CLEVELAND ELECTRIC ILLUMINATING CO
Form 10-Q/A
August 19, 2003

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D. C. 20549

FORM 10-Q/A

AMENDMENT NO. 1

(MARK ONE)

[X] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

FOR THE QUARTERLY PERIOD ENDED MARCH 31, 2003

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) 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 TELEPHONE (800)736-3402	34-4375005

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

Yes X No

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

CLASS	OUTSTANDING AS OF MAY 9, 2003
FirstEnergy Corp., $.10 par value	297,636,276
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

FirstEnergy Corp. is the sole holder of Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company.

This combined Form 10-Q/A is separately filed by FirstEnergy Corp., Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison 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 FirstEnergy subsidiary registrants is also attributed to FirstEnergy.

This Form 10-Q/A 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. This Form 10-Q 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), availability and cost of capital, inability of the Davis-Besse Nuclear Power Station to restart (including because of an inability to obtain a favorable final determination from the Nuclear Regulatory Commission) in the fall of 2003, inability to accomplish or realize anticipated benefits from strategic goals, further investigation into the causes of the August 14, 2003, power outage, and other similar factors.

EXPLANATORY NOTE

This Amendment No. 1 for FirstEnergy Corp., Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company is being filed to restate certain amounts in the consolidated financial statements for three months ended March 31, 2002 and 2003.

As described in Note 1 to the consolidated financial statements of FirstEnergy Corp., Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company, the Registrants have restated their financial statements to reflect a change in the method of amortizing the costs associated with the Ohio transition plan and recognition of above-market values of certain leased generation facilities

These restatements have resulted in a decrease in net income of $22.5 million, $0.1 million, $5.0 million and $4.5 million reported for FirstEnergy Corp., Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company, respectively, for the three months ended March 31, 2003. Net income as reported for the three months ended March 31, 2002 increased $1.8 million, $10.3 million $2.2 million and $1.0 million for FirstEnergy Corp., Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company, respectively.

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PART II. OTHER INFORMATION

PART I. FINANCIAL INFORMATION

FIRSTENERGY CORP. AND SUBSIDIARIES
OHIO EDISON COMPANY AND SUBSIDIARIES
THE CLEVELAND ELECTRIC ILLUMINATING COMPANY AND SUBSIDIARIES
THE TOLEDO EDISON COMPANY AND SUBSIDIARY

NOTES TO FINANCIAL STATEMENTS
(UNAUDITED)

1 - FINANCIAL STATEMENTS:

The principal business of FirstEnergy Corp. (FirstEnergy) is the holding, directly or indirectly, of all of the outstanding common stock of its eight principal electric utility operating subsidiaries, Ohio Edison Company (OE), The Cleveland Electric Illuminating Company (CEI), The Toledo Edison Company (TE), Pennsylvania Power Company (Penn), American Transmission Systems, Inc. (ATSI), Jersey Central Power & Light Company (JCP&L), Metropolitan Edison Company (Met-Ed) and Pennsylvania Electric Company (Penelec). These utility subsidiaries are referred to throughout as "Companies." Penn is a wholly owned subsidiary of OE. JCP&L, Met-Ed and Penelec were acquired in a merger (which was effective November 7, 2001) with GPU, Inc., the former parent company of JCP&L, Met-Ed and Penelec. The merger was accounted for by the purchase method of accounting and the applicable effects were reflected on the financial statements of JCP&L, Met-Ed and Penelec as of the merger date. FirstEnergy's consolidated financial statements also include its other principal subsidiaries: FirstEnergy Solutions Corp. (FES); FirstEnergy Facilities Services Group, LLC (FSG); MYR Group, Inc. (MYR); MARBEL Energy Corporation; FirstEnergy Nuclear Operating Company (FENOC); GPU Capital, Inc.; GPU Power, Inc.; FirstEnergy Service Company (FECO); and GPU Service, Inc. (GPUS). FES provides energy-related products and services and, through its FirstEnergy Generation Corp. (FGCO) subsidiary, operates FirstEnergy's nonnuclear generation business. FENOC operates the Companies' nuclear generating facilities. FSG is the parent company of several heating, ventilating, air conditioning and energy management companies, and MYR is a utility infrastructure construction service company. MARBEL is a fully integrated natural gas company. GPU Capital owns and operates electric distribution systems in foreign countries (see Note 3) and GPU Power owns and operates generation facilities in foreign countries. FECO and GPUS provide legal, financial and other corporate support services to affiliated FirstEnergy companies. Significant intercompany transactions have been eliminated.

The Companies follow the accounting policies and practices prescribed by the Securities and Exchange Commission (SEC), the Public Utilities Commission of Ohio (PUCO), the Pennsylvania Public Utility Commission (PPUC), the New Jersey Board of Public Utilities (NJBPU) and the Federal Energy Regulatory Commission (FERC). The condensed unaudited financial statements of

FirstEnergy and each of the Companies reflect all normal recurring adjustments that, in the opinion of management, are necessary to fairly present results of operations for the interim periods. These statements should be read in conjunction with the financial statements and notes included in the combined Annual Report on Form 10-K and Amendments Nos. 1 and 2 on Forms 10-K/A for the year ended December 31, 2002 for FirstEnergy and the Companies. The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make periodic estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses and disclosure of contingent assets and liabilities. Actual results could differ from those estimates. The reported results of operations are not indicative of results of operations for any future period. Certain prior year amounts have been reclassified to conform with the current year presentation, as discussed further in Note 5.

Preferred Securities

The sole assets of the CEI subsidiary trust that is the obligor on the preferred securities included in FirstEnergy's and CEI's Capitalizations are $103.1 million aggregate principal amount of 9% junior subordinated debentures of CEI due December 31, 2006. CEI has effectively provided a full and unconditional guarantee of the trust's obligations under the preferred securities.

Met-Ed and Penelec each formed statutory business trusts for the issuance of $100 million each of preferred securities due 2039 and included in FirstEnergy's, Met-Ed's and Penelec's respective Capitalizations. Ownership of the respective Met-Ed and Penelec trusts is through separate wholly-owned limited partnerships, of which a wholly-owned subsidiary of each company is the sole general partner. In these transactions, the sole assets and sources of revenues of each trust are the preferred securities of the applicable limited partnership, whose sole assets are the 7.35% and 7.34% subordinated debentures (aggregate principal amount of $103.1 million each) of Met-Ed and Penelec, respectively. In each case, the applicable parent company has effectively provided a full and unconditional guarantee of the trust's obligations under the preferred securities.

Securitized Transition Bonds

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

JCP&L does not own or did not purchase any of the transition bonds, which are included in long-term debt on FirstEnergy's and JCP&L's Consolidated Balance Sheet. The transition bonds represent obligations only of the Issuer and are collateralized solely by the equity and assets of the Issuer, which consist primarily of bondable transition property. The bondable transition property is solely the property of the Issuer.

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

quarterly servicing fee of $100,000 that is payable from transition bond charge collections.

Derivative Accounting

FirstEnergy is exposed to financial risks resulting from the fluctuation of interest rates and commodity prices, including electricity, natural gas and coal. To manage the volatility relating to these exposures, FirstEnergy uses a variety of non-derivative and derivative instruments, including forward contracts, options, futures contracts and swaps. The derivatives are used principally for hedging purposes, and to a lesser extent, for trading purposes. FirstEnergy's Risk Policy Committee, comprised of executive officers, exercises an independent risk oversight function to ensure compliance with corporate risk management policies and prudent risk management practices.

FirstEnergy uses derivatives to hedge the risk of price and interest rate fluctuations. FirstEnergy's primary ongoing hedging activity involves cash flow hedges of electricity and natural gas purchases. The maximum periods over which the variability of electricity and natural gas cash flows are hedged are two and three years, respectively. Gains and losses from hedges of commodity price risks are included in net income when the underlying hedged commodities are delivered. Also, gains and losses are included in net income when ineffectiveness occurs on certain natural gas hedges. FirstEnergy entered into interest rate derivative transactions during 2001 to hedge a portion of the anticipated interest payments on debt related to the GPU acquisition. Gains and losses from hedges of anticipated interest payments on acquisition debt will be included in net income over the periods that hedged interest payments are made - 5, 10 and 30 years. Gains and losses from derivative contracts are included in other operating expenses. The current net deferred loss of $105.8 million included in Accumulated Other Comprehensive Loss (AOCL) as of March 31, 2003, for derivative hedging activity, as compared to the December 31, 2002 balance of $110.2 million in net deferred losses, resulted from a $8.8 million reduction related to current hedging activity and a $4.4 million increase due to net hedge gains included in earnings during the three months ended March 31, 2003. Approximately $20.2 million (after tax) of the current net deferred loss on derivative instruments in AOCL is expected to be reclassified to earnings during the next twelve months as hedged transactions occur. However, the fair value of these derivative instruments will fluctuate from period to period based on various market factors and will generally be more than offset by the margin on related sales and revenues. FirstEnergy also entered into fixed-to-floating interest rate swap agreements during 2002 to increase the variable-rate component of its debt portfolio. These derivatives are treated as fair value hedges of fixed-rate, long-term debt issues-protecting against the risk of changes in the fair value of fixed-rate debt instruments due to lower interest rates. Swap maturities, call options and interest payment dates match those of the underlying obligations resulting in no ineffectiveness in these hedge positions. The swap agreements consummated in the first quarter of 2003 are based on a notional principal amount of $200 million. As of March 31, 2003, the notional amount of FirstEnergy's fixed-for-floating rate interest rate swaps totaled $700 million.

FirstEnergy engages in the trading of commodity derivatives and periodically experiences net open positions. FirstEnergy's risk management policies limit the exposure to market risk from open positions and require daily reporting to management of potential financial exposures.

