CLEVELAND ELECTRIC ILLUMINATING CO
Form 10-Q
May 03, 2011

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D. C. 20549
FORM 10-Q

(Mark One)

þ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the quarterly period ended March 31, 2011
OR

o **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
000-53742	FIRSTENERGY SOLUTIONS CORP. (An Ohio Corporation) c/o FirstEnergy Corp. 76 South Main Street Akron, OH 44308 Telephone (800)736-3402	31-1560186
1-2578	OHIO EDISON COMPANY (An Ohio Corporation) c/o FirstEnergy Corp. 76 South Main Street Akron, OH 44308 Telephone (800)736-3402	34-0437786
1-2323	THE CLEVELAND ELECTRIC ILLUMINATING COMPANY (An Ohio Corporation) c/o FirstEnergy Corp. 76 South Main Street Akron, OH 44308 Telephone (800)736-3402	34-0150020
1-3583	THE TOLEDO EDISON COMPANY (An Ohio Corporation) c/o FirstEnergy Corp.	34-4375005

76 South Main Street
Akron, OH 44308
Telephone (800)736-3402

1-3141	**JERSEY CENTRAL POWER & LIGHT COMPANY** **(A New Jersey Corporation)** **c/o FirstEnergy Corp.** **76 South Main Street** **Akron, OH 44308** **Telephone (800)736-3402**	**21-0485010**
1-446	**METROPOLITAN EDISON COMPANY** **(A Pennsylvania Corporation)** **c/o FirstEnergy Corp.** **76 South Main Street** **Akron, OH 44308** **Telephone (800)736-3402**	**23-0870160**
1-3522	**PENNSYLVANIA ELECTRIC COMPANY** **(A Pennsylvania Corporation)** **c/o FirstEnergy Corp.** **76 South Main Street** **Akron, OH 44308** **Telephone (800)736-3402**	**25-0718085**

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes þ No o	FirstEnergy Corp., FirstEnergy Solutions Corp., Ohio Edison Company, The Cleveland Electric Illuminating Company, The Toledo Edison Company, Jersey Central Power & Light Company, Metropolitan Edison Company and Pennsylvania Electric Company

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

Yes þ No o	FirstEnergy Corp.
Yes o No o	FirstEnergy Solutions Corp., Ohio Edison Company, The Cleveland Electric Illuminating Company, The Toledo Edison Company, Jersey Central Power & Light Company, Metropolitan Edison Company, and Pennsylvania Electric Company

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of large accelerated filer, accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act.

Large Accelerated Filer þ	FirstEnergy Corp.
Accelerated Filer o	N/A

Non-accelerated Filer (Do not check if a smaller reporting company) þ	FirstEnergy Solutions Corp., Ohio Edison Company, The Cleveland Electric Illuminating Company, The Toledo Edison Company, Jersey Central Power & Light Company, Metropolitan Edison Company and Pennsylvania Electric Company
Smaller Reporting Company o	N/A

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act).

Yes o No þ	FirstEnergy Corp., FirstEnergy Solutions Corp., Ohio Edison Company, The Cleveland Electric Illuminating Company, The Toledo Edison Company, Jersey Central Power & Light Company, Metropolitan Edison Company and Pennsylvania Electric Company

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 April 29, 2011
FirstEnergy Corp., $.10 par value	418,216,437
FirstEnergy Solutions Corp., no par value	7
Ohio Edison Company, no par value	60
The Cleveland Electric Illuminating Company, no par value	67,930,743
The Toledo Edison Company, $5 par value	29,402,054
Jersey Central Power & Light Company, $10 par value	13,628,447
Metropolitan Edison Company, no par value	740,905
Pennsylvania Electric Company, $20 par value	4,427,577

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

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

FirstEnergy Web Site

Each of the registrants Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, and amendments to those reports filed with or furnished to the SEC pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 are also made available free of charge on or through FirstEnergy s Internet web site at www.firstenergycorp.com.

These reports are posted on the web site as soon as reasonably practicable after they are electronically filed with the SEC. Additionally, the registrants routinely post important information on FirstEnergy s Internet web site and recognize FirstEnergy s Internet web site as a channel of distribution to reach public investors and as a means of disclosing material non-public information for complying with disclosure obligations under SEC Regulation FD. Information contained on FirstEnergy s Internet web site shall not be deemed incorporated into, or to be part of, this report.

OMISSION OF CERTAIN INFORMATION

FirstEnergy Solutions Corp., Ohio Edison Company, The Cleveland Electric Illuminating Company, The Toledo Edison Company, Jersey Central Power & Light Company, Metropolitan Edison Company and Pennsylvania Electric Company meet the conditions set forth in General Instruction H(1)(a) and (b) of Form 10-Q and are therefore filing this Form 10-Q with the reduced disclosure format specified in General Instruction H(2) to Form 10-Q.

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Forward-Looking Statements: 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 include declarations regarding management s intents, beliefs and current expectations. These statements typically contain, but are not limited to, the terms anticipate, potential, expect, believe, estimate and similar words. Forward-lo statements involve estimates, assumptions, known and unknown risks, uncertainties and other factors that may cause actual results, performance or achievements to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements.

Actual results may differ materially due to:

- The speed and nature of increased competition in the electric utility industry.
- The impact of the regulatory process on the pending matters in the various states in which we do business including, but not limited to, matters related to rates.
- The status of the PATH project in light of PJM s direction to suspend work on the project pending review of its planning process, its re-evaluation of the need for the project and the uncertainty of the timing and amounts of any related capital expenditures.
- Business and regulatory impacts from ATSI s realignment into PJM Interconnection, L.L.C.
- Economic or weather conditions affecting future sales and margins.
- Changes in markets for energy services.
- Changing energy and commodity market prices and availability.
- Financial derivative reforms that could increase our liquidity needs and collateral costs.
- Replacement power costs being higher than anticipated or inadequately hedged.
- The continued ability of FirstEnergy s regulated utilities to collect transition and other costs.
- Operation and maintenance costs being higher than anticipated.
- Other legislative and regulatory changes, and revised environmental requirements, including possible GHG emission, water intake and coal combustion residual regulations, the potential impacts of any laws, rules or regulations that ultimately replace CAIR and the effects of the EPA s recently released MACT proposal to establish certain mercury and other emission standards for electric generating units.
- The uncertainty of the timing and amounts of the capital expenditures that may arise in connection with any NSR litigation or potential regulatory initiatives or rulemakings (including that such expenditures could result in our decision to shut down or idle certain generating units).
- Adverse regulatory or legal decisions and outcomes (including, but not limited to, the revocation of necessary licenses or operating permits) and oversight by the NRC, including as a result of the incident at Japan s Fukushima Daiichi Nuclear Plant.
- Adverse legal decisions and outcomes related to Met-Ed s and Penelec s transmission service charge appeal at the Commonwealth Court of Pennsylvania.
- The continuing availability of generating units and changes in their ability to operate at or near full capacity.
- The ability to comply with applicable state and federal reliability standards and energy efficiency mandates.
- Changes in customers demand for power, including but not limited to, changes resulting from the implementation of state and federal energy efficiency mandates.
- The ability to accomplish or realize anticipated benefits from strategic goals.
- Efforts and our ability to improve electric commodity margins and the impact of, among other factors, the increased cost of coal and coal transportation on such margins.
- The ability to experience growth in the distribution business.
- The changing market conditions that could affect the value of assets held in the registrants nuclear decommissioning trusts, pension trusts and other trust funds, and cause FirstEnergy to make additional contributions sooner, or in amounts that are larger than currently anticipated.

