plan. (1995 Form 10-K, Exhibit 10-45, File No. 1-2578, Ohio Edison Company.)
(B)10-18	Ohio Edison System Restated and Amended Executive Deferred Compensation Plan. (1995 Form 10-K, Exhibit 10-46, File No. 1-2578, Ohio Edison Company.)
(B)10-19	Ohio Edison System Restated and Amended Supplemental Executive Retirement Plan. (1995 Form 10-K, Exhibit 10-47, File No. 1-2578, Ohio Edison Company.)
10-20	Operating Agreement for Perry Unit No. 1 dated March 10, 1987, by and between the CAPCO Companies. (1987 Form 10-K, Exhibit 28-24, File No. 1-2578, Ohio Edison Company.)
10-21	Operating Agreement for Bruce Mansfield Units Nos. 1, 2 and 3 dated as of June 1, 1976, and executed on September 15, 1987, by and between the CAPCO Companies. (1987 Form 10-K, Exhibit 28-25, File No. 1-2578, Ohio Edison Company.)
10-22	Operating Agreement for W. H. Sammis Unit No. 7 dated as of September 1, 1971, by and between the CAPCO Companies. (1987 Form 10-K, Exhibit 28-26, File No. 1-2578, Ohio Edison Company.)
10-23	OE-APS Power Interchange Agreement dated March 18, 1987, by and among Ohio Edison Company and Pennsylvania Power Company, and Monongahela Power Company and West Penn Power Company and The Potomac Edison Company. (1987 Form 10-K, Exhibit 28-27, File No. 1-2578, of Ohio Edison Company.)
10-24	OE-PEPCO Power Supply Agreement dated March 18, 1987, by and among Ohio Edison Company and Pennsylvania Power Company and Potomac Electric Power Company. (1987 Form 10-K, Exhibit 28-28, File No. 1-2578, of Ohio Edison Company.)
10-25	Supplement No. 1 dated as of April 28, 1987, to the OE-PEPCO Power Supply Agreement dated March 18, 1987, by and among Ohio Edison Company, Pennsylvania Power Company and Potomac Electric Power Company. (1987 Form 10-K, Exhibit 28-29, File No. 1-2578, of Ohio Edison Company.)
10-26	APS-PEPCO Power Resale Agreement dated March 18, 1987, by and among Monongahela Power Company, West Penn Power Company, and The Potomac Edison Company and Potomac Electric Power Company. (1987 Form 10-K, Exhibit 28-30, File No. 1-2578, of Ohio Edison Company.)
10-27	Pennsylvania Power Company Master Decommissioning Trust Agreement for Beaver Valley Power Station and Perry Nuclear Power Plant dated as of April 21, 1995. (Quarter ended June 30, 1995 Form 10-Q, Exhibit 10, File No. 1-3491.)
10-28	Nuclear Fuel Lease dated as of March 31, 1989, between OES Fuel, Incorporated, as Lessor, and Pennsylvania Power Company, as Lessee. (1989 Form 10-K, Exhibit 10-39, File No. 1-3491.)
10-29	Electric Power Supply Agreement, between the Cleveland Electric Illuminating Company, Ohio Edison Company, Pennsylvania Power Company, the Toledo Edison Company, and First Energy Solutions Corp. (f.k.a. FirstEnergy Services Corp.), dated January 1, 2001. (Filed as Ohio Edison Exhibit 10-145 in 2004 Form 10-K)
10-30	Revised Electric Power Supply Agreement, between FirstEnergy Solutions Corp., the Cleveland Electric Illuminating Company, Ohio Edison Company, Pennsylvania Power Company, and the Toledo Edison Company, dated October 1, 2003. (Filed as Ohio Edison Exhibit 10-146 in 2004 Form 10-K)

Exhibit
Number

10-31	Master Facility Lease, between Ohio Edison Company, Pennsylvania Power Company, the Cleveland Electric Illuminating Company, the Toledo Edison Company, and FirstEnergy Generation Corp., dated January 1, 2001. (Filed as Ohio Edison Exhibit 10-147 in 2004 Form 10-K)
(A)12.5	Fixed Charge Ratios
(A)13.4	Penn 2004 Annual Report to Stockholders. (Only those portions expressly incorporated by reference in this Form 10-K are to be deemed "filed" with the Securities and Exchange Commission.)
(A)21.4	List of Subsidiaries of the Registrant at December 31, 2004.
(A)23.2	Consent of Independent Registered Public Accounting Firm.
(A)	Provided herein in electronic format as an exhibit.
(B)	Pursuant to paragraph (b)(4)(iii)(A) of Item 601 of Regulation S-K, Penn has not filed as an exhibit to this Form 10-K any instrument with respect to long-term debt if the total amount of securities authorized thereunder does not exceed 10% of the total assets of Penn, but hereby agrees to furnish to the Commission on request any such instruments.
(C)	Management contract or compensatory plan contract or arrangement filed pursuant to Item 601 of Regulation S-K.

Pursuant to Rule 14a-3(10) of the Securities Exchange Act of 1934, the Company will furnish any exhibit in this Report upon the payment of the Company's expenses in furnishing such exhibit.

3. Exhibits – Common Exhibits to CEI and TE

Exhibit
Number

2(a)	Agreement and Plan of Merger between Ohio Edison and Centerior Energy dated as of September 13, 1996 (Exhibit (2)-1, Form S-4 File No. 333-21011, filed by FirstEnergy).
2(b)	Merger Agreement by and among Centerior Acquisition Corp., FirstEnergy and Centerior (Exhibit (2)-3, Form S-4 File No. 333-21011, filed by FirstEnergy).
4(a)	Rights Agreement (Exhibit 4, June 25, 1996 Form 8-K, File Nos. 1-9130, 1-2323 and 1-3583).
4(b)(1)	Form of Note Indenture between Cleveland Electric, Toledo Edison and The Chase Manhattan Bank, as Trustee dated as of June 13, 1997 (Exhibit 4(c), Form S-4 File No. 333-35931, filed by Cleveland Electric and Toledo Edison).
4(b)(2)	Form of First Supplemental Note Indenture between Cleveland Electric, Toledo Edison and The Chase Manhattan Bank, as Trustee dated as of June 13, 1997 (Exhibit 4(d), Form S-4 File No. 333-35931, filed by Cleveland Electric and Toledo Edison).
10b(1)(a)	CAPCO Administration Agreement dated November 1, 1971, as of September 14, 1967, among the CAPCO Group members regarding the organization and procedures for implementing the objectives of the CAPCO Group (Exhibit 5(p), Amendment No. 1, File No. 2-42230, filed by Cleveland Electric).
10b(1)(b)	Amendment No. 1, dated January 4, 1974, to CAPCO Administration Agreement among the CAPCO Group members (Exhibit 5(c)(3), File No. 2-68906, filed by Ohio Edison).
10b(2)	CAPCO Transmission Facilities Agreement dated November 1, 1971, as of September 14, 1967, among the CAPCO Group members regarding the installation, operation and maintenance of transmission facilities to carry out the objectives of the CAPCO Group (Exhibit 5(q), Amendment No. 1, File No. 2-42230, filed by Cleveland Electric).

Exhibit Number	
10b(2)(1)	Amendment No. 1 to CAPCO Transmission Facilities Agreement, dated December 23, 1993 and effective as of January 1, 1993, among the CAPCO Group members regarding requirements for payment of invoices at specified times, for payment of interest on non-timely paid invoices, for restricting adjustment of invoices after a four-year period, and for revising the method for computing the Investment Responsibility charge for use of a member's transmission facilities (Exhibit 10b(2)(1), 1993 Form 10-K, File Nos. 1-9130, 1-2323 and 1-3583).
10b(3)	CAPCO Basic Operating Agreement As Amended January 1, 1993 among the CAPCO Group members regarding coordinated operation of the members' systems (Exhibit 10b(3), 1993 Form 10-K, File Nos. 1-9130, 1-2323 and 1-3583).
10b(4)	Agreement for the Termination or Construction of Certain Agreement By and Among the CAPCO Group members, dated December 23, 1993 and effective as of September 1, 1980 (Exhibit 10b(4), 1993 Form 10-K, File Nos. 1-9130, 1-2323 and 1-3583).
10b(5)	Construction Agreement, dated July 22, 1974, among the CAPCO Group members and relating to the Perry Nuclear Plant (Exhibit 5 (yy), File No. 2-52251, filed by Toledo Edison).
10b(6)	Contract, dated as of December 5, 1975, among the CAPCO Group members for the construction of Beaver Valley Unit No. 2 (Exhibit 5 (g), File No. 2-52996, filed by Cleveland Electric).
10b(7)	Amendment No. 1, dated May 1, 1977, to Contract, dated as of December 5, 1975, among the CAPCO Group members for the construction of Beaver Valley Unit No. 2 (Exhibit 5(d)(4), File No. 2-60109, filed by Ohio Edison).
10d(1)(a)	Form of Collateral Trust Indenture among CTC Beaver Valley Funding Corporation, Cleveland Electric, Toledo Edison and Irving Trust Company, as Trustee (Exhibit 4(a), File No. 33-18755, filed by Cleveland Electric and Toledo Edison).
10d(1)(b)	Form of Supplemental Indenture to Collateral Trust Indenture constituting Exhibit 10d(1)(a) above, including form of Secured Lease Obligation bond (Exhibit 4(b), File No. 33-18755, filed by Cleveland Electric and Toledo Edison).
10d(1)(c)	Form of Collateral Trust Indenture among Beaver Valley II Funding Corporation, The Cleveland Electric Illuminating Company and The Toledo Edison Company and The Bank of New York, as Trustee (Exhibit (4)(a), File No. 33-46665, filed by Cleveland Electric and Toledo Edison).
10d(1)(d)	Form of Supplemental Indenture to Collateral Trust Indenture constituting Exhibit 10d(1)(c) above, including form of Secured Lease Obligation Bond (Exhibit (4)(b), File No. 33-46665, filed by Cleveland Electric and Toledo Edison).
10d(2)(a)	Form of Collateral Trust Indenture among CTC Mansfield Funding Corporation, Cleveland Electric, Toledo Edison and IBJ Schroder Bank & Trust Company, as Trustee (Exhibit 4(a), File No. 33-20128, filed by Cleveland Electric and Toledo Edison).
10d(2)(b)	Form of Supplemental Indenture to Collateral Trust Indenture constituting Exhibit 10d(2)(a) above, including forms of Secured Lease Obligation bonds (Exhibit 4(b), File No. 33-20128, filed by Cleveland Electric and Toledo Edison).
10d(3)(a)	Form of Facility Lease dated as of September 15, 1987 between The First National Bank of Boston, as Owner Trustee under a Trust Agreement dated as of September 15, 1987 with the limited partnership Owner Participant named therein, Lessor, and Cleveland Electric and Toledo Edison, Lessee (Exhibit 4(c), File No. 33-18755, filed by Cleveland Electric and Toledo Edison).
10d(3)(b)	Form of Amendment No. 1 to Facility Lease constituting Exhibit 10d(3)(a) above (Exhibit 4(e), File No. 33-18755, filed by Cleveland Electric and Toledo Edison).
10d(4)(a)	Form of Facility Lease dated as of September 15, 1987 between The First National Bank of Boston, as Owner Trustee under a Trust Agreement dated as of September 15, 1987 with the corporate Owner Participant named therein, Lessor, and Cleveland Electric and Toledo Edison, Lessees (Exhibit 4(d), File No. 33-18755, filed by Cleveland Electric and Toledo Edison).

Exhibit Number	
10d(4)(b)	Form of Amendment No. 1 to Facility Lease constituting Exhibit 10d(4)(a) above (Exhibit 4(f), File No. 33-18755, filed by Cleveland Electric and Toledo Edison).
10d(5)(a)	Form of Facility Lease dated as of September 30, 1987 between Meridian Trust Company, as Owner Trustee under a Trust Agreement dated as of September 30, 1987 with the Owner Participant named therein, Lessor, and Cleveland Electric and Toledo Edison, Lessees (Exhibit 4(c), File No. 33-20128, filed by Cleveland Electric and Toledo Edison).
10d(5)(b)	Form of Amendment No. 1 to the Facility Lease constituting Exhibit 10d(5)(a) above (Exhibit 4(f), File No. 33-20128, filed by Cleveland Electric and Toledo Edison).
10d(6)(a)	Form of Participation Agreement dated as of September 15, 1987 among the limited partnership Owner Participant named therein, the Original Loan Participants listed in Schedule 1 thereto, as Original Loan Participants, CTC Beaver Valley Fund Corporation, as Funding Corporation, The First National Bank of Boston, as Owner Trustee, Irving Trust Company, as Indenture Trustee, and Cleveland Electric and Toledo Edison, as Lessees (Exhibit 28(a), File No. 33-18755, filed by Cleveland Electric And Toledo Edison).
10d(6)(b)	Form of Amendment No. 1 to Participation Agreement constituting Exhibit 10d(6)(a) above (Exhibit 28(c), File No. 33-18755, filed by Cleveland Electric and Toledo Edison).
10d(7)(a)	Form of Participation Agreement dated as of September 15, 1987 among the corporate Owner Participant named therein, the Original Loan Participants listed in Schedule 1 thereto, as Owner Loan Participants, CTC Beaver Valley Funding Corporation, as Funding Corporation, The First National Bank of Boston, as Owner Trustee, Irving Trust Company, as Indenture Trustee, and Cleveland Electric and Toledo Edison, as Lessees (Exhibit 28(b), File No. 33-18755, filed by Cleveland Electric and Toledo Edison).
10d(7)(b)	Form of Amendment No. 1 to Participation Agreement constituting Exhibit 10d(7)(a) above (Exhibit 28(d), File No. 33-18755, filed by Cleveland Electric and Toledo Edison).
10d(8)(a)	Form of Participation Agreement dated as of September 30, 1987 among the Owner Participant named therein, the Original Loan Participants listed in Schedule II thereto, as Owner Loan Participants, CTC Mansfield Funding Corporation, Meridian Trust Company, as Owner Trustee, IBJ Schroder Bank & Trust Company, as Indenture Trustee, and Cleveland Electric and Toledo Edison, as Lessees (Exhibit 28(a), File No. 33-0128, filed by Cleveland Electric and Toledo Edison).
10d(8)(b)	Form of Amendment No. 1 to the Participation Agreement constituting Exhibit 10d(8)(a) above (Exhibit 28(b), File No. 33-20128, filed by Cleveland Electric and Toledo Edison).
10d(9)	Form of Ground Lease dated as of September 15, 1987 between Toledo Edison, Ground Lessor, and The First National Bank of Boston, as Owner Trustee under a Trust Agreement dated as of September 15, 1987, with the Owner Participant named therein, Tenant (Exhibit 28(e), File No. 33-18755, filed by Cleveland Electric and Toledo Edison).
10d(10)	Form of Site Lease dated as of September 30, 1987 between Toledo Edison, Lessor, and Meridian Trust Company, as Owner Trustee under a Trust Agreement dated as of September 30, 1987 with the Owner Participant named therein, Tenant (Exhibit 28(c), File No. 33-20128, filed by Cleveland Electric and Toledo Edison).
10d(11)	Form of Site Lease dated as of September 30, 1987 between Cleveland Electric, Lessor, and Meridian Trust Company, as Owner Trustee under a Trust Agreement dated as of September 30, 1987 with the Owner Participant named therein, Tenant (Exhibit 28(d), File No. 33-20128, filed by Cleveland Electric and Toledo Edison).
10d(12)	Form of Amendment No. 1 to the Site Leases constituting Exhibits 10d(10) and 10d(11) above (Exhibit 4(f), File No. 33-20128, filed by Cleveland Electric and Toledo Edison).