Comprehensive Income

Comprehensive income includes net income as reported on the Consolidated Statements of Income and all other changes in common stockholders' equity, except those resulting from transactions with common stockholders. As of

March 31, 2003, FirstEnergy's AOCL was approximately $657.4 million as compared to the December 31, 2002 balance of $656.1 million. Comprehensive income for the first quarter of 2003 and 2002 are shown in the following table:

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	THREE MONTHS ENDED MARCH 31,	
	2003	2002
	RESTATED (SEE NOTE 1)	RESTATED (SEE NOTE 1)
	(IN THOUSANDS)	
Net income	$ 218,502	$ 118,268
Other comprehensive income, net of tax:		
Derivative hedge transactions	4,341	35,844
All other	1,484	730
Comprehensive income	$ 224,327	$ 154,842

Stock-Based Compensation

FirstEnergy applies the recognition and measurement principles of Accounting Principles Board (APB) Opinion No. 25 (APB 25), "Accounting for Stock Issued to Employees" and related Interpretations in accounting for its stock-based compensation plans. No material stock-based employee compensation expense is reflected in net income as all options granted under those plans have exercise prices equal to the market value of the underlying common stock on the respective grant dates, resulting in substantially no intrinsic value.

If FirstEnergy had accounted for employee stock options under the fair value method, a higher value would have been assigned to the options granted. The effects of applying fair value accounting to FirstEnergy's stock options would be to reduce net income and earnings per share. The following table summarizes this effect.

	THREE MONTHS ENDED MARCH 31,	
	2003	2002
	RESTATED (SEE NOTE 1)	RESTATED (SEE NOTE 1)
	(IN THOUSANDS)	

Net Income, as reported	$ 218,502	$ 118,268
Add back compensation expense reported in net income, net of tax (based on APB 25)	43	43
Deduct compensation expense based upon fair value, net of tax	(2,983)	(1,402)
Adjusted net income	$ 215,562	$ 116,909
Earnings Per Share of Common Stock -		
Basic		
As Reported	$ 0.74	$ 0.40
Adjusted	$ 0.73	$ 0.40
Diluted		
As Reported	$ 0.74	$ 0.40
Adjusted	$ 0.73	$ 0.40

Change in Previously Reported Income Statement Classification -

FirstEnergy recorded an increase to income during the three months ended March 31, 2002 of $31.7 million (net of income taxes of $13.6 million) relative to a decision to retain an interest in the Avon Energy Partners Holdings (Avon) business previously classified as held for sale - see Note 3. This amount represents the aggregate results of operations of Avon for the period this business was held for sale. It was previously reported on the Consolidated Statement of Income as the cumulative effect of a change in accounting. In April 2003, it was determined that this amount should instead have been classified in operations. As further discussed in Note 3, the decision to retain Avon was made in the first quarter of 2002 and Avon's results of operations for that quarter have been classified in their respective revenue and expense captions on the Consolidated Statement of Income. This change in classification had no effect on previously reported net income. The effects of this change on the Consolidated Statement of Income previously reported for the three months ended March 31, 2002 are reflected in the restatements shown below.

RESTATEMENTS OF PREVIOUSLY REPORTED RESULTS

FirstEnergy, OE, CEI and TE have restated their financial statements for the year ended December 31, 2002 and for the three months ended March 31, 2003 and 2002. The primary modifications include revisions to reflect a change in the method of amortizing costs being recovered through the Ohio transition plan and recognition of above-market values of certain leased generation facilities. In addition, certain other immaterial adjustments recorded in the first quarter of 2003 that related to prior periods are now reported in results for the earlier periods. The net impact of these adjustments increases net income by $6.2 million in the first quarter of 2003. Included in the adjustments are the impact in the first quarter ended March 31, 2002 of recognizing a reserve on the deferred costs incurred subsequent to the merger associated with this Company's rate matter in Pennsylvania (see note 4). The impact of this restatement increased net income in the first quarter ended March 31, 2002 by $12 million. See Note 2(M) of the FirstEnergy, OE, CEI, and TE Form 10-K/A for further discussion of the restatements.

Transition Cost Amortization

As discussed in Regulatory Matters in Note 4, FirstEnergy, OE, CEI and TE amortize transition costs using the effective interest method. The amortization schedules originally developed at the beginning of the transition plan in 2001 in applying this method were based on total transition revenues, including revenues designed to recover costs which have not yet been incurred or that were recognized on the regulatory financial statements (fair value purchase accounting adjustments) but not in the financial statements prepared under GAAP. The Ohio electric utilities have revised the amortization schedules under the effective interest method to consider only revenues relating to transition regulatory assets recognized on the GAAP balance sheet. The impact of this change will result in higher amortization of these regulatory assets in the first several years of the transition cost recovery period, compared with the method previously applied. The change in method results in no change in total amortization of the regulatory assets recovered under the transition plan through the end of 2009.

The following table summarizes the previously reported transition cost amortization and the restated amounts under the revised method for the three months ended March 31, 2002 and 2003:

	Three Months Ended March 31, 2002		Three Months Ended March 31, 2003	
	AS PREVIOUSLY REPORTED	AS RESTATED	AS PREVIOUSLY REPORTED	AS RESTATED
OE	$ 76,176	$ 68,176	$ 98,927	$101,927
CEI	13,141	37,141	16,802	41,602
TE	7,892	24,292	13,023	28,423
Total FirstEnergy	$ 97,209	$129,609	$128,752	$171,952

Above-Market Lease Costs

In 1997, FirstEnergy Corp. was formed through a merger between OE and Centerior Energy Corp. The merger was accounted for as an acquisition of Centerior, the parent company of CEI and TE, under the purchase accounting rules of Accounting Principles Board (APB) Opinion No. 16. In connection with the reassessment of the accounting for the transition plan, FirstEnergy reassessed its accounting for the Centerior purchase and determined that above market lease liabilities should have been recorded at the time of the merger. Accordingly, as of 2002, FirstEnergy recorded additional adjustments associated with the 1997 merger between OE and Centerior to reflect certain above market lease liabilities for Beaver Valley Unit 2 and the Bruce Mansfield Plant, for which CEI and TE had previously entered into sale-leaseback arrangements. CEI and TE recorded an increase in goodwill related to the above market lease costs for Beaver Valley Unit 2 since regulatory accounting for nuclear generating assets had been discontinued prior to the merger date and it was determined that this additional liability would have increased goodwill at the date of the merger. The corresponding impact of the above market lease liabilities for the Bruce Mansfield Plant was recorded as a regulatory asset because regulatory accounting had not been discontinued at that time for the fossil generating assets and recovery of these liabilities was provided for under the transition plan.

The total above market lease obligation of $722 million (CEI $ 611 million, TE $111 million) associated with Beaver Valley Unit 2 will be amortized

through the end of the lease term in 2017. The additional goodwill has been recorded on a net basis, reflecting amortization that would have been recorded through 2001 when goodwill amortization ceased with the adoption of Statement of Financial Accounting Standard (SFAS) No. 142 (SFAS 142). The total above market lease obligation of $755 million (CEI $457 million, TE $298 million) associated with the Bruce Mansfield Plant is being amortized through the end of 2016. Before the start of the transition plan in 2001, the regulatory asset would have been amortized at the same rate as the lease obligation. Beginning in 2001, the remaining unamortized regulatory asset would have been included in CEI's and TE's amortization schedules for regulatory assets and amortized through the end of the recovery period - approximately 2009 for CEI and 2007 for TE.

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The effects of these changes and the change as described under "Change in Previously Reported Income Statement Classification" on the Consolidated Statements of Income previously reported for the three months ended March 31, 2003 and 2002 are as follows:

FIRSTENERGY

	THREE MONTHS ENDED MARCH 31, 2003		THREE MONTHS END MARCH 31, 2002	
	AS PREVIOUSLY REPORTED	AS RESTATED	AS PREVIOUSLY REPORTED	RE
	(IN THOUSANDS, EXCEPT PER SHARE AMOUNTS))			
Revenues	$ 3,244,472	$3,233,756	$ 2,853,278	$2,
Expenses	2,800,758	2,824,465	2,363,634	2,
Income before interest and income taxes	443,714	409,291	489,644	
Net interest charges	202,740	206,040	278,722	
Income taxes	102,136	93,773	94,429	
Income before discontinued operations and cumulative effect of accounting change	138,838	109,478	116,493	
Discontinued operations	--	6,877		
Cumulative effect of accounting change	102,147	102,147	--	
Net income	$ 240,985	$ 218,502	$ 116,493	$
Basic earnings per share of common stock	$ 0.82	$ 0.74	$ 0.40	$
Diluted earnings per share of common stock	$ 0.82	$ 0.74	$ 0.40	$

OE

	THREE MONTHS ENDED MARCH 31, 2003		THREE MONTHS EN MARCH 31, 200	
	AS PREVIOUSLY REPORTED	AS RESTATED	AS PREVIOUSLY REPORTED	RE

(IN THOUSANDS)

Revenues	$ 742,743	$ 742,743	$ 707,799	$
Expenses	673,054	672,661	610,735	
Operating income	69,689	70,082	97,064	
Other income	14,031	13,501	512	
Income before net interest charges	83,720	83,583	97,576	
Net interest charges	26,498	26,498	41,225	
Income before cumulative effect of accounting change	57,222	57,085	56,351	
Cumulative effect of accounting change	31,720	31,720	--	
Net income	88,942	88,805	56,351	
Preferred stock dividend requirements	659	659	2,596	
Earnings on common stock	$ 88,283	$ 88,146	$ 53,755	$