- The ability to access the public securities and other capital and credit markets in accordance with FirstEnergy s financing plan, the cost of such capital and overall condition of the capital and credit markets affecting the registrants and other FirstEnergy subsidiaries.
- Changes in general economic conditions affecting the registrants and other FirstEnergy subsidiaries.
- Interest rates and any actions taken by credit rating agencies that could negatively affect the registrants access to financing or their costs and increase requirements to post additional collateral to support outstanding commodity positions, LOCs and other financial guarantees.
- The continuing uncertainty of the national and regional economy and its impact on the registrants major industrial and commercial customers and those of other FirstEnergy subsidiaries.
- Issues concerning the soundness of financial institutions and counterparties with which the registrants and FirstEnergy s other subsidiaries do business.
- Issues arising from the recently completed merger of FirstEnergy and Allegheny Energy, Inc. and the ongoing coordination of their combined operations including FirstEnergy s ability to maintain relationships with customers, employees or suppliers, as well as the ability to successfully integrate the businesses and realize cost savings and any other synergies and the risk that the credit ratings of the combined company or its subsidiaries may be different from what the companies expect.
- The risks and other factors discussed from time to time in the registrants SEC filings, and other similar factors.

Dividends declared from time to time on FirstEnergy s common stock during any annual period may in aggregate vary from the indicated amount due to circumstances considered by FirstEnergy s Board of Directors at the time of the actual declarations. A security rating is not a recommendation to buy, or hold securities and is subject to revision or withdrawal at any time by the assigning rating agency. Each rating should be evaluated independently of any other rating.

The foregoing review of factors should not be construed as exhaustive. New factors emerge from time to time, and it is not possible for management to predict all such factors, nor assess the impact of any such factor on the registrants business or the extent to which any factor, or combination of factors, may cause results to differ materially from those contained in any forward-looking statements. The registrants expressly disclaim any current intention to update any forward-looking statements contained herein as a result of new information, future events or otherwise.

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GLOSSARY OF TERMS

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

AE	Allegheny Energy, Inc., a Maryland utility holding company that merged with a subsidiary of FirstEnergy on February 25, 2011
AESC	Allegheny Energy Service Corporation, a subsidiary of AE
AE Supply	Allegheny Energy Supply Company LLC, an unregulated generation subsidiary of AE
AGC	Allegheny Generating Company, a generation subsidiary of AE
Allegheny	Allegheny Energy, Inc., together with its consolidated subsidiaries
AVE	Allegheny Ventures, Inc.
ATSI	American Transmission Systems, Incorporated, which owns and operates transmission facilities
CEI	The Cleveland Electric Illuminating Company, an Ohio electric utility operating subsidiary
FENOC	FirstEnergy Nuclear Operating Company, which operates nuclear generating facilities
FES	FirstEnergy Solutions Corp., which provides energy-related products and services
FESC	FirstEnergy Service Company, which provides legal, financial and other corporate support services
FEV	FirstEnergy Ventures Corp., which invests in certain unregulated enterprises and business ventures
FGCO	FirstEnergy Generation Corp., which owns and operates non-nuclear generating facilities
FirstEnergy	FirstEnergy Corp., a public utility holding company
Global Rail	A joint venture between FEV and WMB Loan Ventures II LLC, that owns coal transportation operations near Roundup, Montana
GPU	GPU, Inc., former parent of JCP&L, Met-Ed and Penelec, that merged with FirstEnergy on November 7, 2001
JCP&L	Jersey Central Power & Light Company, a New Jersey electric utility operating subsidiary
Met-Ed	Metropolitan Edison Company, a Pennsylvania electric utility operating subsidiary
MP	Monongahela Power Company, a West Virginia electric utility operating subsidiary of AE
NGC	FirstEnergy Nuclear Generation Corp., owns nuclear generating facilities
OE	Ohio Edison Company, an Ohio electric utility operating subsidiary
Ohio Companies	CEI, OE and TE
PATH	Potomac-Appalachian Transmission Highline LLC, a joint venture between Allegheny and a subsidiary of American Electric Power Company, Inc.
PATH-VA	PATH Allegheny Virginia Transmission Corporation
PE	The Potomac Edison Company, a Maryland electric operating subsidiary of AE
Penelec	Pennsylvania Electric Company, a Pennsylvania electric utility operating subsidiary
Penn	Pennsylvania Power Company, a Pennsylvania electric utility operating subsidiary of OE
Pennsylvania Companies	Met-Ed, Penelec, Penn and WP
PNBV	PNBV Capital Trust, a special purpose entity created by OE in 1996
Shippingport	

	Shippingport Capital Trust, a special purpose entity created by CEI and TE in 1997
Signal Peak	A joint venture between FEV and WMB Loan Ventures LLC, that owns mining operations near Roundup, Montana
TE	The Toledo Edison Company, an Ohio electric utility operating subsidiary
TrAIL	Trans-Allegheny Interstate Line Company
Utilities	OE, CEI, TE, Penn, JCP&L, Met-Ed, Penelec, MP, PE and WP
Utility Registrants	OE, CEI, TE, JCP&L, Met-Ed and Penelec
WP	West Penn Power Company, a Pennsylvania electric utility operating subsidiary of AE

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

ALJ	Administrative Law Judge
AOCL	Accumulated Other Comprehensive Loss
AEP	American Electric Power
AQC	Air Quality Control
ARO	Asset Retirement Obligation
BGS	Basic Generation Service
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CATR	Clean Air Transport Rule
CBP	Competitive Bid Process
CDWR	California Department of Water Resources
CO_2	Carbon Dioxide
CTC	Competitive Transition Charge

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GLOSSARY OF TERMS, Cont d.

DCPD	Deferred Compensation Plan for Outside Directors
DOE	United States Department of Energy
DOJ	United States Department of Justice
DPA	Department of the Public Advocate, Division of Rate Counsel (New Jersey)
DSP	Default Service Plan
EDCP	Executive Deferred Compensation Plan
EE&C	Energy Efficiency and Conservation
EIS	Energy Insurance Services, Inc.
EMP	Energy Master Plan
ENEC	Expanded Net Energy Cost
EPA	United States Environmental Protection Agency
ESOP	Employee Stock Ownership Plan
ESP	Electric Security Plan
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FMB	First Mortgage Bond
FPA	Federal Power Act
FRR	Fixed Resource Requirement
FTRs	Financial Transmission Rights
GAAP	Generally Accepted Accounting Principles in the United States
RGGI	Regional Greenhouse Gas Initiative
GHG	Greenhouse Gases
IRS	Internal Revenue Service
JOA	Joint Operating Agreement
kV	Kilovolt
KWH	Kilowatt-hours
LED	Light-Emitting Diode
LOC	Letter of Credit
LTIP	Long-Term Incentive Plan
MACT	Maximum Achievable Control Technology
MDPSC	Maryland Public Service Commission
MEIUG	Met-Ed Industrial Users Group
MISO	Midwest Independent Transmission System Operator, Inc.
Moody s	Moody s Investors Service, Inc.
MRO	Market Rate Offer
MSHA	Mine Safety and Health Administration
MTEP	MISO Regional Transmission Expansion Plan
MW	Megawatts
MWH	Megawatt-hours
NAAQS	National Ambient Air Quality Standards
NDT	Nuclear Decommissioning Trusts
NERC	North American Electric Reliability Corporation
NJBPU	New Jersey Board of Public Utilities
NNSR	Non-Attainment New Source Review
NOAC	Northwest Ohio Aggregation Coalition
NOPEC	Northeast Ohio Public Energy Council
NOV	Notice of Violation

NO_X	Nitrogen Oxide
NRC	Nuclear Regulatory Commission
NSR	New Source Review
NUG	Non-Utility Generation
NUGC	Non-Utility Generation Charge
NYSEG	New York State Electric and Gas
OCC	Ohio Consumers Counsel
OCI	Other Comprehensive Income
OPEB	Other Post-Employment Benefits
OVEC	Ohio Valley Electric Corporation
PADEP	Pennsylvania Department of Environmental Protection
PCRB	Pollution Control Revenue Bond
PICA	Pennsylvania Intergovernmental Cooperation Authority
PJM	PJM Interconnection L. L. C.
POLR	Provider of Last Resort; an electric utility s obligation to provide generation service to customers Whose alternative supplier fails to deliver service
PPUC	Pennsylvania Public Utility Commission

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GLOSSARY OF TERMS, Cont d.