Exhibit Number	
10d(13)	Form of Assignment, Assumption and Further Agreement dated as of September 15, 1987 among The First National Bank of Boston, as Owner Trustee under a Trust Agreement dated as of September 15, 1987 with the Owner Participant named therein, Cleveland Electric, Duquesne, Ohio Edison, Pennsylvania Power and Toledo Edison (Exhibit 28(f), File No. 33-18755, filed by Cleveland Electric and Toledo Edison).
10d(14)	Form of Additional Support Agreement dated as of September 15, 1987 between The First National Bank of Boston, as Owner Trustee under a Trust Agreement dated as of September 15, 1987 with the Owner Participant named therein, and Toledo Edison (Exhibit 28(g), File No. 33-18755, filed by Cleveland Electric and Toledo Edison).
10d(15)	Form of Support Agreement dated as of September 30, 1987 between Meridian Trust Company, as Owner Trustee under a Trust Agreement dated as of September 30, 1987 with the Owner Participant named therein, Toledo Edison, Cleveland Electric, Duquesne, Ohio Edison and Pennsylvania Power (Exhibit 28(e), File No. 33-20128, filed by Cleveland Electric and Toledo Edison).
10d(16)	Form of Indenture, Bill of Sale, Instrument of Transfer and Severance Agreement dated as of September 30, 1987 between Toledo Edison, Seller, and The First National Bank of Boston, as Owner Trustee under a Trust Agreement dated as of September 15, 1987 with the Owner Participant named therein, Buyer (Exhibit 28(h), File No. 33-18755, filed by Cleveland Electric and Toledo Edison).
10d(17)	Form of Bill of Sale, Instrument of Transfer and Severance Agreement dated as of September 30, 1987 between Toledo Edison, Seller, and Meridian Trust Company, as Owner Trustee under a Trust Agreement dated as of September 30, 1987 with the Owner Participant named therein, Buyer (Exhibit 28(f), File No. 33-20128, filed by Cleveland Electric and Toledo Edison).
10d(18)	Form of Bill of Sale, Instrument of Transfer and Severance Agreement dated as of September 30, 1987 between Cleveland Electric, Seller, and Meridian Trust Company, as Owner Trustee under a Trust Agreement dated as of September 30, 1987 with the Owner Participant named therein, Buyer (Exhibit 28(g), File No. 33-20128, filed by Cleveland Electric and Toledo Edison).
10d(19)	Forms of Refinancing Agreement, including exhibits thereto, among the Owner Participant named therein, as Owner Participant, CTC Beaver Valley Funding Corporation, as Funding Corporation, Beaver Valley II Funding Corporation, as New Funding Corporation, The Bank of New York, as Indenture Trustee, The Bank of New York, as New Collateral Trust Trustee, and The Cleveland Electric Illuminating Company and The Toledo Edison Company, as Lessees (Exhibit (28)(e)(i), File No. 33-46665, filed by Cleveland Electric and Toledo Edison).
10d(20)(a)	Form of Amendment No. 2 to Facility Lease among Citicorp Lescaman, Inc., Cleveland Electric and Toledo Edison (Exhibit 10(a), Form S-4 File No. 333-47651, filed by Cleveland Electric).
10d(20)(b)	Form of Amendment No. 3 to Facility Lease among Citicorp Lescaman, Inc., Cleveland Electric and Toledo Edison (Exhibit 10(b), Form S-4 File No. 333-47651, filed by Cleveland Electric).
10d(21)(a)	Form of Amendment No. 2 to Facility Lease among US West Financial Services, Inc., Cleveland Electric and Toledo Edison (Exhibit 10(c), Form S-4 File No. 333-47651, filed by Cleveland Electric).
10d(21)(b)	Form of Amendment No. 3 to Facility Lease among US West Financial Services, Inc., Cleveland Electric and Toledo Edison (Exhibit 10(d), Form S-4 File No. 333-47651, filed by Cleveland Electric).
10d(22)	Form of Amendment No. 2 to Facility Lease among Midwest Power Company, Cleveland Electric and Toledo Edison (Exhibit 10(e), Form S-4 File No. 333-47651, filed by Cleveland Electric).
10e(1)	Centerior Energy Corporation Equity Compensation Plan (Exhibit 99, Form S-8, File No. 33-59635).

Exhibit Number	
3. Exhibits – Cleveland Electric Illuminating (CEI)	
3a	Amended Articles of Incorporation of CEI, as amended, effective May 28, 1993 (Exhibit 3a, 1993 Form 10-K, File No. 1-2323).
3b	Regulations of CEI, dated April 29, 1981, as amended effective October 1, 1988 and April 24, 1990 (Exhibit 3b, 1990 Form 10-K, File No. 1-2323).
3c	Amended and Restated Code of Regulations, dated March 15, 2002, incorporated by reference to Exhibit 3-2, 2001 Form 10-K, File No. 1-02323.
(B) 4b(1)	Mortgage and Deed of Trust between CEI and Guaranty Trust Company of New York (now The Chase Manhattan Bank (National Association)), as Trustee, dated July 1, 1940 (Exhibit 7(a), File No. 2-4450).
	Supplemental Indentures between CEI and the Trustee, supplemental to Exhibit 4b(1), dated as follows:
4b(2)	July 1, 1940 (Exhibit 7(b), File No. 2-4450).
4b(3)	August 18, 1944 (Exhibit 4(c), File No. 2-9887).
4b(4)	December 1, 1947 (Exhibit 7(d), File No. 2-7306).
4b(5)	September 1, 1950 (Exhibit 7(c), File No. 2-8587).
4b(6)	June 1, 1951 (Exhibit 7(f), File No. 2-8994).
4b(7)	May 1, 1954 (Exhibit 4(d), File No. 2-10830).
4b(8)	March 1, 1958 (Exhibit 2(a)(4), File No. 2-13839).
4b(9)	April 1, 1959 (Exhibit 2(a)(4), File No. 2-14753).
4b(10)	December 20, 1967 (Exhibit 2(a)(4), File No. 2-30759).
4b(11)	January 15, 1969 (Exhibit 2(a)(5), File No. 2-30759).
4b(12)	November 1, 1969 (Exhibit 2(a)(4), File No. 2-35008).
4b(13)	June 1, 1970 (Exhibit 2(a)(4), File No. 2-37235).
4b(14)	November 15, 1970 (Exhibit 2(a)(4), File No. 2-38460).
4b(15)	May 1, 1974 (Exhibit 2(a)(4), File No. 2-50537).
4b(16)	April 15, 1975 (Exhibit 2(a)(4), File No. 2-52995).
4b(17)	April 16, 1975 (Exhibit 2(a)(4), File No. 2-53309).
4b(18)	May 28, 1975 (Exhibit 2(c), June 5, 1975 Form 8-A, File No. 1-2323).
4b(19)	February 1, 1976 (Exhibit 3(d)(6), 1975 Form 10 K, File No. 1-2323).
4b(20)	November 23, 1976 (Exhibit 2(a)(4), File No. 2-57375).
4b(21)	July 26, 1977 (Exhibit 2(a)(4), File No. 2-59401).
4b(22)	September 7, 1977 (Exhibit 2(a)(5), File No. 2-67221).
4b(23)	May 1, 1978 (Exhibit 2(b), June 30, 1978 Form 10-Q, File No. 1-2323).
4b(24)	September 1, 1979 (Exhibit 2(a), September 30, 1979 Form 10-Q, File No. 1-2323).
4b(25)	April 1, 1980 (Exhibit 4(a)(2), September 30, 1980 Form 10-Q, File No. 1-2323).
4b(26)	April 15, 1980 (Exhibit 4(b), September 30, 1980 Form 10-Q, File No. 1-2323).
4b(27)	May 28, 1980 (Exhibit 2(a)(4), Amendment No. 1, File No. 2-67221).
4b(28)	June 9, 1980 (Exhibit 4(d), September 30, 1980 Form 10-Q, File No. 1-2323).
4b(29)	December 1, 1980 (Exhibit 4(b)(29), 1980 Form 10-K, File No. 1-2323).
4b(30)	July 28, 1981 (Exhibit 4(a), September 30, 1981, Form 10-Q, File No. 1-2323).
4b(31)	August 1, 1981 (Exhibit 4(b), September 30, 1981, Form 10-Q, File No. 1-2323).
4b(32)	March 1, 1982 (Exhibit 4(b)(3), Amendment No. 1, File No. 2-76029).
4b(33)	July 15, 1982 (Exhibit 4(a), September 30, 1982 Form 10-Q, File No. 1-2323).
4b(34)	September 1, 1982 (Exhibit 4(a)(1), September 30, 1982 Form 10-Q, File No. 1-2323).
4b(35)	November 1, 1982 (Exhibit (a)(2), September 30, 1982 Form 10-Q, File No. 1-2323).
4b(36)	November 15, 1982 (Exhibit 4(b)(36), 1982 Form 10-K, File No. 1-2323).
4b(37)	May 24, 1983 (Exhibit 4(a), June 30, 1983 Form 10-Q, File No. 1-2323).
4b(38)	May 1, 1984 (Exhibit 4, June 30, 1984 Form 10-Q, File No. 1-2323).
4b(39)	May 23, 1984 (Exhibit 4, May 22, 1984 Form 8-K, File No. 1-2323).
4b(40)	June 27, 1984 (Exhibit 4, June 11, 1984 Form 8-K, File No. 1-2323).
4b(41)	September 4, 1984 (Exhibit 4b(41), 1984 Form 10-K, File No. 1-2323).
4b(42)	November 14, 1984 (Exhibit 4b(42), 1984 Form 10 K, File No. 1-2323).
4b(43)	November 15, 1984 (Exhibit 4b(43), 1984 Form 10-K, File No. 1-2323).
4b(44)	April 15, 1985 (Exhibit 4(a), May 8, 1985 Form 8-K, File No. 1-2323).
4b(45)	May 28, 1985 (Exhibit 4(b), May 8, 1985 Form 8-K, File No. 1-2323).

Exhibit Number	
4b(46)	August 1, 1985 (Exhibit 4, September 30, 1985 Form 10-Q, File No. 1-2323).
4b(47)	September 1, 1985 (Exhibit 4, September 30, 1985 Form 8-K, File No. 1-2323).
4b(48)	November 1, 1985 (Exhibit 4, January 31, 1986 Form 8-K, File No. 1-2323).
4b(49)	April 15, 1986 (Exhibit 4, March 31, 1986 Form 10-Q, File No. 1-2323).
4b(50)	May 14, 1986 (Exhibit 4(a), June 30, 1986 Form 10-Q, File No. 1-2323).
4b(51)	May 15, 1986 (Exhibit 4(b), June 30, 1986 Form 10-Q, File No. 1-2323).
4b(52)	February 25, 1987 (Exhibit 4b(52), 1986 Form 10-K, File No. 1-2323).
4b(53)	October 15, 1987 (Exhibit 4, September 30, 1987 Form 10-Q, File No. 1-2323).
4b(54)	February 24, 1988 (Exhibit 4b(54), 1987 Form 10-K, File No. 1-2323).
4b(55)	September 15, 1988 (Exhibit 4b(55), 1988 Form 10-K, File No. 1-2323).
4b(56)	May 15, 1989 (Exhibit 4(a)(2)(i), File No. 33-32724).
4b(57)	June 13, 1989 (Exhibit 4(a)(2)(ii), File No. 33-32724).
4b(58)	October 15, 1989 (Exhibit 4(a)(2)(iii), File No. 33-32724).
4b(59)	January 1, 1990 (Exhibit 4b(59), 1989 Form 10-K, File No. 1-2323).
4b(60)	June 1, 1990 (Exhibit 4(a). September 30, 1990 Form 10-Q, File No. 1-2323).
4b(61)	August 1, 1990 (Exhibit 4(b), September 30, 1990 Form 10-Q, File No. 1-2323).
4b(62)	May 1, 1991 (Exhibit 4(a), June 30, 1991 Form 10-Q, File No. 1-2323).
4b(63)	May 1, 1992 (Exhibit 4(a)(3), File No. 33-48845).
4b(64)	July 31, 1992 (Exhibit 4(a)(3), File No. 33-57292).
4b(65)	January 1, 1993 (Exhibit 4b(65), 1992 Form 10-K, File No. 1-2323).
4b(66)	February 1, 1993 (Exhibit 4b(66), 1992 Form 10-K, File No. 1-2323).
4b(67)	May 20, 1993 (Exhibit 4(a), July 14, 1993 Form 8-K, File No. 1-2323).
4b(68)	June 1, 1993 (Exhibit 4(b), July 14, 1993 Form 8-K, File No. 1-2323).
4b(69)	September 15, 1994 (Exhibit 4(a), September 30, 1994 Form 10-Q, File No. 1-2323).
4b(70)	May 1, 1995 (Exhibit 4(a), September 30, 1995 Form 10-Q, File No. 1-2323).
4b(71)	May 2, 1995 (Exhibit 4(b), September 30, 1995 Form 10-Q, File No. 1-2323).
4b(72)	June 1, 1995 (Exhibit 4(c), September 30, 1995 Form 10-Q, File No. 1-2323).
4b(73)	July 15, 1995 (Exhibit 4b(73), 1995 Form 10-K, File No. 1-2323).
4b(74)	August 1, 1995 (Exhibit 4b(74), 1995 Form 10-K, File No. 1-2323).
4b(75)	June 15, 1997 (Exhibit 4(a), Form S-4 File No. 333-35931, filed by Cleveland Electric and Toledo Edison).
4b(76)	October 15, 1997 (Exhibit 4(a), Form S-4 File No. 333-47651, filed by Cleveland Electric).
4b(77)	June 1, 1998 (Exhibit 4b(77), Form S-4 File No. 333-72891).
4b(78)	October 1, 1998 (Exhibit 4b(78), Form S-4 File No. 333-72891).
4b(79)	October 1, 1998 (Exhibit 4b(79), Form S-4 File No. 333-72891).
4b(80)	February 24, 1999 (Exhibit 4b(80), Form S-4 File No. 333-72891).
4b(81)	September 29, 1999. (Exhibit 4b(81), 1999 Form 10-K, File No. 1-2323).
4b(82)	January 15, 2000. (Exhibit 4b(82), 1999 Form 10-K, File No. 1-2323).
4b(83)	May 15, 2002 (Exhibit 4b(83), 2002 Form 10-K, File No. 1-2323).
4b(84)	October 1, 2002 (Exhibit 4b(84), 2002 Form 10-K, File No. 1-2323).
4b(85)	Supplemental Indenture dated as of September 1, 2004 (Exhibit 4-1(85), September 2004 10-Q, File No. 1-2323).
4b(86)	Supplemental Indenture dated as of October 1, 2004 (Exhibit 4-1(86), September 2004 10-Q, File No. 1-2323).
4d	Form of Note Indenture between Cleveland Electric and The Chase Manhattan Bank, as Trustee dated as of October 24, 1997 (Exhibit 4(b), Form S-4 File No. 333-47651, filed by Cleveland Electric).
4d(1)	Form of Supplemental Note Indenture between Cleveland Electric and The Chase Manhattan Bank, as Trustee dated as of October 24, 1997 (Exhibit 4(c), Form S-4 File No. 333-47651; filed by Cleveland Electric).
4-1	Indenture dated as of December 1, 2003 between CEI and JPMorgan Chase Bank, as Trustee, Incorporated by reference to Exhibit 4-8, 2003 Annual Report on Form 10-K, SEC File No. 1-02323.
10-1	Administration Agreement between the CAPCO Group dated as of September 14, 1967. (Registration No. 2-43102, Exhibit 5(c)(2).)
10-2	Amendment No. 1 dated January 4, 1974 to Administration Agreement between the CAPCO Group dated as of September 14, 1967. (Registration No. 2-68906, Exhibit 5(c)(3).)