CEI

	THREE MONTHS ENDED MARCH 31, 2003		THREE MONTHS EN MARCH 31, 200	
	AS PREVIOUSLY REPORTED	AS RESTATED	AS PREVIOUSLY REPORTED	RE
	(IN THOUSANDS)			
Revenues	$ 419,771	$ 419,771	$ 424,977	$
Expenses	363,467	365,760	369,655	
Operating income	56,304	54,011	55,322	
Other income	4,741	4,741	5,241	
Income before net interest charges	61,045	58,752	60,563	
Net interest charges	40,754	43,454	47,867	
Income before cumulative effect of accounting change	20,291	15,298	12,696	
Cumulative effect of accounting change	42,378	42,378	--	
Net income	62,669	57,676	12,696	
Preferred stock dividend requirements	(759)	(759)	8,256	
Earnings(loss) attributable to common stock	$ 63,428	$ 58,435	$ 4,440	$

TE

	THREE MONTHS ENDED MARCH 31, 2003		THREE MONTHS EN MARCH 31, 20	
	AS PREVIOUSLY REPORTED	AS RESTATED	AS PREVIOUSLY REPORTED	RE
	(IN THOUSANDS)			
Revenues	$ 231,822	$ 231,822	$ 244,167	$
Expenses	221,195	226,345	234,509	
Operating income	10,627	5,477	9,658	
Other income	3,100	3,100	4,343	
Income before net interest charges	13,727	8,577	14,001	
Net interest charges	10,677	9,977	14,709	
Income (loss) before cumulative effect of accounting change	3,050	(1,400)	(708)	
Cumulative effect of accounting change	25,550	25,550	--	
Net income (loss)	28,600	24,150	(708)	
Preferred stock dividend requirements	1,605	2,205	4,724	
Earnings(loss) attributable to common stock	$ 26,995	$ 21,945	$ (5,432)	$

The effects of these changes on the Consolidated Statements of Cash Flows previously reported for the three months ended March 31, 2003 and 2002, are as follows:

FE

	THREE MONTHS ENDED MARCH 31, 2003		THREE MONTHS END MARCH 31, 200	
	AS PREVIOUSLY REPORTED	AS RESTATED	AS PREVIOUSLY REPORTED	RE
	(IN THOUSANDS)			
CASH FLOWS FROM OPERATING ACTIVITIES				
Net income	$ 240,985	$ 218,502	$ 116,493	$
Adjustments to reconcile net income to net cash from operating activities:				
Provision for depreciation and amortization	281,662	324,862	262,828	
Nuclear fuel and lease amortization	14,918	14,918	20,965	
Other amortization	(4,613)	(4,613)	(3,537)	

Deferred costs recoverable as regulatory assets	(38,748)	(38,748)	(70,134)	
Deferred income taxes	40,619	31,352	(20,534)	
Investment tax credits	(6,259)	(6,259)	(6,746)	
Cumulative effect of accounting change (Note 5)	(174,663)	(174,663)	--	
Receivables	1,602	(1,898)	60,095	
Materials and supplies	11,413	11,413	18,163	
Accounts payable	(18,915)	(7,115)	(3,004)	
Accrued taxes	98,896	97,553	82,297	
Accrued interest	89,599	89,599	86,579	
Deferred rents & sale/leaseback	3,558	(17,592)	71,438	
Prepayments & other	(69,673)	(69,673)	109,551	
Other	(8,119)	(5,376)	(260,370)	(
Net cash provided from operating activities	$ 462,262	$ 462,262	$ 464,084	$

OE

	THREE MONTHS ENDED MARCH 31, 2003		THREE MONTHS EN MARCH 31, 200	
	AS PREVIOUSLY REPORTED	AS RESTATED	AS PREVIOUSLY REPORTED	RE
		(IN THOUSANDS)		
CASH FLOWS FROM OPERATING ACTIVITIES				
Net income	$ 88,942	$ 88,805	$ 56,351	$
Adjustments to reconcile net income to net cash from operating activities:				
Provision for depreciation and amortization	105,385	108,385	92,130	
Nuclear fuel and lease amortization	7,106	7,106	11,402	
Deferred income taxes	8,683	7,683	(13,170)	
Investment tax credits	(3,580)	(3,704)	(3,773)	
Cumulative effect of accounting change	(54,109)	(54,109)	--	
Receivables	(26,409)	(29,909)	64,148	
Materials and supplies	(1,298)	(1,298)	(1,642)	
Accounts payable	14,470	14,470	(18,295)	
Accrued taxes	4,478	6,051	56,884	
Accrued interest	2,437	2,437	6,237	
Deferred rents & sale/leaseback	31,683	31,683	31,683	
Prepayments & other	(14,893)	(14,893)	16,095	
Other	(9,378)	(9,190)	(30,539)	
Net cash provided from operating activities	$ 153,517	$ 153,517	$ 267,511	$

CEI

	THREE MONTHS ENDED MARCH 31, 2003		THREE MONTHS EN MARCH 31, 20	
	AS PREVIOUSLY REPORTED	AS RESTATED	AS PREVIOUSLY REPORTED	RE
	(IN THOUSANDS)			
CASH FLOWS FROM OPERATING ACTIVITIES				
Net income	$ 62,669	$ 57,676	$ 12,696	$
Adjustments to reconcile net income to net cash from operating activities:				
Provision for depreciation and amortization	26,557	51,357	28,471	
Nuclear fuel and lease amortization	5,044	5,044	5,990	
Other amortization	(4,613)	(4,613)	(3,892)	
Deferred income taxes	35,474	33,804	7,196	
Investment tax credits	(965)	(1,202)	(902)	
Receivables	15,242	15,242	6,816	
Materials and supplies	(128)	(128)	(1,366)	
Accounts payable	(44,129)	(44,129)	18,322	
Cumulative effect of accounting change	(72,547)	(72,547)	--	
Other	(17,784)	(35,684)	14,191	
Net cash provided from operating activities	$ 4,820	$ 4,820	$ 87,522	$

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	THREE MONTHS ENDED MARCH 31, 2003		THREE MONTHS EN MARCH 31, 200	
	AS PREVIOUSLY REPORTED	AS RESTATED	AS PREVIOUSLY REPORTED	RE
	(IN THOUSANDS)			
CASH FLOWS FROM OPERATING ACTIVITIES				
Net income	$ 28,600	$ 24,150	$ (708)	$
Adjustments to reconcile net income to net cash from operating activities:				
Provision for depreciation and amortization	20,240	35,640	21,368	

Nuclear fuel and lease amortization	2,768	2,768	3,573	
Deferred income taxes	22,675	19,130	5,314	
Investment tax credits	(498)	(514)	(486)	
Receivables	12,249	12,249	20,022	
Materials and supplies	(727)	(727)	(651)	
Accounts payable	(53,917)	(53,917)	2,861	
Cumulative effect of accounting change	(43,751)	(43,751)	--	
Other	(17,590)	(24,979)	14,472	
Net cash provided from (used for) operating activities	$ (29,951)	$ (29,951)	$ 65,765	$

2 - COMMITMENTS, GUARANTEES AND CONTINGENCIES:

Capital Expenditures

FirstEnergy's current forecast reflects expenditures of approximately $3.1 billion (OE-$268 million, CEI-$312 million, TE-$169 million, Penn-$123 million, JCP&L-$462 million, Met-Ed-$288 million, Penelec-$328 million, ATSI-$131 million, FES-$823 million and other subsidiaries-$147 million) for property additions and improvements from 2003-2007, of which approximately $727 million (OE-$86 million, CEI-$96 million, TE-$54 million, Penn-$53 million, JCP&L-$102 million, Met-Ed-$53 million, Penelec-$54 million, ATSI-$25 million, FES-$124 million and other subsidiaries-$80 million) is applicable to 2003. Investments for additional nuclear fuel during the 2003-2007 period are estimated to be approximately $485 million (OE-$55 million, CEI-$53 million, TE-$34 million, Penn-$42 million and FES-$301 million), of which approximately $69 million (OE-$23 million, CEI-$15 million, TE-$12 million and Penn-$19 million) applies to 2003.

Guarantees and Other Assurances

As part of normal business activities, FirstEnergy enters into various agreements on behalf of its subsidiaries to provide financial or performance assurances to third parties. Such agreements include contract guarantees, surety bonds and ratings contingent collateralization provisions. As of March 31, 2003, outstanding guarantees and other assurances aggregated $960.2 million.

FirstEnergy guarantees energy and energy-related payments of its subsidiaries involved in energy marketing activities - principally to facilitate normal physical transactions involving electricity, gas, emission allowances and coal. FirstEnergy also provides guarantees to various providers of subsidiary financing principally for the acquisition of property, plant and equipment. These agreements legally obligate FirstEnergy and its subsidiaries to fulfill the obligations of those subsidiaries directly involved in energy and energy-related transactions or financing where the law might otherwise limit the counterparties' claims. If demands of a counterparty were to exceed the ability of a subsidiary to satisfy existing obligations, FirstEnergy's guarantee enables the counterparty's legal claim to be satisfied by other FirstEnergy assets. The likelihood that such parental guarantees of $872.7 million as of March 31, 2003 will increase amounts otherwise to be paid by FirstEnergy to meet its obligations incurred in connection with financings and ongoing energy and energy-related activities is remote.

Most of FirstEnergy's surety bonds are backed by various indemnities common within the insurance industry. Surety bonds and related FirstEnergy guarantees of $25.8 million provide additional assurance to outside parties that contractual and statutory obligations will be met in a number of areas including

construction jobs, environmental commitments and various retail transactions.