PSCWV	Public Service Commission of West Virginia
PSA	Power Supply Agreement
PSD	Prevention of Significant Deterioration
PUCO	Public Utilities Commission of Ohio
PURPA	Public Utility Regulatory Policies Act of 1978
RECs	Renewable Energy Credits
RFP	Request for Proposal
RGGI	Regional Greenhouse Gas Initiative
RTEP	Regional Transmission Expansion Plan
RTC	Regulatory Transition Charge
RTO	Regional Transmission Organization
S&P	Standard & Poor s Ratings Service
SB221	Amended Substitute Senate Bill 221
SBC	Societal Benefits Charge
SEC	U.S. Securities and Exchange Commission
SIP	State Implementation Plan(s) Under the Clean Air Act
SMIP	Smart Meter Implementation Plan
SNCR	Selective Non-Catalytic Reduction
SO_2	Sulfur Dioxide
SOS	Standard Offer Service
TBC	Transition Bond Charge
TDS	Total Dissolved Solid
TMDL	Total Maximum Daily Load
TMI-2	Three Mile Island Unit 2
TSC	Transmission Service Charge
VIE	Variable Interest Entity
VSCC	Virginia State Corporation Commission
WVDEP	West Virginia Department of Environmental Protection
WVPSC	Public Service Commission of West Virginia

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FIRSTENERGY CORP.
CONSOLIDATED STATEMENTS OF INCOME
(Unaudited)

In millions, except per share amounts	Three Months Ended March 31 2011	2010
REVENUES:		
Electric utilities	$ 2,332	$ 2,543
Unregulated businesses	1,244	756
Total revenues*	3,576	3,299
EXPENSES:		
Fuel	453	334
Purchased power	1,186	1,238
Other operating expenses	1,033	701
Provision for depreciation	220	193
Amortization of regulatory assets	132	212
General taxes	237	205
Total expenses	3,261	2,883
OPERATING INCOME	315	416
OTHER INCOME (EXPENSE):		
Investment income	21	16
Interest expense	(231)	(213)
Capitalized interest	18	41
Total other expense	(192)	(156)
INCOME BEFORE INCOME TAXES	123	260
INCOME TAXES	78	111
NET INCOME	45	149
Loss attributable to noncontrolling interest	(5)	(6)
EARNINGS AVAILABLE TO FIRSTENERGY CORP.	$ 50	$ 155

BASIC EARNINGS PER SHARE OF COMMON STOCK	$	0.15	$	0.51
WEIGHTED AVERAGE NUMBER OF BASIC SHARES OUTSTANDING		342		304
DILUTED EARNINGS PER SHARE OF COMMON STOCK	$	0.15	$	0.51
WEIGHTED AVERAGE NUMBER OF DILUTED SHARES OUTSTANDING		343		306
DIVIDENDS DECLARED PER SHARE OF COMMON STOCK	$	0.55	$	0.55

* Includes $119 and $109 million of excise tax collections in the three months ended March 31, 2011 and 2010, respectively.

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

FIRSTENERGY CORP.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(Unaudited)

	Three Months Ended March 31	
(In millions)	**2011**	**2010**
NET INCOME	$ 45	$ 149
OTHER COMPREHENSIVE INCOME:		
Pension and other postretirement benefits	19	13
Unrealized gain (loss) on derivative hedges	(6)	4
Change in unrealized gain on available-for-sale securities	9	6
Other comprehensive income	22	23
Income tax expense related to other comprehensive income	1	7
Other comprehensive income, net of tax	21	16
COMPREHENSIVE INCOME	66	165
COMPREHENSIVE LOSS ATTRIBUTABLE TO NONCONTROLLING INTEREST	(5)	(6)
COMPREHENSIVE INCOME AVAILABLE TO FIRSTENERGY CORP.	$ 71	$ 171

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

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FIRSTENERGY CORP.
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions)	March 31, 2011	December 31, 2010
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 1,101	$ 1,019
Receivables-		
Customers, net of allowance for uncollectible accounts of $38 in 2011 and $36 in 2010	1,636	1,392
Other, net of allowance for uncollectible accounts of $10 in 2011 and $8 in 2010	229	176
Materials and supplies	852	638
Prepaid taxes	241	199
Derivatives	377	182
Other	210	92
	4,646	3,698
PROPERTY, PLANT AND EQUIPMENT:		
In service	38,168	29,451
Less Accumulated provision for depreciation	11,345	11,180
	26,823	18,271
Construction work in progress	2,322	1,517
Property, plant and equipment held for sale, net	490	
	29,635	19,788
INVESTMENTS:		
Nuclear plant decommissioning trusts	2,018	1,973
Investments in lease obligation bonds	422	476
Nuclear fuel disposal trust	207	208
Other	434	345
	3,081	3,002
DEFERRED CHARGES AND OTHER ASSETS:		
Goodwill	6,527	5,575
Regulatory assets	2,084	1,826
Intangible assets	1,075	256
Other	818	660
	10,504	8,317
	$ 47,866	$ 34,805

LIABILITIES AND CAPITALIZATION

CURRENT LIABILITIES:		
Currently payable long-term debt	$ 1,385	$ 1,486
Short-term borrowings	486	700
Accounts payable	1,080	872
Accrued taxes	412	326
Accrued compensation and benefits	312	315
Derivatives	425	266
Other	1,062	733
	5,162	4,698
CAPITALIZATION:		
Common stockholders equity-		
Common stock, $0.10 par value, authorized 490,000,000 shares- 418,216,437 shares outstanding	42	31
Other paid-in capital	9,779	5,444
Accumulated other comprehensive loss	(1,518)	(1,539)
Retained earnings	4,426	4,609
Total common stockholders equity	12,729	8,545
Noncontrolling interest	(40)	(32)
Total equity	12,689	8,513
Long-term debt and other long-term obligations	17,535	12,579
	30,224	21,092
NONCURRENT LIABILITIES:		
Accumulated deferred income taxes	4,832	2,879
Retirement benefits	2,313	1,868
Asset retirement obligations	1,443	1,407
Deferred gain on sale and leaseback transaction	951	959
Power purchase contract liability	606	466
Other	2,335	1,436
	12,480	9,015
COMMITMENTS, GUARANTEES AND CONTINGENCIES (Note 9)		
	$ 47,866	$ 34,805

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

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FIRSTENERGY CORP.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

(In millions)	Three Months Ended March 31 2011	2010
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net Income	$ 45	$ 149
Adjustments to reconcile net income to net cash from operating activities-		
Provision for depreciation	220	193
Amortization of regulatory assets	132	212
Nuclear fuel and lease amortization	47	41
Deferred purchased power and other costs	(58)	(77)
Deferred income taxes and investment tax credits, net	171	59
Deferred rents and lease market valuation liability	(15)	(17)
Accrued compensation and retirement benefits	(13)	(81)
Commodity derivative transactions, net	(25)	33
Pension trust contribution	(157)	
Asset impairments	31	12
Cash collateral paid	(28)	(46)
Decrease (increase) in operating assets-		
Receivables	164	2
Materials and supplies	40	(42)
Prepayments and other current assets	118	33
Increase (decrease) in operating liabilities-		
Accounts payable	(90)	(57)
Accrued taxes	(182)	7
Accrued interest	76	66
Other	15	19
Net cash provided from operating activities	491	506
CASH FLOWS FROM FINANCING ACTIVITIES:		
New financing-		
Long-term debt	217	
Redemptions and repayments-		
Long-term debt	(359)	(109)
Short-term borrowings, net	(214)	(295)
Common stock dividend payments	(190)	(168)
Other	(4)	(22)
Net cash used for financing activities	(550)	(594)
CASH FLOWS FROM INVESTING ACTIVITIES:		
Property additions	(449)	(508)