Exhibit Number	
10-3	Transmission Facilities Agreement between the CAPCO Group dated as of September 14, 1967. (Registration No. 2-43102, Exhibit 5(c)(3).)
10-4	Amendment No. 1 dated as of January 1, 1993 to Transmission Facilities Agreement between the CAPCO Group dated as of September 14, 1967. (1993 Form 10-K, Exhibit 10-4.)
10-5	Agreement for the Termination or Construction of Certain Agreements effective September 1, 1980, October 15, 1997 (Exhibit 4(a), Form S-4 File No. 333-47651, filed by Cleveland Electric).
10-6	Electric Power Supply Agreement, between the Cleveland Electric Illuminating Company, Ohio Edison Company, Pennsylvania Power Company, the Toledo Edison Company, and First Energy Solutions Corp. (f.k.a. FirstEnergy Services Corp.), dated January 1, 2001. (Filed as Ohio Edison Exhibit 10-145 in 2004 Form 10-K)
10-7	Revised Electric Power Supply Agreement, between FirstEnergy Solutions Corp., the Cleveland Electric Illuminating Company, Ohio Edison Company, Pennsylvania Power Company, and the Toledo Edison Company, dated October 1, 2003. (Filed as Ohio Edison Exhibit 10-146 in 2004 Form 10-K)
10-8	Master Facility Lease, between Ohio Edison Company, Pennsylvania Power Company, the Cleveland Electric Illuminating Company, the Toledo Edison Company, and FirstEnergy Generation Corp., dated January 1, 2001. (Filed as Ohio Edison Exhibit 10-147 in 2004 Form 10-K)
(A)12.3	Consolidated fixed charge ratios.
(A)13.2	CEI 2004 Annual Report to Stockholders. (Only those portions expressly incorporated by reference in this Form 10-K are to be deemed "filed" with the SEC.)
(A)21.2	List of Subsidiaries of the Registrant at December 31, 2004.
(A)	Provided herein in electronic format as an exhibit.
(B)	*Pursuant to paragraph (b)(4)(iii)(A) of Item 601 of Regulation S-K, CEI has not filed as an exhibit* to this Form 10-K any instrument with respect to long-term debt if the total amount of securities authorized thereunder does not exceed 10% of the total assets of CEI, but hereby agrees to furnish to the Commission on request any such instruments.

3. Exhibits – Toledo Edison (TE)

Exhibit Number	
3a	Amended Articles of Incorporation of TE, as amended effective October 2, 1992 (Exhibit 3a, 1992 Form 10-K, File No. 1-3583).
3b	Amended and Restated Code of Regulations, dated March 15, 2002. (2001 Form 10-K, Exhibit 3b)
(B)4b(1)	Indenture, dated as of April 1, 1947, between TE and The Chase National Bank of the City of New York (now The Chase Manhattan Bank (National Association)) (Exhibit 2(b), File No. 2-26908).
4b(2)	September 1, 1948 (Exhibit 2(d), File No. 2-26908).
4b(3)	April 1, 1949 (Exhibit 2(e), File No. 2-26908).
4b(4)	December 1, 1950 (Exhibit 2(f), File No. 2-26908).
4b(5)	March 1, 1954 (Exhibit 2(g), File No. 2-26908).
4b(6)	February 1, 1956 (Exhibit 2(h), File No. 2-26908).
4b(7)	May 1, 1958 (Exhibit 5(g), File No. 2-59794).
4b(8)	August 1, 1967 (Exhibit 2(c), File No. 2-26908).
4b(9)	November 1, 1970 (Exhibit 2(c), File No. 2-38569).
4b(10)	August 1, 1972 (Exhibit 2(c), File No. 2-44873).

Exhibit Number	
4b(11)	November 1, 1973 (Exhibit 2(c), File No. 2-49428).
4b(12)	July 1, 1974 (Exhibit 2(c), File No. 2-51429).
4b(13)	October 1, 1975 (Exhibit 2(c), File No. 2-54627).
4b(14)	June 1, 1976 (Exhibit 2(c), File No. 2-56396).
4b(15)	October 1, 1978 (Exhibit 2(c), File No. 2-62568).
4b(16)	September 1, 1979 (Exhibit 2(c), File No. 2-65350).
4b(17)	September 1, 1980 (Exhibit 4(s), File No. 2-69190).
4b(18)	October 1, 1980 (Exhibit 4(c), File No. 2-69190).
4b(19)	April 1, 1981 (Exhibit 4(c), File No. 2-71580).
4b(20)	November 1, 1981 (Exhibit 4(c), File No. 2-74485).
4b(21)	June 1, 1982 (Exhibit 4(c), File No. 2-77763).
4b(22)	September 1, 1982 (Exhibit 4(x), File No. 2-87323).
4b(23)	April 1, 1983 (Exhibit 4(c), March 31, 1983, Form 10-Q, File No. 1-3583).
4b(24)	December 1, 1983 (Exhibit 4(x), 1983 Form 10-K, File No. 1-3583).
4b(25)	April 1, 1984 (Exhibit 4(c), File No. 2-90059).
4b(26)	October 15, 1984 (Exhibit 4(z), 1984 Form 10-K, File No. 1-3583).
4b(27)	October 15, 1984 (Exhibit 4(aa), 1984 Form 10-K, File No. 1-3583).
4b(28)	August 1, 1985 (Exhibit 4(dd), File No. 33-1689).
4b(29)	August 1, 1985 (Exhibit 4(ee), File No. 33-1689).
4b(30)	December 1, 1985 (Exhibit 4(c), File No. 33-1689).
4b(31)	March 1, 1986 (Exhibit 4b(31), 1986 Form 10-K, File No. 1-3583).
4b(32)	October 15, 1987 (Exhibit 4, September 30, 1987 Form 10-Q, File No. 1-3583).
4b(33)	September 15, 1988 (Exhibit 4b(33), 1988 Form 10-K, File No. 1-3583).
4b(34)	June 15, 1989 (Exhibit 4b(34), 1989 Form 10-K, File No. 1-3583).
4b(35)	October 15, 1989 (Exhibit 4b(35), 1989 Form 10-K, File No. 1-3583).
4b(36)	May 15, 1990 (Exhibit 4, June 30, 1990 Form 10-Q, File No. 1-3583).
4b(37)	March 1, 1991 (Exhibit 4(b), June 30, 1991 Form 10-Q, File No. 1-3583).
4b(38)	May 1, 1992 (Exhibit 4(a)(3), File No. 33-48844).
4b(39)	August 1, 1992 (Exhibit 4b(39), 1992 Form 10-K, File No. 1-3583).
4b(40)	October 1, 1992 (Exhibit 4b(40), 1992 Form 10-K, File No. 1-3583).
4b(41)	January 1, 1993 (Exhibit 4b(41), 1992 Form 10-K, File No. 1-3583).
4b(42)	September 15, 1994 (Exhibit 4(b), September 30, 1994 Form 10-Q, File No. 1-3583).
4b(43)	May 1, 1995 (Exhibit 4(d), September 30, 1995 Form 10-Q, File No. 1-3583).
4b(44)	June 1, 1995 (Exhibit 4(e), September 30, 1995 Form 10-Q, File No. 1-3583).
4b(45)	July 14, 1995 (Exhibit 4(f), September 30, 1995 Form 10-Q, File No. 1-3583).
4b(46)	July 15, 1995 (Exhibit 4(g), September 30, 1995 Form 10-Q, File No. 1-3583).
4b(47)	August 1, 1997 (Exhibit 4b(47), 1998 Form 10-K, File No. 1-3583).
4b(48)	June 1, 1998 (Exhibit 4b (48), 1998 Form 10-K, File No. 1-3583).
4b(49)	January 15, 2000 (Exhibit 4b(49), 1999 Form 10-K, File No. 1-3583).
4b(50)	May 1, 2000 (Exhibit 4b(50), 2000 Form 10-K, File No. 1-3583).
4b(51)	September 1, 2000 (Exhibit 4b(51), 2002 Form 10-K, File No. 1-3583).
4b(52)	October 1, 2002 (Exhibit 4b(52), 2002 Form 10-K, File No. 1-3583).
4b(53)	April 1, 2003 (Exhibit 4b(53).
10-1	Electric Power Supply Agreement, between the Cleveland Electric Illuminating Company, Ohio Edison Company, Pennsylvania Power Company, the Toledo Edison Company, and First Energy Solutions Corp. (f.k.a. FirstEnergy Services Corp.), dated January 1, 2001.(Filed as Ohio Edison Exhibit 10-145 in 2004 Form 10-K)
10-2	Revised Electric Power Supply Agreement, between FirstEnergy Solutions Corp., the Cleveland Electric Illuminating Company, Ohio Edison Company, Pennsylvania Power Company, and the Toledo Edison Company, dated October 1, 2003. (Filed as Ohio Edison Exhibit 10-146 in 2004 Form 10-K)
10-3	Master Facility Lease, between Ohio Edison Company, Pennsylvania Power Company, the Cleveland Electric Illuminating Company, the Toledo Edison Company, and FirstEnergy Generation Corp., dated January 1, 2001. (Filed as Ohio Edison Exhibit 10-147 in 2004 Form 10-K)
(A)12.4	Consolidated fixed charge ratios.
(A)13.3	TE 2004 Annual Report to Stockholders. (Only those portions expressly incorporated by reference in this Form 10-K are to be deemed "filed" with the SEC.)

Exhibit
Number

(A)21.3	List of Subsidiaries of the Registrant at December 31, 2004.
(A)	Provided herein in electronic format as an exhibit.
(B)	Pursuant to paragraph (b)(4)(iii)(A) of Item 601 of Regulation S-K, TE has not filed as an exhibit to this Form 10-K any instrument with respect to long-term debt if the total amount of securities authorized thereunder does not exceed 10% of the total assets of TE, but hereby agrees to furnish to the Commission on request any such instruments.

3. ***Exhibits – Exhibits for Jersey Central Power & Light Company (JCP&L)***

3-A	Restated Certificate of Incorporation of JCP&L, as amended - Incorporated by reference to Exhibit 3-A, 1990 Annual Report on Form 10-K, SEC File No. 1-3141.
3-A-1	Certificate of Amendment to Restated Certificate of Incorporation of JCP&L, dated June 19, 1992 - Incorporated by reference to Exhibit A-2(a), Certificate Pursuant to Rule 24, SEC File No. 70-7949.
3-A-2	Certificate of Amendment to Restated Certificate of Incorporation of JCP&L, dated June 19, 1992 - Incorporated by reference to Exhibit A-2(a)(i), Certificate Pursuant to Rule 24, SEC File No. 70-7949.
3-B	By-Laws of JCP&L, as amended May 25, 1993 - Incorporated by reference to Exhibit 3-B, 1993 Annual Report on Form 10-K, SEC File No. 1-3141.
4-A	Indenture of JCP&L, dated March 1, 1946, between JCP&L and United States Trust Company of New York, Successor Trustee, as amended and supplemented by eight supplemental indentures dated December 1, 1948 through June 1, 1960 - Incorporated by reference to JCP&L's Instruments of Indebtedness Nos. 1 to 7, inclusive, and 9 and 10 filed as part of Amendment No. 1 to 1959 Annual Report of GPU on Form U5S, SEC File Nos. 30-126 and 1-3292.
4-A-1	Ninth Supplemental Indenture of JCP&L, dated November 1, 1962 - Incorporated by reference to Exhibit 2-C, Registration No. 2-20732.
4-A-2	Tenth Supplemental Indenture of JCP&L, dated October 1, 1963 - Incorporated by reference to Exhibit 2-C, Registration No. 2-21645.
4-A-3	Eleventh Supplemental Indenture of JCP&L, dated October 1, 1964 - Incorporated by reference to Exhibit 5-A-3, Registration No. 2-59785.
4-A-4	Twelfth Supplemental Indenture of JCP&L, dated November 1, 1965 - Incorporated by reference to Exhibit 5-A-4, Registration No. 2-59785.
4-A-5	Thirteenth Supplemental Indenture of JCP&L, dated August 1, 1966 - Incorporated by reference to Exhibit 4-C, Registration No. 2-25124.
4-A-6	Fourteenth Supplemental Indenture of JCP&L, dated September 1, 1967 - Incorporated by reference to Exhibit 5-A-6, Registration No. 2-59785.
4-A-7	Fifteenth Supplemental Indenture of JCP&L, dated October 1, 1968 - Incorporated by reference to Exhibit 5-A-7, Registration No. 2-59785.
4-A-8	Sixteenth Supplemental Indenture of JCP&L, dated October 1, 1969 - Incorporated by reference to Exhibit 5-A-8, Registration No. 2-59785.
4-A-9	Seventeenth Supplemental Indenture of JCP&L, dated June 1, 1970 - Incorporated by reference to Exhibit 5-A-9, Registration No. 2-59785.
4-A-10	Eighteenth Supplemental Indenture of JCP&L, dated December 1, 1970 - Incorporated by reference to Exhibit 5-A-10, Registration No. 2-59785.