Various energy supply contracts contain credit enhancement provisions in the form of cash collateral or letters of credit in the event of a reduction in credit rating below investment grade. These provisions vary and typically require more than one rating reduction to fall below investment grade by Standard & Poor's or Moody's Investors Service to trigger additional collateralization by FirstEnergy. As of March 31, 2003, rating-contingent collateralization totaled $61.7 million. FirstEnergy monitors these collateralization provisions and updates its total exposure monthly.

Environmental Matters

Various federal, state and local authorities regulate the Companies with regard to air and water quality and other environmental matters. FirstEnergy estimates additional capital expenditures for environmental compliance of approximately $159 million, which is included in the construction forecast provided under "Capital Expenditures" for 2003 through 2007.

The Companies are required to meet federally approved sulfur dioxide (SO2) regulations. Violations of such regulations can result in shutdown of the generating unit involved and/or civil or criminal penalties of up to $31,500 for each day the unit is in violation. The Environmental Protection Agency (EPA) has an interim enforcement policy for SO2 regulations in Ohio that allows for compliance based on a 30-day averaging period. The Companies cannot predict what action the EPA may take in the future with respect to the interim enforcement policy.

The Companies believe they are in compliance with the current SO2 and nitrogen oxides (NOx) reduction requirements under the Clean Air Act Amendments of 1990. SO2 reductions are being achieved by burning lower-sulfur fuel, generating more electricity from lower-emitting plants, and/or using emission allowances. NOx reductions are being achieved through combustion controls and the generation of more electricity at lower-emitting plants. In September 1998, the EPA finalized regulations requiring additional NOx reductions from the Companies' Ohio and Pennsylvania facilities. The EPA's NOx Transport Rule imposes uniform reductions of NOx emissions (an approximate 85% reduction in utility plant NOx emissions from projected 2007 emissions) across a region of nineteen states and the District of Columbia, including New Jersey, Ohio and Pennsylvania, based on a conclusion that such NOx emissions are contributing significantly to ozone pollution in the eastern United States. State Implementation Plans (SIP) must comply by May 31, 2004 with individual state NOx budgets established by the EPA. Pennsylvania submitted a SIP that requires compliance with the NOx budgets at the Companies' Pennsylvania facilities by May 1, 2003 and Ohio submitted a SIP that requires compliance with the NOx budgets at the Companies' Ohio facilities by May 31, 2004.

In July 1997, the EPA promulgated changes in the National Ambient Air Quality Standard (NAAQS) for ozone emissions and proposed a new NAAQS for previously unregulated ultra-fine particulate matter. In May 1999, the U.S. Court of Appeals for the D.C. Circuit found constitutional and other defects in the new NAAQS rules. In February 2001, the U.S. Supreme Court upheld the new NAAQS rules regulating ultra-fine particulates but found defects in the new NAAQS rules for ozone and decided that the EPA must revise those rules. The future cost of compliance with these regulations may be substantial and will depend if and how they are ultimately implemented by the states in which the Companies operate affected facilities.

In 1999 and 2000, the EPA issued Notices of Violation (NOV) or a Compliance Order to nine utilities covering 44 power plants, including the W. H. Sammis Plant. 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 for which hearings began in February 2003. The NOV and complaint allege violations of the Clean Air Act based on operation and maintenance of the 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. Although unable to predict the outcome of these proceedings, FirstEnergy believes the Sammis Plant is in full compliance with the Clean Air Act and the NOV and complaint are without merit. Penalties could be imposed if the Sammis Plant continues to operate without correcting the alleged violations and a court determines that the allegations are valid. The Sammis Plant continues to operate while these proceedings are pending.

In December 2000, the EPA announced it would proceed with the development of regulations regarding hazardous air pollutants from electric power plants. The EPA identified mercury as the hazardous air pollutant of greatest concern. The EPA established a schedule to propose regulations by December 2003 and issue final regulations by December 2004. The future cost of compliance with these regulations may be substantial.

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 has issued its final regulatory determination 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 "potentially responsible parties" (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 be held liable on a joint and several basis. Therefore, potential environmental liabilities have been recognized on the Consolidated Balance Sheet as of March 31, 2003, 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

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societal benefits charge. The Companies have total accrued liabilities aggregating approximately $53.9 million (JCP&L-$47.1 million, CEI-$2.5 million, TE-$0.2 million, Met-Ed-$0.2 million, Penelec-$0.3 million and other-$3.6 million) as of March 31, 2003.

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 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. FirstEnergy believes it is in material compliance with existing regulations but is unable to predict whether environmental regulations will change and what, if any, the effects of such change would be.

Other Commitments and Contingencies

GPU made significant investments in foreign businesses and facilities through its GPU Capital and GPU Power subsidiaries. Although FirstEnergy attempts to mitigate its risks related to foreign investments, it faces additional risks inherent in operating in such locations, including foreign currency fluctuations.

EI Barranquilla, a wholly owned subsidiary of GPU Power, is a 28.67% equity investor in Termobarranquilla S.A., Empresa de Servicios Publicos (TEBSA), which owns a Colombian independent power generation project. GPU Power is committed through September 30, 2003, under certain circumstances, to make additional standby equity contributions to TEBSA of $21.3 million, which FirstEnergy has guaranteed. The total outstanding senior debt of the TEBSA project is $239 million as of March 31, 2003. The lenders include the Overseas Private Investment Corporation, US Export Import Bank and a commercial bank syndicate. FirstEnergy has also guaranteed the obligations of the operators of the TEBSA project, up to a maximum of $5.9 million (subject to escalation) under the project's operations and maintenance agreement. FirstEnergy provided the TEBSA project lenders a $50 million letter of credit (LOC) issued by Bank One under FirstEnergy's existing $250 million LOC capacity available as part of the $1.5 billion FirstEnergy credit facility to obtain TEBSA lender consent to abandon its Argentina operations, GPU Empresa Distribuidora Electrica Regional S.A. and affiliates (Emdersa) (see Note 3 below).

Legal Matters

Various lawsuits, claims and proceedings related to the FirstEnergy's normal business operations are pending against it and its subsidiaries. The most significant applicable to the Company are described above.

3 - DIVESTITURES:

INTERNATIONAL OPERATIONS-

FirstEnergy had identified certain former GPU international operations for divestiture within one year of the merger. These operations constitute individual "lines of business" as defined in APB Opinion (APB) No. 30, "Reporting the Results of Operations - Reporting the Effects of Disposal of a Segment of a Business, and Extraordinary, Unusual and Infrequently Occurring Events and Transactions," with physically and operationally separable activities. Application of Emerging Issues Task Force (EITF) Issue No. 87-11, "Allocation of Purchase Price to Assets to Be Sold," required that expected, pre-sale cash flows, including incremental interest costs on related acquisition debt, of these operations be considered part of the purchase price allocation. Accordingly, subsequent to the merger date, results of operations and incremental interest costs related to these international subsidiaries were not included in FirstEnergy's 2001 Consolidated Statement of Income. Additionally, assets and liabilities of these international operations had been segregated under separate captions on the Consolidated Balance Sheet as of December 31, 2001 as "Assets Pending Sale" and "Liabilities Related to Assets Pending Sale."

Upon completion of its merger with GPU, FirstEnergy accepted an October 2001 offer from Aquila, Inc. (formerly UtiliCorp United) to purchase Avon, FirstEnergy's wholly owned holding company for Midlands Electricity plc, for $2.1 billion (including the assumption of $1.7 billion of debt). The transaction closed on May 8, 2002 and reflected the March 2002 modification of

Aquila's initial offer such that Aquila acquired a 79.9 percent equity interest in Avon for approximately $1.9 billion (including the assumption of $1.7 billion of debt). Proceeds to FirstEnergy included $155 million in cash and a note receivable for approximately $87 million (representing the present value of $19 million per year to be received over six years beginning in 2003) from Aquila for its 79.9 percent interest. FirstEnergy and Aquila together own all of the outstanding shares of Avon through a jointly owned subsidiary, with each company having an ownership voting interest. Originally, in accordance with applicable accounting guidance, the earnings of those foreign operations were not recognized in current earnings from the date of the GPU acquisition. However, as a result of the decision to retain an ownership interest in Avon in the quarter ended March 31, 2002, EITF Issue No. 90-6, "Accounting for Certain Events Not Addressed in Issue No. 87-11 relating to an Acquired Operating Unit to be Sold" required FirstEnergy to reallocate the purchase price of GPU based on amounts as of the purchase date as if Avon had never been held for sale, including reversal of the effects of having applied EITF Issue No. 87-11, to the transaction. The effect of reallocating the

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purchase price and reversal of the effects of EITF Issue No. 87-11, including the allocation of capitalized interest, has been reflected in the Consolidated Statement of Income for the quarter ended March 31, 2002 by reclassifying certain revenue and expense amounts related to activity during the quarter ended March 31, 2002 to their respective income statement classifications. See Note 1 for the effects of the change in classification. In the fourth quarter of 2002, FirstEnergy recorded a $50 million charge to reduce the carrying value of its remaining 20.1 percent interest.

GPU's former Argentina operations were also identified by FirstEnergy for divestiture within one year of the merger. FirstEnergy determined the fair value of Emdersa, based on the best available information as of the date of the merger. Subsequent to that date, a number of economic events have occurred in Argentina which may have an impact on FirstEnergy's ability to realize Emdersa's estimated fair value. These events included currency devaluation, restrictions on repatriation of cash, and the anticipation of future asset sales in that region by competitors. FirstEnergy did not reach a definitive agreement to sell Emdersa as of December 31, 2002. Therefore, these assets were no longer classified as "Assets Pending Sale" on the Consolidated Balance Sheet as of December 31, 2002. Additionally, under EITF Issue No. 90-6, FirstEnergy recorded in the fourth quarter of 2002 a one-time, non-cash charge included as a "Cumulative Adjustment for Retained Businesses Previously Held for Sale" on its 2002 Consolidated Statement of Income related to Emdersa's cumulative results of operations from November 7, 2001 through September 30, 2002. The amount of this one-time, after-tax charge was $93.7 million, or $0.32 per share of common stock (comprised of $108.9 million in currency transaction losses arising principally from U.S. dollar denominated debt, offset by $15.2 million of operating income).