Proceeds from asset sales				114
Sales of investment securities held in trusts		969		733
Purchases of investment securities held in trusts		(993)		(755)
Customer acquisition costs		(1)		(101)
Cash investments		47		49
Cash received in Allegheny merger		590		
Other		(22)		(8)
Net cash provided from (used for) investing activities		141		(476)
Net change in cash and cash equivalents		82		(564)
Cash and cash equivalents at beginning of period		1,019		874
Cash and cash equivalents at end of period	$	1,101	$	310

SUPPLEMENTAL CASH FLOW INFORMATION:

Non-cash transaction: merger with Allegheny, common stock issued	$	4,354	$	

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

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FIRSTENERGY SOLUTIONS CORP.
CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME
(Unaudited)

	Three Months Ended March 31	
(In thousands)	**2011**	**2010**
STATEMENTS OF INCOME		
REVENUES:		
Electric sales to non-affiliates	$ 1,044,490	$ 668,685
Electric sales to affiliates	260,874	607,302
Other	85,724	112,106
Total revenues	1,391,088	1,388,093
EXPENSES:		
Fuel	343,109	328,221
Purchased power from affiliates	68,743	60,953
Purchased power from non-affiliates	296,938	450,216
Other operating expenses	495,935	304,510
Provision for depreciation	68,452	62,918
General taxes	29,105	26,746
Impairment of long-lived assets	13,800	1,833
Total expenses	1,316,082	1,235,397
OPERATING INCOME	75,006	152,696
OTHER INCOME (EXPENSE):		
Investment income	5,861	717
Miscellaneous income	19,241	3,143
Interest expense affiliates	(1,017)	(2,305)
Interest expense other	(52,960)	(49,644)
Capitalized interest	9,919	19,690
Total other expense	(18,956)	(28,399)
INCOME BEFORE INCOME TAXES	56,050	124,297
INCOME TAXES	20,116	44,371
NET INCOME	35,934	79,926

Loss attributable to noncontrolling interest		(76)		
EARNINGS AVAILABLE TO PARENT	$	36,010	$	79,926

STATEMENTS OF COMPREHENSIVE INCOME

NET INCOME	$	35,934	$	79,926
OTHER COMPREHENSIVE INCOME (LOSS):				
Pension and other postretirement benefits		1,512		(9,834)
Unrealized gain (loss) on derivative hedges		(8,879)		1,274
Change in unrealized gain on available-for-sale securities		7,807		5,028
Other comprehensive income (loss)		440		(3,532)
Income tax benefit related to other comprehensive income		(2,362)		(1,340)
Other comprehensive income (loss), net of tax		2,802		(2,192)
COMPREHENSIVE INCOME		38,736		77,734
COMPREHENSIVE LOSS ATTRIBUTABLE TO NONCONTROLLING INTEREST		(76)		
COMPREHENSIVE INCOME ATTRIBUTABLE TO PARENT	$	38,812	$	77,734

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

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FIRSTENERGY SOLUTIONS CORP.
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In thousands)	March 31, 2011	December 31, 2010
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 6,839	$ 9,281
Receivables-		
Customers, net of allowance for uncollectible accounts of $18,636 in 2011 and $16,591 in 2010	388,951	365,758
Associated companies	533,280	477,565
Other, net of allowances for uncollectible accounts of $6,702 in 2011 and $6,765 in 2010	86,711	89,550
Notes receivable from associated companies	478,418	396,770
Materials and supplies, at average cost	488,997	545,342
Derivatives	328,156	181,660
Prepayments and other	50,938	60,171
	2,362,290	2,126,097
PROPERTY, PLANT AND EQUIPMENT:		
In service	11,239,565	11,321,318
Less Accumulated provision for depreciation	4,107,542	4,024,280
	7,132,023	7,297,038
Construction work in progress	756,305	1,062,744
Property, plant and equipment held for sale, net	476,602	
	8,364,930	8,359,782
INVESTMENTS:		
Nuclear plant decommissioning trusts	1,159,903	1,145,846
Other	9,744	11,704
	1,169,647	1,157,550
DEFERRED CHARGES AND OTHER ASSETS:		
Customer intangibles	131,870	133,968
Goodwill	24,248	24,248
Property taxes	41,112	41,112
Unamortized sale and leaseback costs	90,803	73,386
Derivatives	211,223	97,603
Other	53,057	48,689
	552,313	419,006
	$ 12,449,180	$ 12,062,435

LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Currently payable long-term debt	$ 986,863	$ 1,132,135
Short-term borrowings-		
Associated companies	360,543	11,561
Other	661	
Accounts payable-		
Associated companies	499,936	466,623
Other	189,144	241,191
Accrued taxes	66,493	70,129
Derivatives	380,744	266,411
Other	224,525	251,671
	2,708,909	2,439,721
CAPITALIZATION:		
Common stockholders equity-		
Common stock, without par value, authorized 750 shares- 7 shares outstanding	1,487,565	1,490,082
Accumulated other comprehensive loss	(117,612)	(120,414)
Retained earnings	2,454,587	2,418,577
Total common stockholders equity	3,824,540	3,788,245
Noncontrolling interest	16	(504)
Total equity	3,824,556	3,787,741
Long-term debt and other long-term obligations	3,144,997	3,180,875
	6,969,553	6,968,616
NONCURRENT LIABILITIES:		
Deferred gain on sale and leaseback transaction	950,726	959,154
Accumulated deferred income taxes	117,503	57,595
Accumulated deferred investment tax credits	53,181	54,224
Asset retirement obligations	866,643	892,051
Retirement benefits	289,285	285,160
Property taxes	41,112	41,112
Lease market valuation liability	205,366	216,695
Derivatives	168,409	81,393
Other	78,493	66,714
	2,770,718	2,654,098
COMMITMENTS, GUARANTEES AND CONTINGENCIES (Note 9)		
	$ 12,449,180	$ 12,062,435

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

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FIRSTENERGY SOLUTIONS CORP.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

(In thousands)	Three Months Ended March 31 2011	2010
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net Income	$ 35,934	$ 79,926
Adjustments to reconcile net income to net cash from operating activities-		
Provision for depreciation	68,452	62,918
Nuclear fuel and lease amortization	46,653	42,118
Deferred rents and lease market valuation liability	(38,759)	(40,869)
Deferred income taxes and investment tax credits, net	61,268	37,773
Asset impairments	18,791	11,439
Commodity derivative transactions, net	(35,293)	32,900
Cash collateral paid	(27,063)	(21,411)
Decrease (increase) in operating assets-		
Receivables	(76,069)	(158,288)
Materials and supplies	60,633	(8,700)
Prepayments and other current assets	8,728	13,516
Increase (decrease) in operating liabilities-		
Accounts payable	(18,734)	(41,057)
Accrued taxes	(3,164)	(16,300)
Accrued interest	(11,845)	(14,930)
Other	4,093	12,069
Net cash provided from (used for) operating activities	93,625	(8,896)
CASH FLOWS FROM FINANCING ACTIVITIES:		
New financing-		
Long-term debt	150,190	
Short-term borrowings, net	349,643	
Redemptions and repayments-		
Long-term debt	(331,428)	(1,278)
Short-term borrowings, net		(9,237)
Other	(1,017)	(731)
Net cash provided from (used for) financing activities	167,388	(11,246)
CASH FLOWS FROM INVESTING ACTIVITIES:		
Property additions	(159,006)	(301,603)
Proceeds from asset sales		114,272
Sales of investment securities held in trusts	215,620	272,094
Purchases of investment securities held in trusts	(230,912)	(284,888)
Loans from (to) associated companies, net	(81,647)	321,680

Customer acquisition costs	(1,103)	(100,615)
Other	(6,407)	(799)
Net cash provided from (used for) investing activities	(263,455)	20,141
Net change in cash and cash equivalents	(2,442)	(1)
Cash and cash equivalents at beginning of period	9,281	12
Cash and cash equivalents at end of period	$ 6,839	$ 11