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4-A-11	Nineteenth Supplemental Indenture of JCP&L, dated February 1, 1971 - Incorporated by reference to Exhibit 5-A-11, Registration No. 2-59785.
4-A-12	Twentieth Supplemental Indenture of JCP&L, dated November 1, 1971 - Incorporated by reference to Exhibit 5-A-12, Registration No. 2-59875.
4-A-13	Twenty-first Supplemental Indenture of JCP&L, dated August 1, 1972 - Incorporated by reference to Exhibit 5-A-13, Registration No. 2-59785.
4-A-14	Twenty-second Supplemental Indenture of JCP&L, dated August 1, 1973 - Incorporated by reference to Exhibit 5-A-14, Registration No. 2-59785.
4-A-15	Twenty-third Supplemental Indenture of JCP&L, dated October 1, 1973 - Incorporated by reference to Exhibit 5-A-15, Registration No. 2-59785.
4-A-16	Twenty-fourth Supplemental Indenture of JCP&L, dated December 1, 1973 - Incorporated by reference to Exhibit 5-A-16, Registration No. 2-59785.
4-A-17	Twenty-fifth Supplemental Indenture of JCP&L, dated November 1, 1974 - Incorporated by reference to Exhibit 5-A-17, Registration No. 2-59785.
4-A-18	Twenty-sixth Supplemental Indenture of JCP&L, dated March 1, 1975 - Incorporated by reference to Exhibit 5-A-18, Registration No. 2-59785.
4-A-19	Twenty-seventh Supplemental Indenture of JCP&L, dated July 1, 1975 - Incorporated by reference to Exhibit 5-A-19, Registration No. 2-59785.
4-A-20	Twenty-eighth Supplemental Indenture of JCP&L, dated October 1, 1975 - Incorporated by reference to Exhibit 5-A-20, Registration No. 2-59785.
4-A-21	Twenty-ninth Supplemental Indenture of JCP&L, dated February 1, 1976 - Incorporated by reference to Exhibit 5-A-21, Registration No. 2-59785.
4-A-22	Supplemental Indenture No. 29A of JCP&L, dated May 31, 1976 - Incorporated by reference to Exhibit 5-A-22, Registration No. 2-59785.
4-A-23	Thirtieth Supplemental Indenture of JCP&L, dated June 1, 1976 - Incorporated by reference to Exhibit 5-A-23, Registration No. 2-59785.
4-A-24	Thirty-first Supplemental Indenture of JCP&L, dated May 1, 1977 - Incorporated by reference to Exhibit 5-A-24, Registration No. 2-59785.
4-A-25	Thirty-second Supplemental Indenture of JCP&L, dated January 20, 1978 - Incorporated by reference to Exhibit 5-A-25, Registration No. 2-60438.
4-A-26	Thirty-third Supplemental Indenture of JCP&L, dated January 1, 1979 - Incorporated by reference to Exhibit A-20(b), Certificate Pursuant to Rule 24, SEC File No. 70-6242.
4-A-27	Thirty-fourth Supplemental Indenture of JCP&L, dated June 1, 1979 - Incorporated by reference to Exhibit A-28, Certificate Pursuant to Rule 24, SEC File No. 70-6290.
4-A-28	Thirty-sixth Supplemental Indenture of JCP&L, dated October 1, 1979 - Incorporated by reference to Exhibit A-30, Certificate Pursuant to Rule 24, SEC File No. 70-6354.
4-A-29	Thirty-seventh Supplemental Indenture of JCP&L, dated September 1, 1984 - Incorporated by reference to Exhibit A-1(cc), Certificate Pursuant to Rule 24, SEC File No. 70-7001.
4-A-30	Thirty-eighth Supplemental Indenture of JCP&L, dated July 1, 1985 - Incorporated by reference to Exhibit A-1(dd), Certificate Pursuant to Rule 24, SEC File No. 70-7109.
4-A-31	Thirty-ninth Supplemental Indenture of JCP&L, dated April 1, 1988 - Incorporated by reference to Exhibit A-1(a), Certificate Pursuant to Rule 24, SEC File No. 70-7263.

Exhibit Number	
4-A-32	Fortieth Supplemental Indenture of JCP&L, dated June 14, 1988 - Incorporated by reference to Exhibit A-1(ff), Certificate Pursuant to Rule 24, SEC File No. 70-7603.
4-A-33	Forty-first Supplemental Indenture of JCP&L, dated April 1, 1989 - Incorporated by reference to Exhibit A-1(gg), Certificate Pursuant to Rule 24, SEC File No. 70-7603.
4-A-34	Forty-second Supplemental Indenture of JCP&L, dated July 1, 1989 - Incorporated by reference to Exhibit A-1(hh), Certificate Pursuant to Rule 24, SEC File No. 70-7603.
4-A-35	Forty-third Supplemental Indenture of JCP&L, dated March 1, 1991 - Incorporated by reference to Exhibit 4-A-35, Registration No. 33-45314.
4-A-36	Forty-fourth Supplemental Indenture of JCP&L, dated March 1, 1992 - Incorporated by reference to Exhibit 4-A-36, Registration No. 33-49405.
4-A-37	Forty-fifth Supplemental Indenture of JCP&L, dated October 1, 1992 - Incorporated by reference to Exhibit 4-A-37, Registration No. 33-49405.
4-A-38	Forty-sixth Supplemental Indenture of JCP&L, dated April 1, 1993 - Incorporated by reference to Exhibit C-15, 1992 Annual Report of GPU on Form U5S, SEC File No. 30-126.
4-A-39	Forty-seventh Supplemental Indenture of JCP&L, dated April 10, 1993 - Incorporated by reference to Exhibit C-16, 1992 Annual Report of GPU on Form U5S, SEC File No. 30-126.
4-A-40	Forty-eighth Supplemental Indenture of JCP&L, dated April 15, 1993 - Incorporated by reference to Exhibit C-17, 1992 Annual Report of GPU on Form U5S, SEC File No. 30-126.
4-A-41	Forty-ninth Supplemental Indenture of JCP&L, dated October 1, 1993 - Incorporated by reference to Exhibit C-18, 1993 Annual Report of GPU on Form U5S, SEC File No. 30-126.
4-A-42	Fiftieth Supplemental Indenture of JCP&L, dated August 1, 1994 - Incorporated by reference to Exhibit C-19, 1994 Annual Report of GPU on Form U5S, SEC File No. 30-126.
4-A-43	Fifty-first Supplemental Indenture of JCP&L, dated August 15, 1996 – Incorporated by reference to Exhibit 4-A-43, 1996 Annual Report on Form 10-K, SEC File No. 1-6047.
4-A-44	Fifty-second Supplemental Indenture of JCP&L, dated July 1, 1999 - Incorporated by reference to Exhibit 4-B-44, Registration No. 333-88783.
4-A-45	Fifty-third Supplemental Indenture of JCP&L, dated November 1, 1999 - Incorporated by reference to Exhibit 4-A-45, 1999 Annual Report on Form 10-K, SEC File No. 1-3141.
4-A-46	Subordinated Debenture Indenture of JCP&L, dated May 1, 1995 - Incorporated by reference to Exhibit A-8(a), Certificate Pursuant to Rule 24, SEC File No. 70-8495.
4-A-47	Fifty-fourth Supplemental Indenture of JCP&L, dated May 1, 2001, Incorporated by reference to Exhibit 4-4, 2001 Annual Report on Form 10-K, SEC File No. 1-3141.
(A)4-A-48	Fifty-fifth Supplemental Indenture of JCP&L, dated April 23, 2004.
4-D	Amended and Restated Limited Partnership Agreement of JCP&L Capital, L.P., dated May 11, 1995 - Incorporated by reference to Exhibit A-5(a), Certificate Pursuant to Rule 24, SEC File No. 70-8495.
4-E	Action Creating Series A Preferred Securities of JCP&L Capital, L.P., dated May 11, 1995 - Incorporated by reference to Exhibit A-6(a), Certificate Pursuant to Rule 24, SEC File No. 70-8495.
4-F	Payment and Guarantee Agreement of JCP&L, dated May 18, 1995 - Incorporated by reference to Exhibit B-1(a), Certificate Pursuant to Rule 24, SEC File No. 70-8495.
(A) 12.6	Consolidated fixed charge ratios - JCP&L.

Exhibit
<u>Number</u>

(A) 13.5	JCP&L 2004 Annual Report to Stockholders (Only those portions expressly incorporated by reference in this Form 10-K are to be deemed "filed" with SEC.)
(A)21.5	List of Subsidiaries of JCP&L at December 31, 2004.
(A)31.3	Certification of chief executive officer, as adopted pursuant to Rule 13a-15(e)/15d-15(e).
(A)32.2	Certification of chief executive officer and chief financial officer, pursuant to 18 U.S.C. Section 1350.
(A)	Provided herein electronic format as an exhibit.

3. Exhibits - Exhibits for Metropolitan Edison Company (Met-Ed)

3-C	Restated Articles of Incorporation of Met-Ed, dated March 8, 1999 – Incorporated by reference to Exhibit 3-E, 1999 Annual Report on Form 10-K, SEC File No. 1-446.
3-D	By-Laws of Met-Ed as amended May 16, 2000, Incorporated by reference to Exhibit 3-F, 2000 Annual Report on Form 10-K, SEC File No. 1-06047.
4-B	Indenture of Met-Ed, dated November 1, 1944, between Met-Ed and United States Trust Company of New York, Successor Trustee, as amended and supplemented by fourteen supplemental indentures dated February 1, 1947 through May 1, 1960 - Incorporated by reference to Met-Ed's Instruments of Indebtedness Nos. 1 to 14 inclusive, and 16, filed as part of Amendment No. 1 to 1959 Annual Report of GPU on Form U5S, SEC File Nos. 30-126 and 1-3292.
4-B-1	Supplemental Indenture of Met-Ed, dated December 1, 1962 - Incorporated by reference to Exhibit 2-E(1), Registration No. 2-59678.
4-B-2	Supplemental Indenture of Met-Ed, dated March 20, 1964 - Incorporated by reference to Exhibit 2-E(2), Registration No. 2-59678.
4-B-3	Supplemental Indenture of Met-Ed, dated July 1, 1965 - Incorporated by reference to Exhibit 2-E(3), Registration No. 2-59678.
4-B-4	Supplemental Indenture of Met-Ed, dated June 1, 1966 - Incorporated by reference to Exhibit 2-B-4, Registration No. 2-24883.
4-B-5	Supplemental Indenture of Met-Ed, dated March 22, 1968 - Incorporated by reference to Exhibit 4-C-5, Registration No. 2-29644.
4-B-6	Supplemental Indenture of Met-Ed, dated September 1, 1968 - Incorporated by reference to Exhibit 2-E(6), Registration No. 2-59678.
4-B-7	Supplemental Indenture of Met-Ed, dated August 1, 1969 - Incorporated by reference to Exhibit 2-E(7), Registration No. 2-59678.
4-B-8	Supplemental Indenture of Met-Ed, dated November 1, 1971 - Incorporated by reference to Exhibit 2-E(8), Registration No. 2-59678.
4-B-9	Supplemental Indenture of Met-Ed, dated May 1, 1972 - Incorporated by reference to Exhibit 2-E(9), Registration No. 2-59678.
4-B-10	Supplemental Indenture of Met-Ed, dated December 1, 1973 - Incorporated by reference to Exhibit 2-E(10), Registration No. 2-59678.
4-B-11	Supplemental Indenture of Met-Ed, dated October 30, 1974 - Incorporated by reference to Exhibit 2-E(11), Registration No. 2-59678.
4-B-12	Supplemental Indenture of Met-Ed, dated October 31, 1974 - Incorporated by reference to Exhibit 2-E(12), Registration No. 2-59678.

Exhibit Number	
4-B-13	Supplemental Indenture of Met-Ed, dated March 20, 1975 - Incorporated by reference to Exhibit 2-E(13), Registration No. 2-59678.
4-B-14	Supplemental Indenture of Met-Ed, dated September 25, 1975 - Incorporated by reference to Exhibit 2-E(15), Registration No. 2-59678.
4-B-15	Supplemental Indenture of Met-Ed, dated January 12, 1976 - Incorporated by reference to Exhibit 2-E(16), Registration No. 2-59678.
4-B-16	Supplemental Indenture of Met-Ed, dated March 1, 1976 - Incorporated by reference to Exhibit 2-E(17), Registration No. 2-59678.
4-B-17	Supplemental Indenture of Met-Ed, dated September 28, 1977 - Incorporated by reference to Exhibit 2-E(18), Registration No. 2-62212.
4-B-18	Supplemental Indenture of Met-Ed, dated January 1, 1978 - Incorporated by reference to Exhibit 2-E(19), Registration No. 2-62212.
4-B-19	Supplemental Indenture of Met-Ed, dated September 1, 1978 - Incorporated by reference to Exhibit 4-A(19), Registration No. 33-48937.
4-B-20	Supplemental Indenture of Met-Ed, dated June 1, 1979 - Incorporated by reference to Exhibit 4-A(20), Registration No. 33-48937.
4-B-21	Supplemental Indenture of Met-Ed, dated January 1, 1980 - Incorporated by reference to Exhibit 4-A(21), Registration No. 33-48937.
4-B-22	Supplemental Indenture of Met-Ed, dated September 1, 1981 - Incorporated by reference to Exhibit 4-A(22), Registration No. 33-48937.
4-B-23	Supplemental Indenture of Met-Ed, dated September 10, 1981 - Incorporated by reference to Exhibit 4-A(23), Registration No. 33-48937.
4-B-24	Supplemental Indenture of Met-Ed, dated December 1, 1982 - Incorporated by reference to Exhibit 4-A(24), Registration No. 33-48937.
4-B-25	Supplemental Indenture of Met-Ed, dated September 1, 1983 - Incorporated by reference to Exhibit 4-A(25), Registration No. 33-48937.
4-B-26	Supplemental Indenture of Met-Ed, dated September 1, 1984 - Incorporated by reference to Exhibit 4-A(26), Registration No. 33-48937.
4-B-27	Supplemental Indenture of Met-Ed, dated March 1, 1985 - Incorporated by reference to Exhibit 4-A(27), Registration No. 33-48937.
4-B-28	Supplemental Indenture of Met-Ed, dated September 1, 1985 - Incorporated by reference to Exhibit 4-A(28), Registration No. 33-48937.
4-B-29	Supplemental Indenture of Met-Ed, dated June 1, 1988 - Incorporated by reference to Exhibit 4-A(29), Registration No. 33-48937.
4-B-30	Supplemental Indenture of Met-Ed, dated April 1, 1990 - Incorporated by reference to Exhibit 4-A(30), Registration No. 33-48937.
4-B-31	Amendment dated May 22, 1990 to Supplemental Indenture of Met-Ed, dated April 1, 1990 - Incorporated by reference to Exhibit 4-A(31), Registration No. 33-48937.
4-B-32	Supplemental Indenture of Met-Ed, dated September 1, 1992 - Incorporated by reference to Exhibit 4-A(32)(a), Registration No. 33-48937.
4-B-33	Supplemental Indenture of Met-Ed, dated December 1, 1993 - Incorporated by reference to Exhibit C-58, 1993 Annual Report of GPU on Form U5S, SEC File No. 30-126.

Exhibit Number	
4-B-34	Supplemental Indenture of Met-Ed, dated July 15, 1995 - Incorporated by reference to Exhibit 4-B-35, 1995 Annual Report on Form 10-K, SEC File No. 1-446.
4-B-35	Supplemental Indenture of Met-Ed, dated August 15, 1996 - Incorporated by reference to Exhibit 4-B-35, 1996 Annual Report on Form 10-K, SEC File No. 1-446.
4-B-36	Supplemental Indenture of Met-Ed, dated May 1, 1997 - Incorporated by reference to Exhibit 4-B-36, 1997 Annual Report on Form 10-K, SEC File No. 1-446.
4-B-37	Supplemental Indenture of Met-Ed, dated July 1, 1999 – Incorporated by reference to Exhibit 4-B-38, 1999 Annual Report on Form 10-K, SEC File No. 1-446.
4-B-38	Indenture between Met-Ed and United States Trust Company of New York, dated May 1, 1999 - Incorporated by reference to Exhibit A-11(a), Certificate Pursuant to Rule 24, SEC File No. 70-9329.
4-B-39	Senior Note Indenture between Met-Ed and United States Trust Company of New York, dated July 1, 1999 Incorporated by reference to Exhibit C-154 to GPU, Inc.'s Annual Report on Form U5S for the year 1999, SEC File No. 30-126.
4-B-40	First Supplemental Indenture between Met-Ed and United States Trust Company of New York, dated August 1, 2000 – Incorporated by reference to Exhibit 4-A, June 30, 2000 Quarterly Report on Form 10-Q, SEC File No. 1-446.
4-B-41	Supplemental Indenture of Met-Ed, dated May 1, 2001 – Incorporated by reference to Exhibit 4-5, 2001 Annual Report on Form 10-K, SEC File No. 1-446.
4-B-42	Supplemental Indenture of Met-Ed, dated March 1,2003 – Incorporated by reference to Exhibit 4-10, 2003 Annual Report on Form 10-K, SEC File No. 1-446.
4-G	Payment and Guarantee Agreement of Met-Ed, dated May 28, 1999 - Incorporated by reference to Exhibit B-1(a), Certificate Pursuant to Rule 24, SEC No. 70-9329.
4-H	Amendment No. 1 to Payment and Guarantee Agreement of Met-Ed, dated November 23, 1999 - Incorporated by reference to Exhibit 4-H, 1999 Annual Report on Form 10-K, SEC File No. 1-446.
(A) 12.7	Consolidated fixed charge ratios - Met-Ed.
(A) 13.6	Met-Ed 2004 Annual Report to Stockholders (Only those portions expressly incorporated by reference in this Form 10-K are to be deemed "filed" with SEC.)
(A) 21.6	List of Subsidiaries of Met-Ed at December 31, 2004.
(A)	Provided herein electronic format as an exhibit.