In October 2002, FirstEnergy began consolidating the results of Emdersa's operations in its financial statements. In addition to the currency transaction losses of $108.9 million, FirstEnergy also recognized a currency translation adjustment (CTA) in other comprehensive income (OCI) of $91.5 million as of December 31, 2002, which reduced FirstEnergy's common stockholders' equity. This adjustment represents the impact of translating Emdersa's financial statements from its functional currency to the U.S. dollar for GAAP financial reporting.

On April 18, 2003, FirstEnergy divested its ownership in Emdersa. The abandonment was accomplished by relinquishing FirstEnergy's shares of Emdersa's parent company, GPU Argentina Holdings, to that company's independent

Board of Directors, relieving FirstEnergy of all rights and obligations relative to this business. As a result of this action, FirstEnergy's gains and losses related to discontinuing these operations have been presented as a separate item on the Consolidated Statements of Income - "Discontinued operations" - in accordance with SFAS 144, "Accounting for the Impairment or Disposal of Long-Lived Assets." Due to the abandonment, FirstEnergy recognized a one-time, non-cash charge of $67.4 million in the second quarter of 2003. This charge resulted from realizing $89.8 million of currency translation losses through current period earnings, partially offset by a $22.4 million gain recognized from eliminating FirstEnergy's investment in Emdersa. Discontinued operations for the six-month period reflected a net after-tax charge of $60.5 million, which included $6.9 million of earnings from Emdersa in the first quarter of 2003. As a result of the abandonment, FirstEnergy has substantially divested all of GPU Capital's international operations.

The $67.4 million charge does not include the anticipated income tax benefits related to the abandonment. These tax benefits will be fully reserved during the second quarter. FirstEnergy anticipates tax benefits of approximately $129 million, of which $50 million would increase net income in the period that it becomes probable those benefits will be realized. The remaining $79 million of tax benefits would reduce goodwill recognized in connection with the acquisition of GPU.

SALE OF GENERATING ASSETS-

In November 2001, FirstEnergy reached an agreement to sell four coal-fired power plants totaling 2,535 megawatts (MW) to NRG Energy Inc. On August 8, 2002, FirstEnergy notified NRG that it was canceling the agreement because NRG stated that it could not complete the transaction under the original terms of the agreement. FirstEnergy also notified NRG that FirstEnergy reserves the right to pursue legal action against NRG, its affiliate and its parent, Xcel Energy for damages, based on the anticipatory breach of the agreement. On February 25, 2003, the U.S. Bankruptcy Court in Minnesota approved FirstEnergy's request for arbitration against NRG.

In December 2002, FirstEnergy decided to retain ownership of these plants after reviewing other bids it subsequently received from other parties who had expressed interest in purchasing the plants. Since FirstEnergy did not execute a sales agreement by year-end, it reflected approximately $74 million ($43 million net of tax) of previously unrecognized depreciation and other transaction costs in the fourth quarter of 2002 related to these plants from November 2001 through December 2002 on its Consolidated Statement of Income.

4 - REGULATORY MATTERS:

In Ohio, New Jersey and Pennsylvania, laws applicable to electric industry deregulation included similar provisions which are reflected in the Companies' respective state regulatory plans:

- allowing the Companies' electric customers to select their generation suppliers;

- establishing provider of last resort (PLR) obligations to customers in the Companies' service areas;

- allowing recovery of potentially stranded investment (sometimes referred to as transition costs);

- itemizing (unbundling) the current price of electricity into its component elements - including generation, transmission,

distribution and stranded costs recovery charges;

- deregulating the Companies' electric generation businesses; and

- continuing regulation of the Companies' transmission and distribution systems.

Ohio

In July 1999, Ohio's electric utility restructuring legislation, which allowed Ohio electric customers to select their generation suppliers beginning January 1, 2001, was signed into law. Among other things, the legislation provided for a 5% reduction on the generation portion of residential customers' bills and the opportunity to recover transition costs, including regulatory assets, from January 1, 2001 through December 31, 2005 (market development period). The period for the recovery of regulatory assets only can be extended up to December 31, 2010. The PUCO was authorized to determine the level of transition cost recovery, as well as the recovery period for the regulatory assets portion of those costs, in considering each Ohio electric utility's transition plan application.

In July 2000, the PUCO approved FirstEnergy's transition plan for OE, CEI and TE (Ohio Companies) as modified by a settlement agreement with major parties to the transition plan. The application of Statement of Financial Accounting Standards (SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulation" to OE's generation business and the nonnuclear generation businesses of CEI and TE was discontinued with the issuance of the PUCO transition plan order, as described further below. Major provisions of the settlement agreement consisted of approval of recovery of generation-related transition costs as filed of $4.0 billion net of deferred income taxes (OE-$1.6 billion, CEI-$1.6 billion and TE-$0.8 billion) and transition costs related to regulatory assets as filed of $2.9 billion net of deferred income taxes (OE-$1.0 billion, CEI-$1.4 billion and TE-$0.5 billion), with recovery through no later than 2006 for OE, mid-2007 for TE and 2008 for CEI, except where a longer period of recovery is provided for in the settlement agreement. The generation-related transition costs include $1.4 billion, net of deferred income taxes, (OE-$1.0 billion, CEI-$0.2 billion and TE-$0.2 billion) of impaired generating assets recognized as regulatory assets as described further below, $2.4 billion, net of deferred income taxes, (OE-$1.2 billion, CEI-$0.4 billion and TE-$0.8 billion) of above market operating lease costs (see note 1) and $0.8 billion, net of deferred income taxes, (CEI-$0.5 billion and TE-$0.3 billion) of additional plant costs that were reflected on CEI's and TE's regulatory financial statements.

Also as part of the settlement agreement, FirstEnergy is giving preferred access over its subsidiaries to nonaffiliated marketers, brokers and aggregators to 1,120 MW of generation capacity through 2005 at established prices for sales to the Ohio Companies' retail customers. Customer prices are frozen through the five-year market development period, which runs through the end of 2005, except for certain limited statutory exceptions, including the 5% reduction referred to above. In February 2003, the Ohio Companies were authorized increases in annual revenues aggregating approximately $50 million (OE-$41 million, CEI-$4 million and TE-$5 million) to recover their higher tax costs resulting from the Ohio deregulation legislation.

FirstEnergy's Ohio customers choosing alternative suppliers receive an additional incentive applied to the shopping credit (generation component) of 45% for residential customers, 30% for commercial customers and 15% for industrial customers. The amount of the incentive is deferred for future recovery from customers - recovery will be accomplished by extending the respective transition cost recovery period. If the customer shopping goals

established in the agreement had not been achieved by the end of 2005, the transition cost recovery periods could have been shortened for OE, CEI and TE to reduce recovery by as much as $500 million (OE - $250 million, CEI - $170 million and TE - $80 million). The Ohio Companies achieved all of their required 20% customer shopping goals in 2002. Accordingly, FirstEnergy believes that there will be no regulatory action reducing the recoverable transition costs.

New Jersey

JCP&L's 2001 Final Decision and Order (Final Order) with respect to its rate unbundling, stranded cost and restructuring filings confirmed rate reductions set forth in its 1999 Summary Order, which remain in effect at increasing levels through July 2003. The Final Order also confirmed the establishment of a non-bypassable societal benefits charge (SBC) to recover costs which include nuclear plant decommissioning and manufactured gas plant remediation, as well as a non-bypassable market transition charge (MTC) primarily to recover stranded costs. The NJBPU has deferred making a final determination of the net proceeds and stranded costs related to prior generating asset divestitures until JCP&L's request for an Internal Revenue Service (IRS) ruling regarding the treatment of associated federal income tax benefits is

acted upon. Should the IRS ruling support the return of the tax benefits to customers, there would be no effect to FirstEnergy's or JCP&L's net income since the contingency existed prior to the merger.

In addition, the Final Order provided for the ability to securitize stranded costs associated with the divested Oyster Creek Nuclear Generating Station. In 2002, JCP&L received NJBPU authorization to issue $320 million of transition bonds to securitize the recovery of these costs and which provided for a usage-based non-bypassable transition bond charge and for the transfer of the bondable transition property to another entity. JCP&L sold the transition bonds through its wholly owned subsidiary, JCP&L Transition Funding LLC, in June 2002 - those bonds are recognized on the Consolidated Balance Sheet.

JCP&L's PLR obligation to provide basic generation service (BGS) to non-shopping customers is supplied almost entirely from contracted and open market purchases. 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 nonutility generation (NUG) agreements exceed amounts collected through BGS and MTC rates. As of March 31, 2003, the accumulated deferred cost balance totaled approximately $530 million. The NJBPU also allowed securitization of JCP&L's deferred balance to the extent permitted by law upon application by JCP&L and a determination by the NJBPU that the conditions of the New Jersey restructuring legislation are met. There can be no assurance as to the extent, if any, that the NJBPU will permit such securitization.