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

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OHIO EDISON COMPANY
CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME
(Unaudited)

(In thousands)	Three Months Ended March 31 2011	2010
STATEMENTS OF INCOME		
REVENUES:		
Electric sales	$ 363,831	$ 479,925
Excise and gross receipts tax collections	28,195	28,475
Total revenues	392,026	508,400
EXPENSES:		
Purchased power from affiliates	93,262	153,677
Purchased power from non-affiliates	60,379	94,231
Other operating costs	101,462	88,855
Provision for depreciation	21,876	21,880
Amortization of regulatory assets, net	774	29,345
General taxes	49,426	47,492
Total expenses	327,179	435,480
OPERATING INCOME	64,847	72,920
OTHER INCOME (EXPENSE):		
Investment income	4,308	5,244
Miscellaneous income (expense)	290	(292)
Interest expense	(22,145)	(22,310)
Capitalized interest	331	208
Total other expense	(17,216)	(17,150)
INCOME BEFORE INCOME TAXES	47,631	55,770
INCOME TAXES	17,491	19,609
NET INCOME	30,140	36,161
Income attributable to noncontrolling interest	116	132

EARNINGS AVAILABLE TO PARENT	$	30,024	$	36,029

STATEMENTS OF COMPREHENSIVE INCOME

NET INCOME	$	30,140	$	36,161
OTHER COMPREHENSIVE INCOME (LOSS):				
Pension and other postretirement benefits		339		4,015
Change in unrealized gain on available-for-sale securities		(22)		291
Other comprehensive income		317		4,306
Income tax expense (benefit) related to other comprehensive income		(1,496)		693
Other comprehensive income, net of tax		1,813		3,613
COMPREHENSIVE INCOME		31,953		39,774
COMPREHENSIVE INCOME ATTRIBUTABLE TO NONCONTROLLING INTEREST		116		132
COMPREHENSIVE INCOME AVAILABLE TO PARENT	$	31,837	$	39,642

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

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OHIO EDISON COMPANY
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In thousands)	**March 31, 2011**	**December 31, 2010**
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 345,030	$ 420,489
Receivables-		
Customers (net of allowance for uncollectible accounts of $3,774 in 2011 and $4,086 in 2010)	158,146	176,591
Associated companies	74,125	118,135
Other	17,290	12,232
Notes receivable from associated companies	16,762	16,957
Prepayments and other	29,366	6,393
	640,719	750,797
UTILITY PLANT:		
In service	3,156,648	3,136,623
Less Accumulated provision for depreciation	1,217,827	1,207,745
	1,938,821	1,928,878
Construction work in progress	48,302	45,103
	1,987,123	1,973,981
OTHER PROPERTY AND INVESTMENTS:		
Investment in lease obligation bonds	190,340	190,420
Nuclear plant decommissioning trusts	126,826	127,017
Other	94,604	95,563
	411,770	413,000
DEFERRED CHARGES AND OTHER ASSETS:		
Regulatory assets	385,005	400,322
Pension assets	59,104	28,596
Property taxes	71,331	71,331
Unamortized sale and leaseback costs	28,877	30,126
Other	16,007	17,634
	560,324	548,009
	$ 3,599,936	$ 3,685,787
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		

Currently payable long-term debt	$ 1,424	$ 1,419
Short-term borrowings-		
Associated companies	103,071	142,116
Other	320	320
Accounts payable-		
Associated companies	96,003	99,421
Other	25,515	29,639
Accrued taxes	68,415	78,707
Accrued interest	25,334	25,382
Other	105,315	74,947
	425,397	451,951
CAPITALIZATION:		
Common stockholders equity-		
Common stock, without par value, authorized 175,000,000 shares- 60 shares outstanding	951,802	951,866
Accumulated other comprehensive loss	(177,263)	(179,076)
Retained earnings	71,645	141,621
Total common stockholders equity	846,184	914,411
Noncontrolling interest	5,796	5,680
Total equity	851,980	920,091
Long-term debt and other long-term obligations	1,152,171	1,152,134
	2,004,151	2,072,225
NONCURRENT LIABILITIES:		
Accumulated deferred income taxes	719,979	696,410
Accumulated deferred investment tax credits	9,799	10,159
Retirement benefits	182,461	183,712
Asset retirement obligations	69,793	74,456
Other	188,356	196,874
	1,170,388	1,161,611
COMMITMENTS AND CONTINGENCIES (Note 9)		
	$ 3,599,936	$ 3,685,787

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

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OHIO EDISON COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

(In thousands)	Three Months Ended March 31 2011	2010
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net Income	$ 30,140	$ 36,161
Adjustments to reconcile net income to net cash from operating activities-		
Provision for depreciation	21,876	21,880
Amortization of regulatory assets, net	774	29,345
Purchased power cost recovery reconciliation	(4,926)	(5,908)
Amortization of lease costs	32,933	32,934
Deferred income taxes and investment tax credits, net	26,682	(2,489)
Accrued compensation and retirement benefits	(7,944)	(12,160)
Pension trust contribution	(27,000)	
Decrease (increase) in operating assets-		
Receivables	82,291	65,141
Prepayments and other current assets	(22,973)	(21,802)
Decrease in operating liabilities-		
Accounts payable	(19,625)	(35,461)
Accrued taxes	(10,305)	(15,849)
Accrued interest	(48)	(226)
Other	2,438	9,647
Net cash provided from operating activities	104,313	101,213
CASH FLOWS FROM FINANCING ACTIVITIES:		
Redemptions and repayments-		
Long-term debt	(110)	(1,363)
Short-term borrowings, net	(39,045)	(92,863)
Common stock dividend payments	(100,000)	(250,000)
Other		(113)
Net cash used for financing activities	(139,155)	(344,339)
CASH FLOWS FROM INVESTING ACTIVITIES:		
Property additions	(37,651)	(35,680)
Sales of investment securities held in trusts	7,972	2,424
Purchases of investment securities held in trusts	(8,896)	(2,971)
Loan repayments from associated companies, net	195	14,469
Cash investments	(136)	(384)
Other	(2,101)	1,773
Net cash used for investing activities	(40,617)	(20,369)

Net change in cash and cash equivalents		(75,459)		(263,495)
Cash and cash equivalents at beginning of period		420,489		324,175
Cash and cash equivalents at end of period	$	345,030	$	60,680

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

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THE CLEVELAND ELECTRIC ILLUMINATING COMPANY
CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME
(Unaudited)

	Three Months Ended March 31	
(In thousands)	**2011**	**2010**
STATEMENTS OF INCOME		
REVENUES:		
Electric sales	$ 206,742	$ 312,497
Excise tax collections	18,145	17,573
Total revenues	224,887	330,070
EXPENSES:		
Purchased power from affiliates	46,168	109,393
Purchased power from non-affiliates	18,220	37,398
Other operating expenses	35,036	31,235
Provision for depreciation	18,426	18,111
Amortization of regulatory assets	23,370	45,139
General taxes	40,212	38,489
Total expenses	181,432	279,765
OPERATING INCOME	43,455	50,305
OTHER INCOME (EXPENSE):		
Investment income	6,597	7,547
Miscellaneous income	636	581
Interest expense	(33,078)	(33,621)
Capitalized interest	27	26
Total other expense	(25,818)	(25,467)
INCOME BEFORE INCOME TAXES	17,637	24,838
INCOME TAXES	4,436	10,843
NET INCOME	13,201	13,995
Income attributable to noncontrolling interest	366	419