3. Exhibits - Exhibits for Pennsylvania Electric Company (Penelec)

3-E	Restated Articles of Incorporation of Penelec, dated March 8, 1999 – Incorporated by reference to Exhibit 3-G, 1999 Annual Report on Form 10-K, SEC File No. 1-3522.
3-F	By-Laws of Penelec as amended May 16, 2000, Incorporated by reference to Exhibit 3-F, 2000 Annual Report on Form 10-K, SEC File No. 1-03522.
4-C	Mortgage and Deed of Trust of Penelec, dated January 1, 1942, between Penelec and United States Trust Company of New York, Successor Trustee, and indentures supplemental thereto dated March 7, 1942 through May 1, 1960 - Incorporated by reference to Penelec's Instruments of Indebtedness Nos. 1-20, inclusive, filed as a part of Amendment No. 1 to 1959 Annual Report of GPU on Form U5S, SEC File Nos. 30-126 and 1-3292.
4-C-1	Supplemental Indentures to Mortgage and Deed of Trust of Penelec, dated May 1, 1961 through December 1, 1977 - Incorporated by reference to Exhibit 2-D(1) to 2-D(19), Registration No. 2-61502.

Exhibit Number	
4-C-2	Supplemental Indenture of Penelec, dated June 1, 1978 - Incorporated by reference to Exhibit 4-A(2), Registration No. 33-49669.
4-C-3	Supplemental Indenture of Penelec, dated June 1, 1979 - Incorporated by reference to Exhibit 4-A(3), Registration No. 33-49669.
4-C-4	Supplemental Indenture of Penelec, dated September 1, 1984 - Incorporated by reference to Exhibit 4-A(4), Registration No. 33-49669.
4-C-5	Supplemental Indenture of Penelec, dated December 1, 1985 - Incorporated by reference to Exhibit 4-A(5), Registration No. 33-49669.
4-C-6	Supplemental Indenture of Penelec, dated December 1, 1986 - Incorporated by reference to Exhibit 4-A(6), Registration No. 33-49669.
4-C-7	Supplemental Indenture of Penelec, dated May 1, 1989 - Incorporated by reference to Exhibit 4-A(7), Registration No. 33-49669.
4-C-8	Supplemental Indenture of Penelec, dated December 1, 1990-Incorporated by reference to Exhibit 4-A(8), Registration No. 33-45312.
4-C-9	Supplemental Indenture of Penelec, dated March 1, 1992 - Incorporated by reference to Exhibit 4-A(9), Registration No. 33-45312.
4-C-10	Supplemental Indenture of Penelec, dated June 1, 1993 - Incorporated by reference to Exhibit C-73, 1993 Annual Report of GPU on Form U5S, SEC File No. 30-126.
4-C-11	Supplemental Indenture of Penelec, dated November 1, 1995 - Incorporated by reference to Exhibit 4-C-11, 1995 Annual Report on Form 10-K, SEC File No. 1-3522.
4-C-12	Supplemental Indenture of Penelec, dated August 15, 1996 - Incorporated by reference to Exhibit 4-C-12, 1996 Annual Report on Form 10-K, SEC File No. 1-3522.
4-C-13	Senior Note Indenture between Penelec and United States Trust Company of New York, dated April 1, 1999 - Incorporated by reference to Exhibit 4-C-13, 1999 Annual Report on Form 10-K, SEC File No. 1-3522.
4-C-14	Indenture between Penelec and United States Trust Company of New York, dated June 1, 1999 - Incorporated by reference to Exhibit A-11(a), Certificate Pursuant to Rule 24, SEC File No. 70-9327.
4-C-15	First Supplemental Indenture between Penelec and United States Trust Company of New York, dated August 1, 2000 - Incorporated by reference to Exhibit 4-B, June 30, 2000 Quarterly Report on Form 10-Q, SEC File No. 1-3522.
4-C-16	Supplemental Indenture of Penelec, dated May 1, 2001.
4-C-17	Supplemental Indenture No. 1 of Penelec, dated May 1, 2001.
4-I	Payment and Guarantee Agreement of Penelec, dated June 16, 1999 - Incorporated by reference to Exhibit B-1(a), Certificate Pursuant to Rule 24, SEC File No. 70-9327.
4-J	Amendment No. 1 to Payment and Guarantee Agreement of Penelec, dated November 23, 1999 - Incorporated by reference to Exhibit 4-J, 1999 Annual Report on Form 10-K, SEC File No. 1-3522.
(A) 12.8	Consolidated fixed charge ratios - Penelec.
(A) 13.7	Penelec 2004 Annual Report to Stockholders (Only those portions expressly incorporated by reference in this Form 10-K are to be deemed "filed" with SEC.)
(A) 21.7	List of Subsidiaries of Penelec at December 31, 2004.

Exhibit
<u>Number</u>

(A) 23.3	Consent of Independent Registered Public Accounting Firm- Penelec.
(A)	Provided here in electronic format as an exhibit.

3. Exhibits - Combined Exhibit for Met-Ed and Penelec

(A)10-1	First Amendment to Restated Partial Requirements Agreement, between Met-Ed, Penelec, and FES, dated January 1, 2003.
(A)	Provided here in electronic format as an exhibit.

Report of Independent Registered Public Accounting Firm

on

Financial Statement Schedules

To the Board of Directors of
FirstEnergy Corp.:

Our audits of the consolidated financial statements, of management's assessment of the effectiveness of internal control over financial reporting and of the effectiveness of internal control over financial reporting referred to in our report dated March 7, 2005 appearing in the 2004 Annual Report to Stockholders of FirstEnergy Corp. (which report, consolidated financial statements and assessment are incorporated by reference in this Annual Report on Form 10-K) also included an audit of the financial statement schedules listed in Item 15(a)(2) of this Form 10-K. In our opinion, these financial statement schedules present fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements.

PricewaterhouseCoopers LLP

Cleveland, Ohio
March 7, 2005

Report of Independent Registered Public Accounting Firm

on

Financial Statement Schedules

To the Board of Directors of
Ohio Edison Company:

Our audits of the consolidated financial statements, of management's assessment of the effectiveness of internal control over financial reporting and of the effectiveness of internal control over financial reporting referred to in our report dated March 7, 2005 appearing in the 2004 Annual Report to Stockholders of Ohio Edison Company (which report, consolidated financial statements and assessment are incorporated by reference in this Annual Report on Form 10-K) also included an audit of the financial statement schedules listed in Item 15(a)(2) of this Form 10-K. In our opinion, these financial statement schedules present fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements.

PricewaterhouseCoopers LLP

Cleveland, Ohio
March 7, 2005

Report of Independent Registered Public Accounting Firm

on

Financial Statement Schedules

To the Board of Directors of
The Cleveland Electric Illuminating Company:

Our audits of the consolidated financial statements, of management's assessment of the effectiveness of internal control over financial reporting and of the effectiveness of internal control over financial reporting referred to in our report dated March 7, 2005 appearing in the 2004 Annual Report to Stockholders of The Cleveland Electric Illuminating Company (which report, consolidated financial statements and assessment are incorporated by reference in this Annual Report on Form 10-K) also included an audit of the financial statement schedules listed in Item 15(a)(2) of this Form 10-K. In our opinion, these financial statement schedules present fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements.

PricewaterhouseCoopers LLP

Cleveland, Ohio
March 7, 2005

Report of Independent Registered Public Accounting Firm

on

Financial Statement Schedules

To the Board of Directors of
The Toledo Edison Company:

Our audits of the consolidated financial statements, of management's assessment of the effectiveness of internal control over financial reporting and of the effectiveness of internal control over financial reporting referred to in our report dated March 7, 2005 appearing in the 2004 Annual Report to Stockholders of The Toledo Edison Company (which report, consolidated financial statements and assessment are incorporated by reference in this Annual Report on Form 10-K) also included an audit of the financial statement schedules listed in Item 15(a)(2) of this Form 10-K. In our opinion, these financial statement schedules present fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements.

PricewaterhouseCoopers LLP

Cleveland, Ohio
March 7, 2005

Report of Independent Registered Public Accounting Firm
on
Financial Statement Schedules

To the Board of Directors of
Pennsylvania Power Company:

Our audits of the consolidated financial statements, of management's assessment of the effectiveness of internal control over financial reporting and of the effectiveness of internal control over financial reporting referred to in our report dated March 7, 2005 appearing in the 2004 Annual Report to Stockholders of Pennsylvania Power Company (which report, consolidated financial statements and assessment are incorporated by reference in this Annual Report on Form 10-K) also included an audit of the financial statement schedules listed in Item 15(a)(2) of this Form 10-K. In our opinion, these financial statement schedules present fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements.

PricewaterhouseCoopers LLP

Cleveland, Ohio
March 7, 2005

Report of Independent Registered Public Accounting Firm

on

Financial Statement Schedules

To the Board of Directors of
Jersey Central Power
& Light Company:

Our audits of the consolidated financial statements, of management's assessment of the effectiveness of internal control over financial reporting and of the effectiveness of internal control over financial reporting referred to in our report dated March 7, 2005 appearing in the 2004 Annual Report to Stockholders of Jersey Central Power & Light Company (which report, consolidated financial statements and assessment are incorporated by reference in this Annual Report on Form 10-K) also included an audit of the financial statement schedules listed in Item 15(a)(2) of this Form 10-K. In our opinion, these financial statement schedules present fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements.

PricewaterhouseCoopers LLP

Cleveland, Ohio
March 7, 2005

Report of Independent Registered Public Accounting Firm

on

Financial Statement Schedules

To the Board of Directors of
Metropolitan Edison Company:

Our audits of the consolidated financial statements, of management's assessment of the effectiveness of internal control over financial reporting and of the effectiveness of internal control over financial reporting referred to in our report dated March 7, 2005 appearing in the 2004 Annual Report to Stockholders of Metropolitan Edison Company (which report, consolidated financial statements and assessment are incorporated by reference in this Annual Report on Form 10-K) also included an audit of the financial statement schedules listed in Item 15(a)(2) of this Form 10-K. In our opinion, these financial statement schedules present fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements.

PricewaterhouseCoopers LLP

Cleveland, Ohio
March 7, 2005

Report of Independent Registered Public Accounting Firm

on

Financial Statement Schedules

To the Board of Directors of
Pennsylvania Electric Company:

Our audits of the consolidated financial statements, of management's assessment of the effectiveness of internal control over financial reporting and of the effectiveness of internal control over financial reporting referred to in our report dated March 7, 2005 appearing in the 2004 Annual Report to Stockholders of Pennsylvania Electric Company (which report, consolidated financial statements and assessment are incorporated by reference in this Annual Report on Form 10-K) also included an audit of the financial statement schedules listed in Item 15(a)(2) of this Form 10-K. In our opinion, these financial statement schedules present fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements.

PricewaterhouseCoopers LLP

Cleveland, Ohio
March 7, 2005

SCHEDULE II

FIRSTENERGY CORP.

CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS FOR THE YEARS ENDED DECEMBER 31, 2004, 2003 AND 2002

Description		Beginning Balance	Additions: Charged to Income	Additions: Charged to Other Accounts	Deductions	Ending Balance
				(In thousands)		
Year Ended December 31, 2004:						
Accumulated provision for uncollectible accounts	- customers	$ 50,247	$ 38,492	$22,102(a)	$76,365(b)	$ 34,476
	- other	$ 18,283	$ 1,038	$15,836(a)	$ 9,087(b)	$ 26,070
Loss carryforward tax valuation reserve		$470,813	$(34,803)	$(16,032)	$ --	$ 419,978
Year Ended December 31, 2003:						
Accumulated provision for uncollectible accounts	- customers	$ 52,514	$ 63,535	$15,966(a)	$81,768(b)	$ 50,247
	- other	$ 12,851	$ 6,516	$10,002(a)	$11,086(b)	$ 18,283
Loss carryforward tax valuation reserve		$482,061	$ 29,575	$50,503	$91,326(c)	$470,813
Year Ended December 31, 2002:						
Accumulated provision for uncollectible accounts	- customers	$ 65,358	$ 43,601	$ 5,637(a)	$62,082(b)	$ 52,514
	- other	$ 7,947	$ 4,316	$ 4,089	$ 3,501	$ 12,851
Loss carryforward tax valuation reserve		$459,170	$17,500	$ 5,391	$ --	$482,061

(a) Represents recoveries and reinstatements of accounts previously written off.
(b) Represents the write-off of accounts considered to be uncollectible.
(c) Includes a reclassification of a valuation allowance to a contingent liability.

OHIO EDISON COMPANY

CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS
FOR THE YEARS ENDED DECEMBER 31, 2004, 2003 AND 2002

Description	Beginning Balance	Additions: Charged to Income	Additions: Charged to Other Accounts	Deductions	Ending Balance
			(In thousands)		
Year Ended December 31, 2004:					
Accumulated provision for uncollectible accounts - customers	$ 8,747	$17,477	$7,275(a)	$27,197(b)	$ 6,302
- other	$ 2,282	$ 376	$ 215(a)	$ 2,809(b)	$ 64
Year Ended December 31, 2003:					
Accumulated provision for uncollectible accounts - customers	$ 5,240	$18,157	$4,384(a)	$19,034(b)	$ 8,747
- other	$ 1,000	$ 1,282	$ --	$ --	$ 2,282
Year Ended December 31, 2002:					
Accumulated provision for uncollectible accounts - customers	$ 4,522	$12,792	$2,777(a)	$14,851(b)	$ 5,240
	$ 1,000	$ --	$ --	$ --	$ 1,000

(a) Represents recoveries and reinstatements of accounts previously written off.
(b) Represents the write-off of accounts considered to be uncollectible.