Under New Jersey transition legislation, all electric distribution companies were required to file rate cases to determine the level of unbundled rate components to become effective August 1, 2003. JCP&L submitted two rate filings with the NJBPU in August 2002. The first filing requested increases in base electric rates of approximately $98 million annually. The second filing was a request to recover deferred costs that exceeded amounts being recovered under the current MTC and SBC rates; one proposed method of recovery of these costs is the securitization of the deferred balance. This securitization methodology is similar to the Oyster Creek securitization discussed above. Hearings began in February 2003. On March 18, 2003, a report prepared by independent auditors addressing costs deferred by JCP&L from August 1, 1999 through July 31, 2002, was transmitted to the Office of Administrative Law, where JCP&L's rate case is

being heard. While the auditors concluded that JCP&L's energy procurement strategy and process was reasonable and prudent, they identified potential disallowances approximating $17 million. The report subjected $436 million of deferred costs to a retrospective prudence review during a period of extreme price uncertainty and volatility in the energy markets. Although JCP&L disagrees with the potential disallowances, it is pleased with the report's major conclusions and overall tone. Hearings concluded on April 28, 2003, and initial briefs were filed on May 7, 2003. The JCP&L brief supports its two rate filings requesting an aggregate rate increase of approximately $122 million in base electric rates and the recovery of deferred costs based on the securitization methodology discussed above. If the securitization methodology is not allowed, then JCP&L has requested deferred cost recovery over a four-year period with a return on the unamortized deferred cost balance. This alternative would increase the overall rate request to approximately $246 million. JCP&L strongly disagrees with many of the positions taken by NJBPU Staff. The Staff's position would result in a $119 million estimated annual earnings decrease related to the electricity delivery charge. In addition, the Staff recommended disallowing approximately $153 million of deferred energy costs which would result in a one-time pre-tax charge against earnings of $153 million (or $0.31 per share of common stock). JCP&L will respond to the Staff's position in its Reply Brief which is due on May 21, 2003. The Administrative Law Judge's recommended decision is due by the end of June 2003 and the NJBPU's subsequent decision is due in July 2003.

In 1997, the NJBPU authorized JCP&L to recover from customers, subject to possible refund, $135 million of costs incurred in connection with a 1996 buyout of a power purchase agreement. JCP&L has recovered the full $135 million; the NJBPU has established a procedural schedule to take further evidence with respect to the buyout to enable it to make a final prudence determination contemporaneously with the resolution of the pending rate case.

In December 2001, the NJBPU authorized the auctioning of BGS for the period from August 1, 2002 through July 31, 2003 to meet the electricity demands of all customers who have not selected an alternative supplier. The auction results were approved by the NJBPU in February 2002, removing JCP&L's BGS obligation of 5,100 MW for the period August 1, 2002 through July 31, 2003. In February 2003, the NJBPU approved the BGS auction results for the period beginning August 1, 2003. The auction covered a fixed price bid (applicable to all residential and smaller commercial and industrial customers) and an hourly price bid (applicable to all large industrial customers) process. JCP&L sells all self-supplied energy (NUGs and owned generation) to the wholesale market with offsetting credits to its deferred energy balances.

Pennsylvania

The PPUC authorized 1998 rate restructuring plans for Penn, Met-Ed and Penelec. In 2000, the PPUC disallowed a portion of the requested additional stranded costs above those amounts granted in Met-Ed's and Penelec's 1998 rate restructuring plan orders. The PPUC required Met-Ed and Penelec to seek an IRS ruling regarding the return of certain unamortized investment tax credits and excess deferred income tax benefits to customers. Similar to JCP&L's

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situation, if the IRS ruling ultimately supports returning these tax benefits to customers, there would be no effect to FirstEnergy's, Met-Ed's or Penelec's net income since the contingency existed prior to the merger.

As a result of their generating asset divestitures, Met-Ed and Penelec obtained their supply of electricity to meet their PLR obligations almost entirely from contracted and open market purchases. In 2000, Met-Ed and

Penelec filed a petition with the PPUC seeking permission to defer, for future recovery, energy costs in excess of amounts reflected in their capped generation rates; the PPUC subsequently consolidated this petition in January 2001 with the FirstEnergy/GPU merger proceeding.

In June 2001, the PPUC entered orders approving the Settlement Stipulation with all of the major parties in the combined merger and rate relief proceedings which approved the merger and provided Met-Ed and Penelec PLR deferred accounting treatment for energy costs. The PPUC permitted Met-Ed and Penelec to defer for future recovery the difference between their actual energy costs and those reflected in their capped generation rates, retroactive to January 1, 2001. Correspondingly, in the event that energy costs incurred by Met-Ed and Penelec would be below their respective capped generation rates, that difference would have reduced costs that had been deferred for recovery in future periods. This PLR deferral accounting procedure was denied in a court decision discussed below. Met-Ed's and Penelec's PLR obligations extend through December 31, 2010; during that period competitive transition charge (CTC) revenues would have been applied to their stranded costs. Met-Ed and Penelec would have been permitted to recover any remaining stranded costs through a continuation of the CTC after December 31, 2010 through no later than December 31, 2015. Any amounts not expected to be recovered by December 31, 2015 would have been written off at the time such nonrecovery became probable.

Several parties had filed Petitions for Review in June and July 2001 with the Commonwealth Court of Pennsylvania regarding the June 2001 PPUC orders. On February 21, 2002, the Court affirmed the PPUC decision regarding the FirstEnergy/GPU merger, remanding the decision to the PPUC only with respect to the issue of merger savings. The Court reversed the PPUC's decision regarding the PLR obligations of Met-Ed and Penelec, and rejected those parts of the settlement that permitted the companies to defer for accounting purposes the difference between their wholesale power costs and the amount that they collect from retail customers. FirstEnergy and the PPUC each filed a Petition for Allowance of Appeal with the Pennsylvania Supreme Court on March 25, 2002, asking it to review the Commonwealth Court decision. Also on March 25, 2002, Citizens Power filed a motion seeking an appeal of the Commonwealth Court's decision to affirm the FirstEnergy and GPU merger with the Pennsylvania Supreme Court. In September 2002, FirstEnergy established reserves for Met-Ed's and Penelec's PLR deferred energy costs which aggregated $287.1 million. The reserves reflected the potential adverse impact of a pending Pennsylvania Supreme Court decision whether to review the Commonwealth Court ruling. FirstEnergy recorded an aggregate non-cash charge to income of $55.8 million ($32.6 million net of tax), or $0.11 per share of common stock, for the deferred costs incurred subsequent to the merger. The reserve for the remaining $231.3 million of deferred costs increased goodwill by an aggregate net of tax amount of $135.3 million.

On January 17, 2003, the Pennsylvania Supreme Court denied further appeals of the February 21, 2002 Pennsylvania Commonwealth Court decision, which effectively affirmed the PPUC's order approving the merger between FirstEnergy and GPU, let stand the Commonwealth Court's denial of PLR rate relief for Met-Ed and Penelec and remanded the merger savings issue back to the PPUC. On April 2, 2003, the PPUC remanded the merger savings issue to the Office of Administrative Law for hearings and directed Met-Ed and Penelec to file a position paper on the effect of the Commonwealth Court's order on the Settlement Stipulation by May 2, 2003. Because FirstEnergy had already reserved for the deferred energy costs and FES has largely hedged the anticipated PLR energy supply requirements for Met-Ed and Penelec through 2005 as discussed further below, FirstEnergy, Met-Ed and Penelec believe that the disallowance of continued CTC recovery of PLR costs will not have a future adverse financial impact during that period.

Effective September 1, 2002, Met-Ed and Penelec assigned their PLR responsibility to their FES affiliate through a wholesale power sale agreement.

The PLR sale currently runs through December 2003 and will be 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 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 under their NUG contracts and other existing 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 or below the shopping credit for their uncommitted PLR energy costs during the term of the agreement with FES. FES has hedged most of Met-Ed's and Penelec's unfilled PLR on-peak obligation through 2004 and a portion of 2005, the period during which deferred accounting was previously allowed under the PPUC's order. Met-Ed and Penelec are authorized to continue deferring differences between NUG contract costs and amounts recovered through their capped generation rates.

5 - NEW ACCOUNTING STANDARDS:

In June 2001, the Financial Accounting Standards Board (FASB) issued SFAS 143, "Accounting for Asset Retirement Obligations." The new statement provides accounting standards for retirement obligations associated with

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tangible long-lived assets, with adoption required by January 1, 2003. SFAS 143 requires that the fair value of a liability for an asset retirement obligation (ARO) be recorded 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, if the criteria for such treatment are met. Upon retirement, a gain or loss would be recorded if the cost to settle the retirement obligation differs from the carrying amount.

FirstEnergy identified applicable legal obligations as defined under the new standard for nuclear power plant decommissioning, reclamation of a sludge disposal pond related to the Bruce Mansfield plant, and closure of two coal ash disposal sites. As a result of adopting SFAS 143 in January 2003 asset retirement costs were recorded in the amount of $602 million as part of the carrying amount of the related long-lived asset, offset by accumulated depreciation of $415 million. The ARO liability at the date of adoption was $1.109 billion, including accumulated accretion for the period from the date the liability was incurred to the date of adoption. At December 31, 2002, FirstEnergy had recorded decommissioning liabilities of $1.243 billion. FirstEnergy expects substantially all nuclear decommissioning costs for Met-Ed, Penelec, JCP&L and Penn would be recoverable in rates over time. Therefore, FirstEnergy recognized a regulatory liability of $185 million upon adoption of SFAS 143 for the transition amounts related to establishing the ARO for nuclear decommissioning for these operating companies. The remaining 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 $174.7 million increase to income, or a $102.1 million increase net of tax, or $0.35 per share of common stock (basic and diluted).

FirstEnergy recorded an ARO for nuclear decommissioning ($1.096 billion) of the Beaver Valley 1, Beaver Valley 2, Davis-Besse, Perry, and TMI-2 nuclear generation facilities with the remaining ARO related to Bruce Mansfield's sludge impoundment facilities and two coal ash disposal sites. The Company maintains nuclear decommissioning trust funds, which had balances at March 31, 2003 of $1.061 billion. This number represents the fair value of the

assets that are legally restricted for purposes of settling the nuclear decommissioning ARO. The following table provides the beginning and ending aggregate carrying amount of the ARO and the changes to the balance for the period of January 1, 2003 through March 31, 2003.