EARNINGS AVAILABLE TO PARENT	$	12,835	$	13,576

STATEMENTS OF COMPREHENSIVE INCOME

NET INCOME	$	13,201	$	13,995
OTHER COMPREHENSIVE INCOME (LOSS):				
Pension and other postretirement benefits		2,967		(22,585)
Income tax benefit related to other comprehensive income		(462)		(8,277)
Other comprehensive income (loss), net of tax		3,429		(14,308)
COMPREHENSIVE INCOME (LOSS)		16,630		(313)
COMPREHENSIVE INCOME ATTRIBUTABLE TO NONCONTROLLING INTEREST		366		419
TOTAL COMPREHENSIVE INCOME (LOSS) AVAILABLE TO PARENT	$	16,264	$	(732)

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

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THE CLEVELAND ELECTRIC ILLUMINATING COMPANY
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In thousands)	March 31, 2011	December 31, 2010
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 30,244	$ 238
Receivables-		
Customers (less allowance for doubtful accounts of $3,018 in 2011 and $4,589 in 2010, respectively)	107,418	183,744
Associated companies	34,819	77,047
Other	4,848	11,544
Notes receivable from associated companies	22,704	23,236
Prepayments and other	13,894	3,656
	213,927	299,465
UTILITY PLANT:		
In service	2,407,827	2,396,893
Less Accumulated provision for depreciation	937,105	932,246
	1,470,722	1,464,647
Construction work in progress	48,572	38,610
	1,519,294	1,503,257
OTHER PROPERTY AND INVESTMENTS:		
Investment in lessor notes	286,747	340,029
Other	10,035	10,074
	296,782	350,103
DEFERRED CHARGES AND OTHER ASSETS:		
Goodwill	1,688,521	1,688,521
Regulatory assets	337,189	370,403
Property taxes	80,614	80,614
Other	11,176	11,486
	2,117,500	2,151,024
	$ 4,147,503	$ 4,303,849
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		

Currently payable long-term debt	$ 174	$ 161
Short-term borrowings-		
Associated companies	23,303	105,996
Accounts payable-		
Associated companies	43,564	32,020
Other	8,811	14,947
Accrued taxes	75,771	84,668
Accrued interest	39,256	18,555
Other	40,862	44,569
	231,741	300,916
CAPITALIZATION:		
Common stockholder s equity-		
Common stock, without par value, authorized 105,000,000 shares- 67,930,743 shares outstanding	886,995	887,087
Accumulated other comprehensive loss	(149,758)	(153,187)
Retained earnings	531,741	568,906
Total common stockholder s equity	1,268,978	1,302,806
Noncontrolling interest	14,886	18,017
Total equity	1,283,864	1,320,823
Long-term debt and other long-term obligations	1,831,011	1,852,530
	3,114,875	3,173,353
NONCURRENT LIABILITIES:		
Accumulated deferred income taxes	631,507	622,771
Accumulated deferred investment tax credits	10,784	10,994
Retirement benefits	60,682	95,654
Other	97,914	100,161
	800,887	829,580
COMMITMENTS, GUARANTEES AND CONTINGENCIES (Note 9)		
	$ 4,147,503	$ 4,303,849

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

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THE CLEVELAND ELECTRIC ILLUMINATING COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

(In thousands)	Three Months Ended March 31 2011	2010
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net Income	$ 13,201	$ 13,995
Adjustments to reconcile net income to net cash from operating activities-		
Provision for depreciation	18,426	18,111
Amortization of regulatory assets, net	23,370	45,139
Deferred income taxes and investment tax credits, net	4,140	(13,627)
Accrued compensation and retirement benefits	2,158	2,282
Accrued regulatory obligations	(863)	(26)
Pension trust contribution	(35,000)	
Decrease (increase) in operating assets-		
Receivables	136,887	70,633
Prepayments and other current assets	(10,236)	(9,133)
Increase (decrease) in operating liabilities-		
Accounts payable	5,408	(14,387)
Accrued taxes	(8,898)	(16,616)
Accrued interest	20,701	20,795
Other	(3,870)	(2,636)
Net cash provided from operating activities	165,424	114,530
CASH FLOWS FROM FINANCING ACTIVITIES:		
Redemptions and repayments-		
Long-term debt	(36)	(26)
Short-term borrowings, net	(104,228)	(126,334)
Common stock dividend payments	(50,000)	(100,000)
Other	(3,497)	(3,365)
Net cash used for financing activities	(157,761)	(229,725)
CASH FLOWS FROM INVESTING ACTIVITIES:		
Property additions	(29,334)	(19,735)
Loans to associated companies, net	532	1,426
Redemptions of lessor notes	53,282	48,606
Other	(2,137)	(1,085)
Net cash provided from investing activities	22,343	29,212
Net change in cash and cash equivalents	30,006	(85,983)

Cash and cash equivalents at beginning of period		238		86,230
Cash and cash equivalents at end of period	$	30,244	$	247

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

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THE TOLEDO EDISON COMPANY
CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME
(Unaudited)

(In thousands)	Three Months Ended March 31 2011	2010
STATEMENTS OF INCOME		
REVENUES:		
Electric sales	$ 106,325	$ 125,431
Excise tax collections	7,302	7,041
Total revenues	113,627	132,472
EXPENSES:		
Purchased power from affiliates	35,517	54,618
Purchased power from non-affiliates	13,988	18,491
Other operating expenses	36,587	25,545
Provision for depreciation	7,931	7,950
Deferral of regulatory assets, net	(11,478)	(8,499)
General taxes	14,452	13,461
Total expenses	96,997	111,566
OPERATING INCOME	16,630	20,906
OTHER INCOME (EXPENSE):		
Investment income	2,922	3,800
Miscellaneous expense	(1,629)	(1,406)
Interest expense	(10,443)	(10,487)
Capitalized interest	102	78
Total other expense	(9,048)	(8,015)
INCOME BEFORE INCOME TAXES	7,582	12,891
INCOME TAXES	1,735	5,382
NET INCOME	5,847	7,509
Income attributable to noncontrolling interest	2	3

EARNINGS AVAILABLE TO PARENT	$	5,845	$	7,506

STATEMENTS OF COMPREHENSIVE INCOME

NET INCOME	$	5,847	$	7,509
OTHER COMPREHENSIVE INCOME:				
Pension and other postretirement benefits		592		296
Change in unrealized gain on available-for-sale securities		1,305		369
Other comprehensive income		1,897		665
Income tax expense related to other comprehensive income		334		170
Other comprehensive income, net of tax		1,563		495
COMPREHENSIVE INCOME		7,410		8,004
COMPREHENSIVE INCOME ATTRIBUTABLE TO NONCONTROLLING INTEREST		2		3
COMPREHENSIVE INCOME AVAILABLE TO PARENT	$	7,408	$	8,001

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

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THE TOLEDO EDISON COMPANY
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In thousands)	March 31, 2011	December 31, 2010
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 150,014	$ 149,262
Receivables-		
Customers (net of allowance for uncollectible accounts of $1,209 in 2011 and $1 in 2010)	45,749	29
Associated companies	56,913	31,777
Other (net of allowance for uncollectible accounts of $343 in 2011 and $330 in 2010)	18,752	18,464
Notes receivable from associated companies	35,489	96,765
Prepayments and other	8,302	2,306
	315,219	298,603
UTILITY PLANT:		
In service	952,874	947,203
Less Accumulated provision for depreciation	449,791	446,401
	503,083	500,802
Construction work in progress	12,647	12,604
	515,730	513,406
OTHER PROPERTY AND INVESTMENTS:		
Investment in lessor notes	82,133	103,872
Nuclear plant decommissioning trusts	77,141	75,558
Other	1,469	1,492
	160,743	180,922
DEFERRED CHARGES AND OTHER ASSETS:		
Goodwill	500,576	500,576
Regulatory assets	83,544	72,059
Pension assets	24,427	
Property taxes	24,990	24,990
Other	36,167	23,750
	669,704	621,375
	$ 1,661,396	$ 1,614,306