THE CLEVELAND ELECTRIC ILLUMINATING COMPANY

CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS
FOR THE YEARS ENDED DECEMBER 31, 2004, 2003 AND 2002

Description	Beginning Balance	Additions: Charged to Income	Additions: Charged to Other Accounts	Ending Deductions	Balance
			(In thousands)		
Year Ended December 31, 2004:					
Accumulated provision for uncollectible accounts	$ 1,765	$(1,181)	$ 12	$ 303	$ 293
Year Ended December 31, 2003:					
Accumulated provision for uncollectible accounts	$ 1,015	$ 765	$ --	$ 15	$1,765
Year Ended December 31, 2002:					
Accumulated provision for uncollectible accounts	$ 1,015	$ --	$ --	$ --	$1,015

SCHEDULE II

THE TOLEDO EDISON COMPANY

CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS
FOR THE YEARS ENDED DECEMBER 31, 2004, 2003 AND 2002

Description	Beginning Balance	Additions: Charged to Income	Additions: Charged to Other Accounts	Deductions	Ending Balance
			(In thousands)		
Year Ended December 31, 2004:					
Accumulated provision for uncollectible accounts	$ 34	$ (33)	$ 2(a)	$ 1(b)	$ 2
Year Ended December 31, 2003:					
Accumulated provision for uncollectible accounts	$ 2	$1,160	$ 712(a)	$1,840(b)	$ 34
Year Ended December 31, 2002:					
Accumulated provision for uncollectible accounts	$ 2	$ --	$ --	$ --	$ 2

(a) Represents recoveries and reinstatements of accounts previously written off.
(b) Represents the write-off of accounts considered to be uncollectible.

PENNSYLVANIA POWER COMPANY

VALUATION AND QUALIFYING ACCOUNTS
FOR THE YEARS ENDED DECEMBER 31, 2004, 2003 AND 2002

Description	Beginning Balance	Additions: Charged to Income	Additions: Charged to Other Accounts	Deductions	Ending Balance
			(In thousands)		
Year Ended December 31, 2004:					
Accumulated provision for uncollectible accounts - customers	$ 769	$2,467	$1,002(a)	$3,350(b)	$ 888
- other	$ 102	$ (93)	$ 13(a)	$ 16(b)	$ 6
Year Ended December 31, 2003:					
Accumulated provision for uncollectible accounts - customers	$ 702	$1,931	$ 644(a)	$2,528(b)	$ 769
- other	$ --	$ 102	$ --	$ --	$ 102
Year Ended December 31, 2002:					
Accumulated provision for uncollectible accounts - customers	$ 619	$1,808	$ 333(a)	$2,058(b)	$ 702

(a) Represents recoveries and reinstatements of accounts previously written off.
(b) Represents the write-off of accounts considered to be uncollectible.

JERSEY CENTRAL POWER & LIGHT COMPANY

CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS
FOR THE YEARS ENDED DECEMBER 31, 2004, 2003 AND 2002

Description	Beginning Balance	Additions: Charged to Income	Additions: Charged to Other Accounts	Deductions	Ending Balance
			(In thousands)		
Year Ended December 31, 2004:					
Accumulated provision for uncollectible accounts - customers	$ 4,296	$6,515	$3,664(a)	$10,594(b)	$3,881
- other	$ 1,183	$ (111)	$ (354)	$ 556	$ 162
Year Ended December 31, 2003:					
Accumulated provision for uncollectible accounts - customers	$ 4,509	$7,867	$2,991(a)	$11,071(b)	$4,296
- other	$ --	$1,183	$ --	$ --	$1,183
Year Ended December 31, 2002:					
Accumulated provision for uncollectible accounts - customers	$12,923	$9,057	$1,305(a)	$18,776(b)	$4,509

(a) Represents recoveries and reinstatements of accounts previously written off.
(b) Represents the write-off of accounts considered to be uncollectible.

METROPOLITAN EDISON COMPANY

CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS
FOR THE YEARS ENDED DECEMBER 31, 2004, 2003 AND 2002

		Additions			
Description	Beginning Balance	Charged to Income	Charged to Other Accounts	Deductions	Ending Balance
			(In thousands)		
Year Ended December 31, 2004:					
Accumulated provision for uncollectible accounts – customers	$4,943	$ 7,841	$5,128(a)	$13,334(b)	$4,578
- other	$ 68	$ (68)	$ --	$ --	$ --
Year Ended December 31, 2003:					
Accumulated provision for uncollectible accounts – customers	$ 4,810	$ 8,617	$4,595(a)	$13,079(b)	$4,943
- other	$ --	$ 68	$ --	$ --	$ 68
Year Ended December 31, 2002:					
Accumulated provision for uncollectible accounts - customers	$12,271	$ 3,332	$ 851(a)	$11,644(b)	$4,810

(a) Represents recoveries and reinstatements of accounts previously written off.
(b) Represents the write-off of accounts considered to be uncollectible.

PENNSYLVANIA ELECTRIC COMPANY

CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS
FOR THE YEARS ENDED DECEMBER 31, 2004, 2003 AND 2002

Description	Beginning Balance	Additions: Charged to Income	Additions: Charged to Other Accounts	Ending Deductions	Balance
			(In thousands)		
Year Ended December 31, 2004:					
Accumulated provision for uncollectible accounts – customers	$ 5,833	$ 5,977	$5,351(a)	$12,449(b)	$ 4,712
- other	$ 399	$ (324)	$ 24	$ 95	$ 4
Year Ended December 31, 2003:					
Accumulated provision for uncollectible accounts – customers	$ 6,216	$ 9,287	$3,995(a)	$13,665(b)	$ 5,833
- other	$ --	$ 399	$ --	$ --	$ 399
Year Ended December 31, 2002:					
Accumulated provision for uncollectible accounts - customers	$14,719	$ 2,991	$ 704(a)	$12,198(b)	$ 6,216

(a) Represents recoveries and reinstatements of accounts previously written off.
(b) Represents the write-off of accounts considered to be uncollectible.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

FIRSTENERGY CORP.

BY: /s/Anthony J. Alexander
Anthony J. Alexander
President and Chief Executive Officer

Date: March 9, 2005

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the date indicated:

/s/ George M. Smart
George M. Smart
Chairman of the Board

/s/ Anthony J. Alexander
Anthony J. Alexander
President and Chief Executive Officer
and Director (Principal Executive Officer)

/s/ Richard H. Marsh
Richard H. Marsh
Senior Vice President and Chief Financial Officer (Principal Financial Officer)

/s/ Harvey L. Wagner
Harvey L. Wagner
Vice President, Controller and Chief Accounting Officer (Principal Accounting Officer)

/s/ Paul T. Addison
Paul T. Addison
Director

/s/ Paul J. Powers
Paul J. Powers
Director

/s/ Carol A. Cartwright
Carol A. Cartwright
Director

/s/ Catherine A. Rein
Catherine A. Rein
Director

/s/ William T. Cottle
William T. Cottle
Director

/s/ Robert C. Savage
Robert C. Savage
Director

/s/ Russell W. Maier
Russell W. Maier
Director

/s/ Wes M. Taylor
Wes M. Taylor
Director

/s/ Ernest J. Novak, Jr.
Ernest J. Novak, Jr.
Director

/s/ Jesse T. Williams, Sr.
Jesse T. Williams, Sr.
Director

/s/ Robert N. Pokewaldt
Robert N. Pokewaldt
Director

/s/ Patricia K. Woolf
Patricia K. Woolf
Director

Date: March 9, 2005

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

OHIO EDISON COMPANY

BY: /s/ Anthony J. Alexander
Anthony J. Alexander
President

Date: March 9, 2005

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the date indicated:

/s/ Anthony J. Alexander
Anthony J. Alexander
President and Director
(Principal Executive Officer)

/s/ Richard R. Grigg
Richard R. Grigg
Executive Vice President and Chief Operating Officer and Director

/s/ Richard H. Marsh
Richard H. Marsh
Senior Vice President and Chief Financial Officer and Director
(Principal Financial Officer)

/s/ Harvey L. Wagner
Harvey L. Wagner
Vice President and Controller
(Principal Accounting Officer)

Date: March 9, 2005

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

THE CLEVELAND ELECTRIC ILLUMINATING COMPANY

BY: /s/ Anthony J. Alexander
Anthony J. Alexander
President

Date: March 9, 2005

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the date indicated:

/s/ Anthony J. Alexander
Anthony J. Alexander
President and Director
(Principal Executive Officer)

/s/ Richard R. Grigg
Richard R. Grigg
Executive Vice President and Chief
Operating Officer and Director

/s/ Richard H. Marsh
Richard H. Marsh
Senior Vice President and Chief
Financial Officer and Director
(Principal Financial Officer)

/s/ Harvey L. Wagner
Harvey L. Wagner
Vice President and Controller
(Principal Accounting Officer)

Date: March 9, 2005

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

THE TOLEDO EDISON COMPANY

BY: /s/ Anthony J. Alexander
Anthony J. Alexander
President

Date: March 9, 2005

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the date indicated:

/s/ Anthony J. Alexander
Anthony J. Alexander
President and Director
(Principal Executive Officer)

/s/ Richard R. Grigg
Richard R. Grigg
Executive Vice President and Chief Operating Officer and Director

/s/ Richard H. Marsh
Richard H. Marsh
Senior Vice President and Chief Financial Officer and Director
(Principal Financial Officer)

/s/ Harvey L. Wagner
Harvey L. Wagner
Vice President and Controller
(Principal Accounting Officer)

Date: March 9, 2005

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

JERSEY CENTRAL POWER & LIGHT COMPANY

BY: /s/ Stephen E. Morgan
Stephen E. Morgan
President

Date: March 9, 2005

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the date indicated:

/s/ Stephen E. Morgan
Stephen E. Morgan
President and Director
(Principal Executive Officer)

/s/ Richard H. Marsh
Richard H. Marsh
Senior Vice President and
Chief Financial Officer
(Principal Financial Officer)

/s/ Harvey L. Wagner
Harvey L. Wagner
Vice President and Controller
(Principal Accounting Officer)

/s/ Leila L. Vespoli
Leila L. Vespoli
Senior Vice President and
General Counsel and Director

/s/ Charles E. Jones
Charles E. Jones
Director

/s/ Stanley C. Van Ness
Stanley C. Van Ness
Director

/s/ Gelorma E. Persson
Gelorma E. Persson
Director

/s/ Mark A. Julian
Mark A. Julian
Director

/s/ Bradley S. Ewing
Bradley S. Ewing
Director

Date: March 9, 2005

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

METROPOLITAN EDISON COMPANY

BY: /s/ Anthony J. Alexander
Anthony J. Alexander
President

Date: March 9, 2005

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the date indicated:

/s/ Anthony J. Alexander
Anthony J. Alexander
President and Director
(Principal Executive Officer)

/s/ Richard R. Grigg
Richard R. Grigg
Executive Vice President and Chief Operating Officer and Director

/s/ Richard H. Marsh
Richard H. Marsh
Senior Vice President and Chief Financial Officer and Director
(Principal Financial Officer)

/s/ Harvey L. Wagner
Harvey L. Wagner
Vice President and Controller
(Principal Accounting Officer)

Date: March 9, 2005

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

PENNSYLVANIA ELECTRIC COMPANY

BY: /s/ Anthony J. Alexander
Anthony J. Alexander
President

Date: March 9, 2005

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the date indicated:

/s/ Anthony J. Alexander
Anthony J. Alexander
President and Director
(Principal Executive Officer)

/s/ Richard R. Grigg
Richard R. Grigg
Executive Vice President and Chief Operating Officer and Director

/s/ Richard H. Marsh
Richard H. Marsh
Senior Vice President and Chief Financial Officer and Director
(Principal Financial Officer)

/s/ Harvey L. Wagner
Harvey L. Wagner
Vice President and Controller
(Principal Accounting Officer)

Date: March 9, 2005

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

PENNSYLVANIA POWER COMPANY

BY: /s/ Anthony J. Alexander
Anthony J. Alexander
President

Date: March 9, 2005

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the date indicated:

/s/ Anthony J. Alexander
Anthony J. Alexander
President and Director
(Principal Executive Officer)

/s/ Richard R. Grigg
Richard R. Grigg
Executive Vice President and Chief
Operating Officer and Director

/s/ Richard H. Marsh
Richard H. Marsh
Senior Vice President and Chief
Financial Officer and Director
(Principal Financial Officer)

/s/ Harvey L. Wagner
Harvey L. Wagner
Vice President and Controller
(Principal Accounting Officer)

Date: March 9, 2005

EXHIBIT 12.1

FIRSTENERGY CORP.

CONSOLIDATED RATIO OF EARNINGS TO FIXED CHARGES

	Year Ended December 31,				
	2000	2001	2002	2003	2004
	(Dollars in thousands)				
EARNINGS AS DEFINED IN REGULATION S-K:					
Income before extraordinary items	$ 598,970	$ 654,946	$ 618,385	$ 424,249	$ 873,779
Interest and other charges, before reduction for amounts capitalized	556,194	591,192	980,344	841,280	692,358
Provision for income taxes	376,802	474,457	514,134	407,524	670,922
Interest element of rentals charged to income (a)	271,471	258,561	246,416	247,222	248,499
Earnings as defined	$1,803,437	$1,979,156	$2,359,279	$1,920,275	$2,485,558
FIXED CHARGES AS DEFINED IN REGULATION S-K:					
Interest expense	$ 493,473	$ 519,131	$ 904,697	$ 798,911	$ 670,945
Subsidiaries' preferred stock dividend requirements	62,721	72,061	75,647	42,369	21,413
Adjustments to subsidiaries' preferred stock dividends to state on a pre-income tax basis	32,098	41,349	28,426	22,519	16,442
Interest element of rentals charged to income (a)	271,471	258,561	246,416	247,222	248,499
Fixed charges as defined	$ 859,763	$ 891,102	$1,255,186	$1,111,021	$ 957,299
CONSOLIDATED RATIO OF EARNINGS TO FIXED CHARGES	2.10	2.22	1.88	1.73	2.60

(a) Includes the interest element of rentals where determinable plus 1/3 of rental expense where no readily defined interest element can be determined.

OHIO EDISON COMPANY

CONSOLIDATED RATIO OF EARNINGS TO FIXED CHARGES

	Year Ended December 31,				
	2000	2001	2002	2003	2004
	(Dollars in thousands)				
EARNINGS AS DEFINED IN REGULATION S-K:					
Income before extraordinary items	$336,456	$350,212	$356,159	$292,925	$342,766
Interest and other charges, before reduction for amounts capitalized	211,364	187,890	144,170	116,868	74,051
Provision for income taxes	212,580	239,135	255,915	241,173	278,303
Interest element of rentals charged to income (a)	109,497	104,507	102,469	107,611	104,239
Earnings as defined	$869,897	$881,744	$858,713	$758,577	$799,359
FIXED CHARGES AS DEFINED IN REGULATION S-K:					
Interest on long-term debt	$165,409	$150,632	$119,123	$ 91,068	$ 59,465
Other interest expense	31,451	22,754	14,598	22,069	12,026
Subsidiaries' preferred stock dividend requirements	14,504	14,504	10,449	3,731	2,560
Adjustments to subsidiaries' preferred stock dividends to state on a pre-income tax basis	2,296	2,481	2,661	3,014	1,975
Interest element of rentals charged to income (a)	109,497	104,507	102,469	107,611	104,239
Fixed charges as defined	$323,157	$294,878	$249,300	$227,493	$180,265
CONSOLIDATED RATIO OF EARNINGS TO FIXED CHARGES	2.69	2.99	3.44	3.33	4.43

(a) Includes the interest element of rentals where determinable plus 1/3 of rental expense where no readily defined interest element can be determined.