ARO RECONCILIATION

(MILLIONS)

Beginning balance as of January 1, 2003	$1,109
Liabilities incurred in the current period	--
Liabilities settled in the current period	--
Accretion expense	18
Revisions in estimated cash flows	--
ENDING BALANCE AS OF MARCH 31, 2003	$1,127

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

ADJUSTED ARO RECONCILIATION

(MILLIONS)

Beginning balance as of January 1, 2002	$1,042
Accretion 2002	67
ENDING BALANCE AS OF DECEMBER 31, 2002	$1,109

In accordance with SFAS 143 FirstEnergy ceased the accounting practice of depreciating non-regulated generation assets using a cost of removal component in the depreciation rates that are applied to the generation assets. This practice recognizes accumulated depreciation in excess of the historical cost of an asset, because the removal cost exceeds the estimated salvage value. The change in accounting resulted in a $60 million credit to income as part of the SFAS 143 cumulative effect adjustment. Beginning in 2003 depreciation rates applied to non-regulated generation assets will exclude the cost of removal component and cost of removal will be charged to income rather than charged to the accumulated provision for depreciation. In accordance with SFAS 71, the regulated plant assets will continue the accounting practice of depreciating assets using a cost of removal component in the depreciation rates. The net removal cost credit balance included in the accumulated provision for regulated assets at March 31, 2003 is $296.1 million.

The following table provides on an adjusted basis the effect on income, as if the accounting for SFAS 143 had been applied in the first quarter 2002.

EFFECT OF THE CHANGE IN ACCOUNTING PRINCIPLE
APPLIED RETROACTIVELY TO THE FIRST QUARTER OF 2002

INCREASE(DECREASE)

	(MILLIONS) RESTATED (SEE NOTE 1)
Reported net income	$ 118
Replacement of decommissioning expense	26
Depreciation of asset retirement cost	(2)
Accretion of asset retirement cost	(10)
Income tax effect	(6)
Total earnings effect	8
Net income adjusted	$ 126
Earnings per share of common stock (basic and diluted):	
Net income as previously reported	$0.40
Adjustment for effect of change in accounting principle applied retroactively	0.02
Net income adjusted	$0.42

In January 2003, the FASB issued an interpretation of ARB No. 51, "Consolidated Financial Statements". The new interpretation provides guidance on consolidation of variable interest entities (VIEs), generally defined as certain entities in which equity investors do not have the characteristics of a controlling financial interest or do not have sufficient equity at risk for the entity to finance its activities without additional subordinated financial support from other parties. This interpretation requires an enterprise to disclose the nature of its involvement with a VIE if the enterprise has a significant variable interest in the VIE and to consolidate a VIE if the enterprise is the primary beneficiary. VIEs created after January 31, 2003 are immediately subject to the provisions of FIN 46. VIEs created before February 1, 2003 are subject to this interpretation's provisions in the first interim or annual reporting period after June 15, 2003 (FirstEnergy's third quarter of 2003). The FASB also identified transitional disclosure provisions for all financial statements issued after January 31, 2003.

FirstEnergy currently has transactions with entities in connection with sale and leaseback arrangements, the sale of preferred securities and debt secured by bondable property, which may fall within the scope of this interpretation and which are reasonably possible of meeting the definition of a VIE in accordance with FIN 46.

FirstEnergy currently consolidates the majority of these entities and believes it will continue to consolidate following the adoption of FIN 46. In addition to the entities FirstEnergy is currently consolidating FirstEnergy believes that the PNBV Capital Trust, which reacquired a portion of the off-balance sheet debt issued in connection with the sale and leaseback of OE's interest in the Perry Nuclear Plant and Beaver Valley Unit 2, would require consolidation. Ownership of the trust includes a three-percent equity interest by a nonaffiliated party and a three-percent equity interest by OES Ventures, a wholly owned subsidiary of OE. Full consolidation of the trust under FIN 46 would change the characterization of the PNBV trust investment to a lease obligation bond investment. Also, consolidation of the outside minority interest would be required, which would increase assets and liabilities by $12.0 million.

Issued by the FASB in April 2003, SFAS 149 further clarifies and amends accounting and reporting for derivative instruments. The statement amends SFAS133 for decisions made by the Derivative Implementation Group, as well as issues raised in connection with other FASB projects and implementation issues. The statement is effective for contracts entered into or modified after June 30, 2003 except for implementation issues that have been effective for quarters which began prior to June 15, 2003, which continue to be applied based on their original effective dates. FirstEnergy is currently assessing the new standard and has not yet determined the impact on its financial statements.

In June 2002, the EITF reached a partial consensus on Issue No. 02-03, "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities." Based on the EITF's partial consensus position, for periods after July 15, 2002, mark-to-market revenues and expenses and their related kilowatt-hour (KWH) sales and purchases on energy trading contracts must be shown on a net basis in the Consolidated Statements of Income. Prior to its adoption for 2002 year end reporting, FirstEnergy had previously reported such contracts as gross revenues and purchased power costs. Comparative quarterly disclosures and the Consolidated Statements of Income for revenues and expenses have been reclassified for 2002 to conform with the revised presentation. In addition, the related KWH sales and purchases statistics described under Management's

Discussion and Analysis of Results of Operations and Financial Condition were reclassified. The following table displays the impact of changing to a net presentation for FirstEnergy's energy trading operations.

	THREE MONTHS ENDED MARCH 31, 2002	
2002 IMPACT OF RECORDING ENERGY TRADING NET	REVENUES	EXPENSES
	RESTATED	RESTATED
	(IN MILLIONS)	
Total before adjustment	$2,893	$2,402
Adjustment	(40)	(40)
Total as reported	$2,853	$2,362

6 - SEGMENT INFORMATION:

FirstEnergy operates under two reportable segments: regulated services and competitive services. The aggregate "Other" segments do not individually meet the criteria to be considered a reportable segment. "Other" consists of interest expense related to the 2001 merger acquisition debt; the corporate support services operating segment and the international businesses acquired in the 2001 merger. The international business assets reflected in the 2002 "Other" assets amount included assets in the United Kingdom identified for divestiture (see Note 3 - Divestitures) which were sold in the second quarter of 2002. As those assets were in the process of being sold, their performance was not being reviewed by a chief operating decision maker and in accordance with SFAS 131, "Disclosures about Segments of an Enterprise and Related Information," did not qualify as an operating segment. The remaining assets and revenues for the corporate support services and the remaining international businesses were below the quantifiable threshold for operating segments for separate disclosure as "reportable segments." FirstEnergy's primary segment is its regulated services segment, which includes eight electric utility operating companies in Ohio, Pennsylvania and New Jersey that provide electric transmission and distribution services. Its other material business segment consists of the subsidiaries that operate unregulated energy and energy-related businesses.

The regulated services segment designs, constructs, operates and maintains FirstEnergy's regulated transmission and distribution systems. It also provides generation services to regulated franchise customers who have not chosen an alternative, competitive generation supplier. The regulated services segment obtains a portion of its required generation through power supply agreements with the competitive services segment.

SEGMENT FINANCIAL INFORMATION

	REGULATED SERVICES(D)	COMPETITIVE SERVICES	OTHER(C)	REC ADJ
		(IN MILLIONS)		
THREE MONTHS ENDED:				
MARCH 31, 2003				
External revenues	$ 2,315	$ 866	$ 51	$
Internal revenues	264	560	124	
Total revenues	2,579	1,426	175	
Depreciation and amortization	307	7	11	
Net interest charges	125	11	105	
Income taxes	167	(43)	(30)	
Income before cumulative effect of accounting change	216	(56)	(51)	
Net income	317	(55)	(44)	
Total assets	29,649	2,449	1,421	
Property additions	118	79	27	
MARCH 31, 2002				
External revenues	$ 1,995	$ 638	$ 214	$
Internal revenues	355	410	117	
Total revenues	2,350	1,048	331	
Depreciation and amortization	292	7	12	
Net interest charges	161	10	122	
Income taxes	185	(41)	(27)	

Net income (loss)	188	(60)	(22)
Total assets	29,552	2,706	6,288
Property additions	144	37	14

Reconciling adjustments to segment operating results from internal management reporting to consolidated external financial reporting:

(a) Principally fuel marketing revenues which are reflected as reductions to expenses for internal management reporting purposes.

(b) Elimination of intersegment transactions.

(c) Amounts restated in 2002 - See Note 1.

(d) Amounts restated in 2002 and 2003 - see Note 1.

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7. SUBSEQUENT EVENTS

ENVIRONMENTAL MATTERS-

On August 8, 2003, FirstEnergy, OE and Penn reported a development regarding a complaint filed by the U.S. Department of Justice with respect to the W.H. Sammis Plant. As reported, on August 7, 2003, the United States District Court for the Southern District of Ohio ruled that 11 projects undertaken at the 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, which is currently scheduled to be ready for trial beginning March 15, 2004, will address civil penalties and what, if any, actions should be taken to further reduce emissions at the plant. In the ruling, the Court indicated 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." Management is unable to predict the ultimate outcome of this matter. The potential penalties that may be imposed, as well as the capital expenditures necessary to comply with substantive remedial measures that may be required, may have a material adverse impact on the Company's financial condition.

REGULATORY MATTERS-

New Jersey

On July 25, 2003, FirstEnergy and JCP&L announced that review is underway concerning a decision by the NJBPU on JCP&L's rate proceeding. Based on that review, JCP&L will decide its appropriate course of action, which could include filing a request for reconsideration with the NJBPU and possibly an appeal to the Appellate Division of the Superior Court of New Jersey.