LIABILITIES AND CAPITALIZATION

CURRENT LIABILITIES:		
Currently payable long-term debt	$ 191	$ 199
Accounts payable-		
Associated companies	36,055	17,168
Other	5,238	7,351
Accrued taxes	23,043	24,401
Accrued interest	15,983	5,931
Lease market valuation liability	36,900	36,900
Other	54,905	23,145
	172,315	115,095
CAPITALIZATION:		
Common stockholders equity-		
Common stock, $5 par value, authorized 60,000,000 shares- 29,402,054 shares outstanding	147,010	147,010
Other paid-in capital	178,122	178,182
Accumulated other comprehensive loss	(47,620)	(49,183)
Retained earnings	108,379	117,534
Total common stockholders equity	385,891	393,543
Noncontrolling interest	2,591	2,589
Total equity	388,482	396,132
Long-term debt and other long-term obligations	600,508	600,493
	988,990	996,625
NONCURRENT LIABILITIES:		
Accumulated deferred income taxes	157,797	132,019
Accumulated deferred investment tax credits	5,822	5,930
Retirement benefits	51,253	71,486
Asset retirement obligations	29,245	28,762
Lease market valuation liability	190,075	199,300
Other	65,899	65,089
	500,091	502,586
COMMITMENTS AND CONTINGENCIES (Note 9)		
	$ 1,661,396	$ 1,614,306

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

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THE TOLEDO EDISON COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Three Months Ended March 31	
(In thousands)	**2011**	**2010**
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net Income	$ 5,847	$ 7,509
Adjustments to reconcile net income to net cash from operating activities-		
Provision for depreciation	7,931	7,950
Deferral of regulatory assets, net	(11,478)	(8,499)
Deferred rents and lease market valuation liability	6,141	6,141
Deferred income taxes and investment tax credits, net	25,046	11,287
Accrued compensation and retirement benefits	(142)	837
Pension trust contribution	(45,000)	
Decrease (increase) in operating assets-		
Receivables	(70,694)	45,376
Prepayments and other current assets	(5,996)	(4,569)
Increase (decrease) in operating liabilities-		
Accounts payable	16,774	(35,414)
Accrued taxes	(1,358)	(4,933)
Accrued interest	10,052	10,050
Other	6,098	(4,578)
Net cash provided from (used for) operating activities	(56,779)	31,157
CASH FLOWS FROM FINANCING ACTIVITIES:		
Redemptions and repayments-		
Long-term debt	(56)	(56)
Short-term borrowings, net		(225,975)
Common stock dividend payments	(15,000)	(130,000)
Other		(2)
Net cash used for financing activities	(15,056)	(356,033)
CASH FLOWS FROM INVESTING ACTIVITIES:		
Property additions	(9,507)	(9,597)
Loan repayments from (loans to) associated companies, net	61,276	(33,587)
Redemptions of lessor notes	21,739	20,509
Sales of investment securities held in trusts	13,883	31,067
Purchases of investment securities held in trusts	(14,338)	(31,705)
Other	(466)	(1,227)
Net cash provided from (used for) investing activities	72,587	(24,540)

Net change in cash and cash equivalents		752		(349,416)
Cash and cash equivalents at beginning of period		149,262		436,712
Cash and cash equivalents at end of period	$	150,014	$	87,296

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

JERSEY CENTRAL POWER & LIGHT COMPANY
CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME
(Unaudited)

	Three Months Ended March 31	
(In thousands)	**2011**	**2010**
STATEMENTS OF INCOME		
REVENUES:		
Electric sales	$ 634,023	$ 691,392
Excise tax collections	12,487	12,352
Total revenues	646,510	703,744
EXPENSES:		
Purchased power	370,168	414,016
Other operating expenses	86,079	95,660
Provision for depreciation	25,314	27,971
Amortization of regulatory assets, net	81,587	69,448
General taxes	17,411	16,436
Total expenses	580,559	623,531
OPERATING INCOME	65,951	80,213
OTHER INCOME (EXPENSE):		
Miscellaneous income	1,910	1,833
Interest expense	(30,657)	(29,423)
Capitalized interest	427	133
Total other expense	(28,320)	(27,457)
INCOME BEFORE INCOME TAXES	37,631	52,756
INCOME TAXES	18,078	23,530
NET INCOME	$ 19,553	$ 29,226
STATEMENTS OF COMPREHENSIVE INCOME		
NET INCOME	$ 19,553	$ 29,226

OTHER COMPREHENSIVE INCOME:				
Pension and other postretirement benefits		4,221		15,928
Unrealized gain on derivative hedges		69		69
Other comprehensive income		4,290		15,997
Income tax expense related to other comprehensive income		1,590		6,558
Other comprehensive income, net of tax		2,700		9,439
COMPREHENSIVE INCOME	$	22,253	$	38,665

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

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JERSEY CENTRAL POWER & LIGHT COMPANY
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In thousands)	March 31, 2011	December 31, 2010
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 1	$ 4
Receivables-		
Customers (net of allowance for uncollectible accounts of $3,842 in 2011 and $3,769 in 2010)	268,171	323,044
Associated companies	27,144	53,780
Other	21,269	26,119
Notes receivable associated companies	298,274	177,228
Prepaid taxes	10,968	10,889
Other	16,357	12,654
	642,184	603,718
UTILITY PLANT:		
In service	4,579,753	4,562,781
Less Accumulated provision for depreciation	1,667,017	1,656,939
	2,912,736	2,905,842
Construction work in progress	78,819	63,535
	2,991,555	2,969,377
OTHER PROPERTY AND INVESTMENTS:		
Nuclear fuel disposal trust	206,833	207,561
Nuclear plant decommissioning trusts	190,424	181,851
Other	2,111	2,104
	399,368	391,516
DEFERRED CHARGES AND OTHER ASSETS:		
Goodwill	1,810,936	1,810,936
Regulatory assets	460,156	513,395
Other	25,243	27,938
	2,296,335	2,352,269
	$ 6,329,442	$ 6,316,880
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Currently payable long-term debt	$ 32,855	$ 32,402
Accounts payable-		

Associated companies	16,983	28,571
Other	123,814	158,442
Accrued compensation and benefits	33,415	35,232
Customer deposits	23,494	23,385
Accrued taxes	15,142	2,509
Accrued interest	29,926	18,111
Other	25,663	22,263
	301,292	320,915
CAPITALIZATION:		
Common stockholders equity-		
Common stock, $10 par value, authorized 16,000,000 shares- 13,628,447 shares outstanding	136,284	136,284
Other paid-in capital	2,508,754	2,508,874
Accumulated other comprehensive loss	(250,842)	(253,542)
Retained earnings	246,723	227,170
Total common stockholder s equity	2,640,919	2,618,786
Long-term debt and other long-term obligations	1,762,365	1,769,849
	4,403,284	4,388,635
NONCURRENT LIABILITIES:		
Accumulated deferred income taxes	729,478	715,527
Power purchase contract liability	238,677	233,492
Nuclear fuel disposal costs	196,843	196,768
Retirement benefits	175,175	182,364
Asset retirement obligations	110,050	108,297
Other	174,643	170,882
	1,624,866	1,607,330
COMMITMENTS, GUARANTEES AND CONTINGENCIES (Note 9)		
	$ 6,329,442	$ 6,316,880

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

JERSEY CENTRAL POWER & LIGHT COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