OHIO EDISON COMPANY

CONSOLIDATED RATIO OF EARNINGS TO FIXED CHARGES PLUS PREFERRED STOCK DIVIDEND REQUIREMENTS (PRE-INCOME TAX BASIS)

	Year Ended December 31,				
	2000	2001	2002	2003	2004
	(Dollars in thousands)				
EARNINGS AS DEFINED IN REGULATION S-K:					
Income before extraordinary items	$336,456	$350,212	$356,159	$292,925	$342,766
Interest and other charges, before reduction for amounts capitalized	211,364	187,890	144,170	116,868	74,051
Provision for income taxes	212,580	239,135	255,915	241,173	278,303
Interest element of rentals charged to income (a)	109,497	104,507	102,469	107,611	104,239
Earnings as defined	$869,897	$881,744	$858,713	$758,577	$799,359
FIXED CHARGES AS DEFINED IN REGULATION S-K PLUS PREFERRED STOCK DIVIDEND REQUIREMENTS (PRE-INCOME TAX BASIS):					
Interest on long-term debt	$165,409	$150,632	$119,123	$ 91,068	$59,465
Other interest expense	31,451	22,754	14,598	22,069	12,026
Preferred stock dividend requirements	25,628	25,206	16,959	6,463	5,062
Adjustments to preferred stock dividends to state on a pre-income tax basis	8,976	9,412	7,034	5,264	4,072
Interest element of rentals charged to income (a)	109,497	104,507	102,469	107,611	104,239
Fixed charges as defined plus preferred stock dividend requirements (pre-income tax basis)	$340,961	$312,511	$260,183	$232,475	$184,864
CONSOLIDATED RATIO OF EARNINGS TO FIXED CHARGES PLUS PREFERRED STOCK DIVIDEND REQUIREMENTS (PRE-INCOME TAX BASIS)	2.55	2.82	3.30	3.26	4.32

(a) Includes the interest element of rentals where determinable plus 1/3 of rental expense where no readily defined interest element can be determined.

THE CLEVELAND ELECTRIC ILLUMINATING COMPANY

CONSOLIDATED RATIO OF EARNINGS TO FIXED CHARGES

	Year Ended December 31,				
	2000	2001	2002	2003	2004
	(Dollars in thousands)				
EARNINGS AS DEFINED IN REGULATION S-K:					
Income before extraordinary items	$210,424	$177,905	$136,952	$197,033	$236,531
Interest and other charges, before reduction for amounts capitalized	201,739	192,102	189,502	164,132	138,678
Provision for income taxes	138,426	137,887	84,938	131,285	138,856
Interest element of rentals charged to income (a)	65,616	59,497	51,170	49,761	49,375
Earnings as defined	$616,205	$567,391	$462,562	$542,211	$563,440
FIXED CHARGES AS DEFINED IN REGULATION S-K:					
Interest expense	$201,739	$191,727	$180,602	$159,632	$138,678
Subsidiary's preferred stock dividend requirements	--	375	8,900	4,500	--
Interest element of rentals charged to income (a)	65,616	59,497	51,170	49,761	49,375
Fixed charges as defined	$267,355	$251,599	$240,672	$213,893	$188,053
CONSOLIDATED RATIO OF EARNINGS TO FIXED CHARGES	2.30	2.26	1.92	2.53	3.00

(a) Includes the interest element of rentals where determinable plus 1/3 of rental expense where no readily defined interest element can be determined.

THE CLEVELAND ELECTRIC ILLUMINATING COMPANY

CONSOLIDATED RATIO OF EARNINGS TO FIXED CHARGES PLUS PREFERRED STOCK DIVIDEND REQUIREMENTS (PRE-INCOME TAX BASIS)

	Year Ended December 31,				
	2000	2001	2002	2003	2004
	(Dollars in thousands)				
EARNINGS AS DEFINED IN REGULATION S-K:					
Income before extraordinary items	$210,424	$177,905	$136,952	$197,033	$236,531
Interest and other charges, before reduction for amounts capitalized	201,739	192,102	189,502	164,132	138,678
Provision for income taxes	138,426	137,887	84,938	131,285	138,856
Interest element of rentals charged to income (a)	65,616	59,497	51,170	49,761	49,375
Earnings as defined	$616,205	$567,391	$462,562	$542,211	$563,440
FIXED CHARGES AS DEFINED IN REGULATION S-K PLUS PREFERRED STOCK DIVIDEND REQUIREMENTS (PRE-INCOME TAX BASIS):					
Interest expense	$201,739	$191,727	$180,602	$159,632	$138,678
Preferred stock dividend requirements	20,843	25,213	24,590	12,026	7,008
Adjustments to preferred stock dividends to state on a pre-income tax basis	13,012	20,178	8,204	5,137	4,113
Interest element of rentals charged to income (a)	65,616	59,497	51,170	49,761	49,375
Fixed charges as defined plus preferred stock dividend requirements (pre-income tax basis)	$301,210	$296,615	$264,566	$226,556	$199,174
CONSOLIDATED RATIO OF EARNINGS TO FIXED CHARGES PLUS PREFERRED STOCK DIVIDEND REQUIREMENTS (PRE-INCOME TAX BASIS)	2.05	1.91	1.75	2.39	2.83

(a) Includes the interest element of rentals where determinable plus 1/3 of rental expense where no readily defined interest element can be determined.

THE TOLEDO EDISON COMPANY

CONSOLIDATED RATIO OF EARNINGS TO FIXED CHARGES

	Year Ended December 31,				
	2000	2001	2002	2002	2004
	(Dollars in thousands)				
EARNINGS AS DEFINED IN REGULATION S-K:					
Income before extraordinary items	$138,144	$ 42,691	$ (5,142)	$ 19,930	$ 86,283
Interest and other charges, before reduction for amounts capitalized	71,373	62,773	57,672	42,126	33,439
Provision for income taxes	78,780	26,362	(9,844)	5,394	52,350
Interest element of rentals charged to income (a)	96,358	92,108	87,174	84,894	82,879
Earnings as defined	$384,655	$223,934	$129,860	$152,344	$254,951
FIXED CHARGES AS DEFINED IN REGULATION S-K:					
Interest expense	$ 71,373	$ 62,773	$ 57,672	$ 42,126	$ 33,439
Interest element of rentals charged to income (a)	96,358	92,108	87,174	84,894	82,879
Fixed charges as defined	$167,731	$154,881	$144,846	$127,020	$116,318
CONSOLIDATED RATIO OF EARNINGS TO FIXED CHARGES	2.29	1.45	0.90	1.20	2.19

(a) Includes the interest element of rentals where determinable plus 1/3 of rental expense where no readily defined interest element can be determined.

THE TOLEDO EDISON COMPANY

CONSOLIDATED RATIO OF EARNINGS TO FIXED CHARGES PLUS PREFERRED STOCK DIVIDEND REQUIREMENTS (PRE-INCOME TAX BASIS)

	Year Ended December 31,				
	2000	2001	2002	2003	2004
	(Dollars in thousands)				
EARNINGS AS DEFINED IN REGULATION S-K:					
Income before extraordinary items	$138,144	$ 42,691	$ (5,142)	$ 19,930	$ 86,283
Interest and other charges, before reduction for amounts capitalized	71,373	62,773	57,672	42,126	33,439
Provision for income taxes	78,780	26,362	(9,844)	5,394	52,350
Interest element of rentals charged to income (a)	96,358	92,108	87,174	84,894	82,879
Earnings as defined	$384,655	$223,934	$129,860	$152,344	$254,951
FIXED CHARGES AS DEFINED IN REGULATION S-K PLUS PREFERRED STOCK DIVIDEND REQUIREMENTS (PRE-INCOME TAX BASIS):					
Interest expense	$ 71,373	$ 62,773	$ 57,672	$ 42,126	$ 33,439
Preferred stock dividend requirements	16,247	16,135	10,756	8,838	8,844
Adjustments to preferred stock dividends to state on a pre-income tax basis	10,143	10,167	4,146	2,158	5,366
Interest element of rentals charged to income (a)	96,358	92,108	87,174	84,894	82,879
Fixed charges as defined plus preferred stock dividend requirements (pre-income tax basis)	$194,121	$181,183	$159,748	$138,016	$130,528
CONSOLIDATED RATIO OF EARNINGS TO FIXED CHARGES PLUS PREFERRED STOCK DIVIDEND REQUIREMENTS (PRE-INCOME TAX BASIS)	1.98	1.24	0.81	1.10	1.95

(a) _ Includes the interest element of rentals where determinable plus 1/3 of rental expense where no readily defined interest element can be determined.

PENNSYLVANIA POWER COMPANY

RATIO OF EARNINGS TO FIXED CHARGES

	Year Ended December 31,				
	2000	2001	2002	2003	2004
	(Dollars in thousands)				
EARNINGS AS DEFINED IN REGULATION S-K:					
Income before extraordinary items	$22,847	$ 41,041	$ 47,717	$ 37,833	$59,076
Interest before reduction for amounts capitalized	20,437	18,172	16,674	15,526	9,731
Provision for income taxes	26,121	39,921	43,044	35,959	49,752
Interest element of rentals charged to income (a)	2,791	1,316	326	167	285
Earnings as defined	$72,196	$100,450	$107,761	$ 89,485	$118,844
FIXED CHARGES AS DEFINED IN REGULATION S-K:					
Interest on long-term debt	$18,651	$ 16,971	$ 15,521	$ 14,228	$8,250
Interest on nuclear fuel obligations	364	141	8	--	--
Other interest expense	1,422	1,060	1,145	1,298	1,481
Interest element of rentals charged to income (a)	2,791	1,316	326	167	285
Fixed charges as defined	$23,228	$ 19,488	$ 17,000	$ 15,693	$10,016
RATIO OF EARNINGS TO FIXED CHARGES	3.11	5.15	6.34	5.70	11.87

(a) Includes the interest element of rentals where determinable plus 1/3 of rental expense where no readily defined interest element can be determined.

PENNSYLVANIA POWER COMPANY

RATIO OF EARNINGS TO FIXED CHARGES PLUS PREFERRED STOCK DIVIDEND REQUIREMENTS (PRE-INCOME TAX BASIS)

	2000	2001	2002	2003	2004
	Year Ended December 31, (Dollars in thousands)				
EARNINGS AS DEFINED IN REGULATION S-K:					
Income before extraordinary items	$22,847	$ 41,041	$ 47,717	$37,833	$ 59,076
Interest before reduction for amounts capitalized	20,437	18,172	16,674	15,526	9,731
Provision for income taxes	26,121	39,921	43,044	35,959	49,752
Interest element of rentals charged to income (a)	2,791	1,316	326	167	285
Earnings as defined	$72,196	$100,450	$107,761	$89,485	$118,844
FIXED CHARGES AS DEFINED IN REGULATION S-K PLUS PREFERRED STOCK DIVIDEND REQUIREMENTS (PRE-INCOME TAX BASIS):					
Interest on long-term debt	$18,651	$ 16,971	$ 15,521	$14,228	$ 8,250
Interest on nuclear fuel obligations	364	141	8	--	--
Other interest expense	1,422	1,060	1,145	1,298	1,481
Preferred stock dividend requirements	3,704	3,703	3,699	3,731	2,560
Adjustment to preferred stock dividends to state on a pre-income tax basis	4,018	3,534	3,274	3,469	2,097
Interest element of rentals charged to income (a)	2,791	1,316	326	167	285
Fixed charges as defined plus preferred stock dividend requirements (pre-income tax basis)	$30,950	$ 26,725	$ 23,973	$22,893	$14,673
RATIO OF EARNINGS TO FIXED CHARGES PLUS PREFERRED STOCK DIVIDEND REQUIREMENTS (PRE-INCOME TAX BASIS)	2.33	3.76	4.50	3.91	8.10

(a) Includes the interest element of rentals where determinable plus 1/3 of rental expense where no readily defined interest element can be determined.

JERSEY CENTRAL POWER & LIGHT COMPANY

CONSOLIDATED RATIO OF EARNINGS TO FIXED CHARGES

	Year Ended December 31, 2000	Jan. 1- Nov. 6, 2001	Nov. 7- Dec. 31, 2001	Year Ended December 31, 2002	2003	2004
			(Dollars in thousands)			
EARNINGS AS DEFINED IN REGULATION S-K:						
Income before extraordinary items	$210,812	$ 34,467	$30,041	$251,895	$ 68,017	$111,639
Interest and other charges, before reduction for amounts capitalized	105,799	95,727	16,919	100,365	94,719	84,191
Provision for income taxes	119,875	52	20,101	181,855	46,440	95,112
Interest element of rentals charged to income (a)	6,229	3,913	124	3,239	5,374	7,589
Earnings as defined	$442,715	$134,159	$67,185	$537,354	$214,550	$298,531
FIXED CHARGES AS DEFINED IN REGULATION S-K:						
Interest on long-term debt	$ 85,220	$ 77,205	$14,234	$ 92,314	$ 87,681	$ 80,840
Other interest expense	9,879	9,427	1,080	(2,643)	1,691	3,351
Subsidiary's preferred stock dividend requirements	10,700	9,095	1,605	10,694	5,347	--
Interest element of rentals charged to income (a)	6,229	3,913	124	3,239	5,374	7,589
Fixed charges as defined	$112,028	$ 99,640	$17,043	$103,604	$100,093	$ 91,780
CONSOLIDATED RATIO OF EARNINGS TO FIXED CHARGES	3.95	1.35	3.94	5.19	2.14	3.25

(a) Includes the interest element of rentals where determinable plus 1/3 of rental expense where no readily defined interest element can be determined.

EXHIBIT 12.6
Page 2

JERSEY CENTRAL POWER & LIGHT COMPANY

CONSOLIDATED RATIO OF EARNINGS TO FIXED CHARGES PLUS PREFERRED STOCK DIVIDEND REQUIREMENTS (PRE-INCOME TAX BASIS)

	Year Ended December 31,	Jan. 1-	Nov. 7-	Year Ended December 31,		
	2000	Nov. 6, 2001	Dec. 31, 2001	2002	2003	2004
			(Dollars in thousands)			
EARNINGS AS DEFINED IN REGULATION S-K:						
Income before extraordinary items	$210,812	$ 34,467	$30,041	$251,895	$ 68,017	$111,639
Interest and other charges, before reduction for amounts capitalized	105,799	95,727	16,919	100,365	94,719	84,191
Provision for income taxes	119,875	52	20,101	181,855	46,440	95,112
Interest element of rentals charged to income (a)	6,229	3,913	124	3,239	5,374	7,589
Earnings as defined	$442,715	$134,159	$67,185	$537,354	$214,550	$298,531
FIXED CHARGES AS DEFINED IN REGULATION S-K PLUS PREFERRED STOCK DIVIDEND REQUIREMENTS (PRE-INCOME TAX BASIS):						
Interest on long-term debt	$ 85,220	$ 77,205	$14,234	$ 92,314	$ 87,681	$ 80,840
Other interest expense	9,879	9,427	1,080	(2,643)	1,691	3,351
Preferred stock dividend requirements	17,604	13,642	2,303	9,230	5,235	500
Adjustments to preferred stock dividends to state on a pre-income tax basis	3,928	7	467	(1,057)	(77)	426
Interest element of rentals charged to income (a)	6,229	3,913	124	3,239	5,374	7,589
Fixed charges as defined plus preferred stock dividend requirements (pre-income tax basis)	$122,860	$104,194	$18,208	$101,083	$ 99,904	$ 92,706
CONSOLIDATED RATIO OF EARNINGS TO FIXED CHARGES PLUS PREFERRED STOCK DIVIDEND REQUIREMENTS (PRE-INCOME TAX BASIS	3.60	1.29	3.69	5.32	2.15	3.22

(a) Includes the interest element of rentals where determinable plus 1/3 of rental expense where no readily defined interest element can be determined.