In its ruling, the NJBPU reduced JCP&L's annual revenues by approximately $62 million, for an average rate decrease of 3 percent, effective August 1, 2003. The NJBPU decision also provided for an interim return on equity of 9.5 percent on JCP&L's rate base for the next 6 to 12 months. During that period, JCP&L would initiate another proceeding to request recovery of additional expenses incurred to enhance system reliability. In that proceeding,

the NJBPU could increase the return on equity to 9.75 percent or decrease it to 9.25 percent, depending on its assessment of the reliability of JCP&L's service. Any reduction could be retroactive to August 1, 2003.

The NJBPU decision reflects elimination of $111 million in annual customer credits mandated by the New Jersey Electric Discount and Energy Competition Act (EDECA); a $223 million reduction in the energy delivery charge; a net $1 million increase in the SBC; and a $49 million increase in the MTC. The $1 million net SBC increase reflects approximately a $22 million increase related to universal services' costs previously approved in a separate proceeding, as well as reductions in other components of the SBC.

The MTC would allow for the recovery of $465 million of deferred energy costs over the next 10 years on an interim basis, thus disallowing $153 million of the $618 million provided for in the settlement agreement. This decision reflects the NJBPU's belief that a hindsight review comparing JCP&L's power purchases to spot market prices provides the appropriate benchmark for recovery. JCP&L's deferred energy costs primarily reflect mandated purchase power contracts with NUG's that are above wholesale market prices, and costs of providing basic generation service to customers in excess of the company's capped basic generation service charges during the transition period under EDECA, which ends August 1, 2003. At that time, the generation portion of most customer bills will increase by an average of 7.5 percent as a result of the outcome of the basic generation service auction conducted earlier this year by the BPU.

In the second quarter of 2003, JCP&L recorded charges to net income aggregating $158 million ($94 million net of tax) consisting of the $153 million deferred energy costs and other regulatory assets.

On July 25, 2003, the NJBPU approved a Stipulation of Settlement between the parties and authorized the recovery of the total $135 million of the Freehold buyout costs, eliminating the interim nature of the recovery.

Pennsylvania

On April 2, 2003, the PPUC remanded the merger savings issue to the Office of Administrative Law for hearings and directed Met-Ed and Penelec to file a position paper on the effect of the Commonwealth Court's order on the Settlement Stipulation by May 2, 2003 and for the other parties to file their responses to the Met-Ed and Penelec position paper by June 2, 2003. In summary, the Met-Ed and Penelec position paper essentially stated the following:

- Because no stay of the PPUC's June 2001 order approving the Settlement Stipulation was issued or sought, the Stipulation remained in effect until the Pennsylvania Supreme Court denied all appeal applications in January 2003,
  - As of January 16, 2003, the Supreme Court's Order became final and the portions of the PPUC's June 2001 Order that were inconsistent with the Supreme Court's findings were reversed,
  - The Supreme Court's finding effectively amended the Stipulation to remove the PLR cost recovery and deferral provisions and reinstated the GENCO Code of Conduct as a merger condition, and
  - All other provisions included in the Stipulation unrelated to these three issues remain in effect.

The other parties' responses included significant disagreement with the position paper and disagreement among the other parties themselves, including the Stipulation's original signatory parties. Some parties believe that no portion of the Stipulation has survived the Commonwealth Court's Order. Because of these disagreements, Met-Ed and Penelec filed a letter on June 11, 2003 with the Administrative Law Judge assigned to the remanded case voiding the Stipulation in its entirety pursuant to the termination provisions. They believe this will significantly simplify the issues in the pending action by reinstating Met-Ed's and Penelec's Restructuring Settlement previously approved by the PPUC. In addition, they have agreed to voluntarily continue certain Stipulation provisions including funding for energy and demand side response programs and to cap distribution rates at current levels through 2007. This voluntary distribution rate cap is contingent upon a finding that Met-Ed and Penelec have satisfied the "public interest" test applicable to mergers and that any rate impacts of merger savings will be dealt with in a subsequent rate case. Based upon this letter, Met-Ed and Penelec believe that the remaining issues before the Administrative Law Judge are the appropriate treatment of merger savings issues and whether their accounting and related tariff modifications are consistent with the Court Order.

INTERNATIONAL OPERATIONS-

Pending Sale of Remaining Investment in Avon and Sale of Note from Aquila

On May 22, 2003, FirstEnergy announced it reached an agreement to sell its 20.1 percent interest in Avon to Scottish and Southern Energy plc; that agreement also includes Aquila's 79.9 percent interest (See Note 3). Under terms of the agreement, Scottish and Southern will pay FirstEnergy and Aquila an aggregate $70 million (FirstEnergy's share would be approximately $14 million). Avon's debt will remain with that company. FirstEnergy also recognized in the second quarter of 2003 an impairment of $12.6 million ($8.2 million after tax) related to the carrying value of the note receivable from the initial sale of a 79.9 percent interest in Avon that occurred in May 2002. After receiving the first annual installment payment of $19 million in May 2003, FirstEnergy sold the remaining balance of the note in the secondary market and received $63.2 million in proceeds on July 28, 2003.

RECENTLY ISSUED ACCOUNTING STANDARDS NOT YET IMPLEMENTED-

SFAS 150, "Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity"

In May 2003, the FASB issued SFAS 150, which establishes standards for how an issuer classifies and measures certain financial instruments with characteristics of both liabilities and equity. In accordance with the standard, certain financial instruments that embody obligations for the issuer are required to be classified as liabilities. SFAS 150 is effective for financial instruments entered into or modified after May 31, 2003 and is effective at the beginning of the first interim period beginning after June 15, 2003 (FirstEnergy's third quarter of 2003) for all other financial instruments.

FirstEnergy did not enter into or modify any financial instruments within the scope of SFAS 150 during June 2003. Upon adoption of SFAS 150, effective July 1, 2003, FirstEnergy expects to classify as debt the preferred stock of consolidated subsidiaries subject to mandatory redemptions with a carrying value of approximately $19 million as of June 30, 2003. Subsidiary preferred dividends on FirstEnergy's Consolidated Statements of Income are currently included in net interest charges. Therefore, the application of SFAS 150 will not require the reclassification of such preferred dividends to net interest charges.

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DIG Implementation Issue No. C20 for SFAS 133, "Scope Exceptions: Interpretation of the Meaning of Not Clearly and Closely Related in Paragraph 10(b) Regarding Contracts with a Price Adjustment Feature"

In June 2003, the FASB cleared DIG Issue C20 for implementation in fiscal quarters beginning after July 10, 2003 which would correspond to FirstEnergy's fourth quarter of 2003. The issue supersedes earlier DIG Issue C11, "Interpretation of Clearly and Closely Related in Contracts That Qualify for the Normal Purchases and Normal Sales Exception." DIG Issue C20 provides guidance regarding when the presence in a contract of a general index, such as the Consumer Price Index, would prevent that contract from qualifying for the normal purchases and normal sales (NPNS) exception under SFAS 133, as amended, and therefore exempt from the mark-to-market treatment of certain contracts. DIG Issue C20 is to be applied prospectively to all existing contracts as of its effective date and for all future transactions. If it is determined under DIG Issue C20 guidance that the NPNS exception was claimed for an existing contract that was not eligible for this exception, the contract will be recorded at fair value, with a corresponding adjustment of net income as the cumulative effect of a change in accounting principle in the fourth quarter of 2003. FirstEnergy is currently assessing the new guidance and has not yet determined the impact on its financial statements.

EITF Issue No. 01-08, "Determining whether an Arrangement Contains a Lease"

In May 2003, the EITF reached a consensus regarding when arrangements contain a lease. Based on the EITF consensus, an arrangement contains a lease if (1) it identifies specific property, plant or equipment (explicitly or implicitly), and (2) the arrangement transfers the right to the purchaser to control the use of the property, plant or equipment. The consensus will be applied prospectively to arrangements committed to, modified or acquired through a business combination, beginning in the third quarter of 2003. FirstEnergy is currently assessing the new EITF consensus and has not yet determined the impact on its financial position or results of operations following adoption.

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FIRSTENERGY CORP.

CONSOLIDATED STATEMENTS OF INCOME
(UNAUDITED)

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2003
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REVENUES:	
Electric utilities	$ 2,315
Unregulated businesses	918
Total revenues	3,233
EXPENSES:	
Fuel and purchased power	1,192
Purchased gas	229
Other operating expenses	899
Provision for depreciation and amortization	324
General taxes	178
Total expenses	2,824
INCOME BEFORE INTEREST AND INCOME TAXES	409
NET INTEREST CHARGES:	
Interest expense	200
Capitalized interest	(9
Subsidiaries' preferred stock dividends	14
Net interest charges	206
INCOME TAXES	93
INCOME BEFORE DISCONTINUED OPERATIONS AND CUMULATIVE EFFECT OF ACCOUNTING CHANGE	109
Discontinued operations	6
Cumulative effect of accounting change (net of income taxes of $72,516,000) (Note 5)	102
NET INCOME	$ 218
BASIC EARNINGS PER SHARE OF COMMON STOCK:	
Income before discontinued operations and cumulative effect of accounting change	$
Discontinued operations (net of income taxes)	
Cumulative effect of accounting change (net of income taxes) (Note 5)	
Net income	$
WEIGHTED AVERAGE NUMBER OF BASIC SHARES OUTSTANDING	293
DILUTED EARNINGS PER SHARE OF COMMON STOCK:	
Income before discontinued operations and cumulative effect of accounting change	$
Discontinued operations (net of taxes)	
Cumulative e	