EXHIBIT 12.7
Page 1

METROPOLITAN EDISON COMPANY

CONSOLIDATED RATIO OF EARNINGS TO FIXED CHARGES

	Year Ended December 31, 2000	Jan. 1- Nov. 6, 2001	Nov. 7- Dec. 31, 2001	Year Ended December 31, 2002	2003	2004
			(Dollars in thousands)			
EARNINGS AS DEFINED IN REGULATION S-K:						
Income before extraordinary items	$ 81,895	$ 62,381	$14,617	$ 63,224	$ 60,953	$ 66,955
Interest and other charges, before reduction for amounts capitalized	55,181	48,568	8,461	50,969	46,277	45,057
Provision for income taxes	44,088	39,449	10,905	44,372	44,006	38,217
Interest element of rentals charged to income (a)	1,543	284	(693)	515	437	1,401
Earnings as defined	$182,707	$150,682	$33,290	$159,080	$151,673	$151,630
FIXED CHARGES AS DEFINED IN REGULATION S-K:						
Interest on long-term debt	$ 37,886	$ 33,101	$ 5,615	$ 40,774	$ 36,657	$ 40,630
Other interest expense	10,639	9,219	1,744	2,636	5,841	4,427
Subsidiary's preferred stock dividend requirements	6,656	6,248	1,102	7,559	3,779	--
Interest element of rentals charged to income (a)	1,543	284	(693)	515	437	1,401
Fixed charges as defined	$ 56,724	$ 48,852	$ 7,768	$ 51,484	$ 46,714	$ 46,458
CONSOLIDATED RATIO OF EARNINGS TO FIXED CHARGES	3.22	3.08	4.29	3.09	3.25	3.26

(a) Includes the interest element of rentals where determinable plus 1/3 of rental expense where no readily defined interest element can be determined.

METROPOLITAN EDISON COMPANY

CONSOLIDATED RATIO OF EARNINGS TO FIXED CHARGES PLUS PREFERRED STOCK DIVIDEND REQUIREMENTS (PRE-INCOME TAX BASIS)

	Year Ended December 31, 2000	Jan. 1- Nov. 6, 2001	Nov. 7- Dec. 31, 2001	Year Ended December 31, 2002	2003	2004
			(Dollars in thousands)			
EARNINGS AS DEFINED IN REGULATION S-K:						
Income before extraordinary items	$ 81,895	$ 62,381	$14,617	$ 63,224	$ 60,953	$ 66,955
Interest and other charges, before reduction for amounts capitalized	55,181	48,568	8,461	50,969	46,277	45,057
Provision for income taxes	44,088	39,449	10,905	44,372	44,006	38,217
Interest element of rentals charged to income	1,543	284	(693)	515	437	1,401
Earnings as defined	$182,707	$150,682	$33,290	$159,080	$151,673	$151,630
FIXED CHARGES AS DEFINED IN REGULATION S-K PLUS PREFERRED STOCK DIVIDEND REQUIREMENTS (PRE-INCOME TAX BASIS):						
Interest on long-term debt	$ 37,886	$ 33,101	$ 5,615	$ 40,774	$ 36,657	$ 40,630
Other interest expense	10,639	9,219	1,744	2,636	5,841	4,427
Preferred stock dividend requirements	6,656	6,248	1,102	7,559	3,779	--
Adjustments to preferred stock dividends to state on a pre-income tax basis	--	--	--	--	--	--
Interest element of rentals charged to income (a)	1,543	284	(693)	515	437	1,401
Fixed charges as defined plus preferred stock dividend requirements (pre-income tax basis)	$ 56,724	$ 48,852	$ 7,768	$ 51,484	$ 46,714	$ 46,458
CONSOLIDATED RATIO OF EARNINGS TO FIXED CHARGES PLUS PREFERRED STOCK DIVIDEND REQUIREMENTS (PRE-INCOME TAX BASIS)	3.22	3.08	4.29	3.09	3.25	3.26

(a) Includes the interest element of rentals where determinable plus 1/3 of rental expense where no readily defined interest element can be determined.

EXHIBIT 12.8
Page 1

PENNSYLVANIA ELECTRIC COMPANY

CONSOLIDATED RATIO OF EARNINGS TO FIXED CHARGES

	Year Ended December 31, 2000	Jan. 1- Nov. 6, 2001	Nov. 7- Dec. 31, 2001	Year Ended December 31, 2002	2003	2004
			(Dollars in thousands)			
EARNINGS AS DEFINED IN REGULATION S-K:						
Income before extraordinary items	$ 39,250	$23,718	$10,795	$ 50,910	$ 20,237	$ 36,030
Interest and other charges, before reduction for amounts capitalized	48,544	40,998	7,052	42,373	37,660	40,022
Provision for income taxes	29,754	19,402	8,231	34,248	24,836	30,001
Interest element of rentals charged to income(a)	3,020	891	311	1,849	3,076	3,016
Earnings as defined	$120,568	$85,009	$26,389	$129,380	$ 85,809	$109,069
FIXED CHARGES AS DEFINED IN REGULATION S-K:						
Interest on long-term debt	$ 29,964	$28,751	$ 3,972	$ 31,758	$ 29,565	$ 30,029
Other interest expense	11,546	6,008	1,979	3,061	4,318	9,993
Subsidiary's preferred stock dividend requirements	7,034	6,239	1,101	7,554	3,777	--
Interest element of rentals charged to income (a)	3,020	891	311	1,849	3,076	3,016
Fixed charges as defined	$ 51,564	$41,889	$ 7,363	$ 44,222	$ 40,736	$ 43,038
CONSOLIDATED RATIO OF EARNINGS TO FIXED CHARGES	2.34	2.03	3.58	2.93	2.11	2.53

(a) Includes the interest element of rentals where determinable plus 1/3 of rental expense where no readily defined interest element can be determined.

PENNSYLVANIA ELECTRIC COMPANY

CONSOLIDATED RATIO OF EARNINGS TO FIXED CHARGES PLUS PREFERRED STOCK DIVIDEND REQUIREMENTS (PRE-INCOME TAX BASIS)

	Year Ended December 31, 2000	Jan. 1- Nov. 6, 2001	Nov. 7- Dec. 31, 2001	Year Ended December 31, 2002	2003	2004
			(Dollars in thousands)			
EARNINGS AS DEFINED IN REGULATION S-K:						
Income before extraordinary items	$ 39,250	$23,718	$10,795	$ 50,910	$ 20,237	$ 36,030
Interest and other charges, before reduction for amounts capitalized	48,544	40,998	7,052	42,373	37,660	40,022
Provision for income taxes	29,754	19,402	8,231	34,248	24,836	30,001
Interest element of rentals charged to income (a)	3,020	891	311	1,849	3,076	3,016
Earnings as defined	$120,568	$85,009	$26,389	$129,380	$ 85,809	$109,069
FIXED CHARGES AS DEFINED IN REGULATION S-K PLUS PREFERRED STOCK DIVIDEND REQUIREMENTS (PRE-INCOME TAX BASIS):						
Interest on long-term debt	$ 29,964	$28,751	$ 3,972	$ 31,758	$ 29,565	$ 30,029
Other interest expense	11,546	6,008	1,979	3,061	4,318	9,993
Preferred stock dividend requirements	7,034	6,239	1,101	7,554	3,777	--
Adjustments to preferred stock dividends to state on a pre-income tax basis	--	--	--	--	--	--
Interest element of rentals charged to income (a)	3,020	891	311	1,849	3,076	3,016
Fixed charges as defined plus preferred stock dividend requirements (pre-income tax basis)	$ 51,564	$41,889	$ 7,363	$ 44,222	$ 40,736	$ 43,038
CONSOLIDATED RATIO OF EARNINGS TO FIXED CHARGES PLUS PREFERRED STOCK DIVIDEND REQUIREMENTS (PRE-INCOME TAX BASIS)	2.34	2.03	3.58	2.93	2.11	2.53

(a) Includes the interest element of rentals where determinable plus 1/3 of rental expense where no readily defined interest element can be determined.

EXHIBIT 23

FIRSTENERGY CORP.

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statements on Form S-3 (No. 333-48587, 333-102074 and 333-103865) and Form S-8 (No. 333-48651, 333-56094, 333-58279, 333-67798, 333-72764, 333-72766, 333-72768, 333-75985, 333-81183, 333-89356, 333-101472 and 333-110662) of FirstEnergy Corp. of our report dated March 7, 2005 relating to the consolidated financial statements, management's assessment of the effectiveness of internal control over financial reporting and the effectiveness of internal control over financial reporting, which appears in the Annual Report to Stockholders, which is incorporated in this Annual Report on Form 10-K. We also consent to the incorporation by reference of our report dated March 7, 2005 relating to the financial statement schedules, which appears in this Form 10-K.

PricewaterhouseCoopers LLP

Cleveland, Ohio
March 7, 2005

EXHIBIT 23.1

OHIO EDISON COMPANY

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statements on Form S-3 (No. 33-49413, 33-51139, 333-01489 and 333-05277) of Ohio Edison Company of our report dated March 7, 2005 relating to the consolidated financial statements, management's assessment of the effectiveness of internal control over financial reporting and the effectiveness of internal control over financial reporting, which appears in the Annual Report to Stockholders, which is incorporated in this Annual Report on Form 10-K. We also consent to the incorporation by reference of our report dated March 7, 2005 relating to the financial statement schedules, which appears in this Form 10-K.

PricewaterhouseCoopers LLP

Cleveland, Ohio
March 7, 2005

EXHIBIT 23.2

PENNSYLVANIA POWER COMPANY

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statements on Form S-3 (No. 33-62450 and 33-65156) of Pennsylvania Power Company of our report dated March 7, 2005 relating to the consolidated financial statements, management's assessment of the effectiveness of internal control over financial reporting and the effectiveness of internal control over financial reporting, which appears in the Annual Report to Stockholders, which is incorporated in this Annual Report on Form 10-K. We also consent to the incorporation by reference of our report dated March 7, 2005 relating to the financial statement schedules, which appears in this Form 10-K.

PricewaterhouseCoopers LLP

Cleveland, Ohio
March 7, 2005

EXHIBIT 23.3

PENNSYLVANIA ELECTRIC COMPANY

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statements on Form S-3 (No. 333-62295, 333-62295-01 and 333-62295-02) of Pennsylvania Electric Company of our report dated March 7, 2005 relating to the consolidated financial statements, management's assessment of the effectiveness of internal control over financial reporting and the effectiveness of internal control over financial reporting, which appears in the Annual Report to Stockholders, which is incorporated in this Annual Report on Form 10-K. We also consent to the incorporation by reference of our report dated March 7, 2005 relating to the financial statement schedules, which appears in this Form 10-K.

PricewaterhouseCoopers LLP

Cleveland, Ohio
March 7, 2005

Exhibit 31.1

Certification

I, Anthony J. Alexander, certify that:

1. I have reviewed this annual report on Form 10-K of FirstEnergy Corp., Ohio Edison Company, The Cleveland Electric Illuminating Company, The Toledo Edison Company, Pennsylvania Power Company, Metropolitan Edison Company and Pennsylvania Electric Company;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of each registrant as of, and for, the periods presented in this annual report;

4. Each registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f) for such registrant and we have:

   a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to such registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

   b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

   c) evaluated the effectiveness of such registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) disclosed in this report any change in such registrant's internal control over financial reporting that occurred during such registrant's most recent fiscal year that has materially affected, or is reasonably likely to materially affect, such registrant's internal control over financial reporting; and

5. Each registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to such registrant's auditors and the audit committee of such registrant's board of directors (or persons performing the equivalent function):

   a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect such registrant's ability to record, process, summarize and report financial data; and

   b) any fraud, whether or not material, that involves management or other employees who have a significant role in such registrant's internal control over financial reporting.

Date: March 9, 2005

/s/ Anthony J. Alexander
Anthony J. Alexander
Chief Executive Officer

Exhibit 31.2

Certification

I, Richard H. Marsh, certify that:

1. I have reviewed this annual report on Form 10-K of FirstEnergy Corp., Ohio Edison Company, The Cleveland Electric Illuminating Company, The Toledo Edison Company, Pennsylvania Power Company, Jersey Central Power & Light Company, Metropolitan Edison Company and Pennsylvania Electric Company;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of each registrant as of, and for, the periods presented in this annual report;

4. Each registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f) for such registrant and we have:

   a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to such registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

   b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

   c) evaluated the effectiveness of such registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) disclosed in this report any change in such registrant's internal control over financial reporting that occurred during such registrant's most recent fiscal year that has materially affected, or is reasonably likely to materially affect, such registrant's internal control over financial reporting; and

5. Each registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to such registrant's auditors and the audit committee of such registrant's board of directors (or persons performing the equivalent function):

   a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect such registrant's ability to record, process, summarize and report financial data; and

   b) any fraud, whether or not material, that involves management or other employees who have a significant role in such registrant's internal control over financial reporting.

Date: March 9, 2005

/s/ Richard H. Marsh
Richard H. Marsh
Chief Financial Officer

Exhibit 31.3

Certification

I, Stephen E. Morgan, certify that:

1. I have reviewed this annual report on Form 10-K of Jersey Central Power & Light Company;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f) for the registrant and we have:

   a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

   b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

   c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) disclosed in this report any change in such registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal year that has materially affected, or is reasonably likely to materially affect, such registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent function):

   a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial data; and

   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

March 9, 2005

/s/ Stephen E. Morgan
Stephen E. Morgan
Chief Executive Officer

Exhibit 32.1

CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350

In connection with the Annual Reports of FirstEnergy Corp., Ohio Edison Company, The Cleveland Electric Illuminating Company, The Toledo Edison Company, Pennsylvania Power Company, Metropolitan Edison Company, and Pennsylvania Electric Company ("Companies") on Form 10-K for the year ending December 31, 2004 as filed with the Securities and Exchange Commission on the date hereof (the "Reports"), each undersigned officer of each of the Companies does hereby certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that to the best of his knowledge:

(1) Each of the Reports fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in each of the Reports fairly presents, in all material respects, the financial condition and results of operations of the Company to which it relates.

/s/ Anthony J. Alexander
Anthony J. Alexander
Chief Executive Officer
March 9, 2005

/s/ Richard H. Marsh
Richard H. Marsh
Chief Financial Officer
March 9, 2005

Exhibit 32.2

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350

In connection with the Annual Report of Jersey Central Power & Light Company ("Company") on Form 10-K for the year ending December 31, 2004 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), each undersigned officer of the Company does hereby certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that to the best of his knowledge:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Stephen E. Morgan
Stephen E. Morgaqn
President
(Chief Executive Officer)
March 9, 2005

/s/ Richard H. Marsh
Richard H. Marsh
Chief Financial Officer
March 9, 2005

FirstEnergy®

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2004 Form 10-K