(In thousands)	**Three Months Ended March 31 2011**	**2010**
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net Income	$ 19,553	$ 29,226
Adjustments to reconcile net income to net cash from operating activities-		
Provision for depreciation	25,314	27,971
Amortization of regulatory assets, net	81,587	69,448
Deferred purchased power and other costs	(26,516)	(32,775)
Deferred income taxes and investment tax credits, net	25,560	(2,082)
Accrued compensation and retirement benefits	(4,776)	(5,847)
Cash collateral returned to suppliers	(250)	(23,400)
Decrease (increase) in operating assets-		
Receivables	86,359	33,257
Prepayments and other current assets	(1,687)	16,472
Increase (decrease) in operating liabilities-		
Accounts payable	(61,612)	(40,992)
Accrued taxes	12,631	50,857
Accrued interest	11,815	11,816
Tax collections payable	7,084	14,544
Other	7,448	466
Net cash provided from operating activities	182,510	148,961
CASH FLOWS FROM FINANCING ACTIVITIES:		
Redemptions and repayments-		
Long-term debt	(7,190)	(6,773)
Common stock dividend payments		(90,000)
Net cash used for financing activities	(7,190)	(96,773)
CASH FLOWS FROM INVESTING ACTIVITIES:		
Property additions	(47,604)	(37,338)
Loans to associated companies, net	(121,046)	(7,620)
Sales of investment securities held in trusts	217,103	190,198
Purchases of investment securities held in trusts	(221,695)	(194,748)
Other	(2,081)	(2,706)
Net cash used for investing activities	(175,323)	(52,214)
Net change in cash and cash equivalents	(3)	(26)

Cash and cash equivalents at beginning of period	4	27
Cash and cash equivalents at end of period	$ 1	$ 1

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

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METROPOLITAN EDISON COMPANY
CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME
(Unaudited)

	Three Months Ended March 31	
(In thousands)	**2011**	**2010**
STATEMENTS OF INCOME		
REVENUES:		
Electric sales	$ 338,416	$ 451,560
Gross receipts tax collections	18,800	21,567
Total revenues	357,216	473,127
EXPENSES:		
Purchased power from affiliates	49,889	161,080
Purchased power from non-affiliates	153,043	91,928
Other operating expenses	47,232	101,983
Provision for depreciation	12,423	12,758
Amortization of regulatory assets, net	32,094	48,800
General taxes	22,150	21,740
Total expenses	316,831	438,289
OPERATING INCOME	40,385	34,838
OTHER INCOME (EXPENSE):		
Interest income	93	1,217
Miscellaneous income	970	2,173
Interest expense	(13,057)	(13,773)
Capitalized interest	147	126
Total other expense	(11,847)	(10,257)
INCOME BEFORE INCOME TAXES	28,538	24,581
INCOME TAXES	5,951	12,266
NET INCOME	$ 22,587	$ 12,315

STATEMENTS OF COMPREHENSIVE INCOME

NET INCOME	$ 22,587	$ 12,315
OTHER COMPREHENSIVE INCOME:		
Pension and other postretirement benefits	1,963	9,709
Unrealized gain on derivative hedges	84	84
Other comprehensive income	2,047	9,793
Income tax expense related to other comprehensive income	763	4,177
Other comprehensive income, net of tax	1,284	5,616
COMPREHENSIVE INCOME	$ 23,871	$ 17,931

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

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METROPOLITAN EDISON COMPANY
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In thousands)	March 31, 2011	December 31, 2010
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 117	$ 243,220
Receivables-		
Customers (less allowance for doubtful accounts of $3,841 in 2011 and $3,868 in 2010, respectively)	159,801	178,522
Associated companies	23,110	24,920
Other	16,836	13,007
Notes receivable from associated companies	9,542	11,028
Prepaid taxes	40,883	343
Other	1,973	2,289
	252,262	473,329
UTILITY PLANT:		
In service	2,260,156	2,247,853
Less Accumulated provision for depreciation	852,326	846,003
	1,407,830	1,401,850
Construction work in progress	27,714	23,663
	1,435,544	1,425,513
OTHER PROPERTY AND INVESTMENTS:		
Nuclear plant decommissioning trusts	303,906	289,328
Other	881	884
	304,787	290,212
DEFERRED CHARGES AND OTHER ASSETS:		
Goodwill	416,499	416,499
Regulatory assets	285,300	295,856
Power purchase contract asset	107,055	111,562
Other	51,939	31,699
	860,793	855,616
	$ 2,853,386	$ 3,044,670

LIABILITIES AND CAPITALIZATION

CURRENT LIABILITIES:		
Currently payable long-term debt	$ 42,450	$ 28,760
Short-term borrowings-		
Associated companies	109,709	124,079
Accounts payable-		
Associated companies	35,758	33,942
Other	47,450	29,862
Accrued taxes	14,514	60,856
Accrued interest	11,738	16,114
Other	29,543	29,278
	291,162	322,891
CAPITALIZATION:		
Common stockholders equity-		
Common stock, without par value, authorized 900,000 shares- 740,905 shares outstanding	1,046,970	1,197,076
Accumulated other comprehensive loss	(141,099)	(142,383)
Retained earnings	29,994	32,406
Total common stockholder s equity	935,865	1,087,099
Long-term debt and other long-term obligations	705,125	718,860
	1,640,990	1,805,959
NONCURRENT LIABILITIES:		
Accumulated deferred income taxes	481,530	473,009
Accumulated deferred investment tax credits	6,761	6,866
Nuclear fuel disposal costs	44,465	44,449
Asset retirement obligations	195,883	192,659
Retirement benefits	22,405	29,121
Power purchase contract liability	118,123	116,027
Other	52,067	53,689
	921,234	915,820
COMMITMENTS AND CONTINGENCIES (Note 9)		
	$ 2,853,386	$ 3,044,670

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

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METROPOLITAN EDISON COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

(In thousands)	Three Months Ended March 31 2011	2010
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net Income	$ 22,587	$ 12,315
Adjustments to reconcile net income to net cash from operating activities-		
Provision for depreciation	12,423	12,758
Amortization of regulatory assets, net	32,094	48,800
Deferred costs recoverable as regulatory assets	(12,082)	(18,276)
Deferred income taxes and investment tax credits, net	1,304	(10,308)
Accrued compensation and retirement benefits	(1,433)	(2,527)
Cash collateral returned from (paid to) suppliers	1,000	(700)
Pension trust contributions	(35,000)	
Decrease (increase) in operating assets-		
Receivables	16,702	(5,083)
Prepayments and other current assets	(40,225)	(52,040)
Increase (decrease) in operating liabilities-		
Accounts payable	15,749	(7,279)
Accrued taxes	(46,006)	19,960
Accrued interest	(4,376)	(5,674)
Other	6,337	2,373
Net cash used for operating activities	(30,926)	(5,681)
CASH FLOWS FROM FINANCING ACTIVITIES:		
New financing-		
Short-term borrowings, net		48,793
Redemptions and repayments-		
Long-term debt		(100,000)
Short-term borrowings, net	(14,369)	
Common stock	(150,000)	
Common stock dividend payments	(25,000)	
Net cash used for financing activities	(189,369)	(51,207)
CASH FLOWS FROM INVESTING ACTIVITIES:		
Property additions	(21,126)	(25,526)
Sales of investment securities held in trusts	335,860	143,713
Purchases of investment securities held in trusts	(337,632)	(146,056)
Loans repayments from associated companies, net	1,486	85,383
Other	(1,396)	(618)

Net cash provided from (used for) investing activities	(22,808)	56,896
Net increase (decrease) in cash and cash equivalents	(243,103)	8
Cash and cash equivalents at beginning of period	243,220	120
Cash and cash equivalents at end of period	$ 117	$ 128

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

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PENNSYLVANIA ELECTRIC COMPANY
CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME
(Unaudited)

(In thousands)	Three Months Ended March 31 2011	Three Months Ended March 31 2010
STATEMENTS OF INCOME		
REVENUES:		
Electric sales	$ 308,316	$ 385,936
Gross receipts tax collections	16,529	17,524
Total revenues	324,845	403,460
EXPENSES:		
Purchased power from affiliates	47,484	168,400
Purchased power from non-affiliates	141,436	91,423
Other operating expenses	41,328	72,394
Provision for depreciation	14,573	14,682
Amortization (deferral) of regulatory assets, net	13,007	(9,966)
General taxes	20,736	16,534
Total expenses	278,564	353,467
OPERATING INCOME	46,281	49,993
OTHER INCOME (EXPENSE):		
Miscellaneous income	25	1,613
Interest expense	(17,234)	(17,290)
Capitalized interest	22	140
Total other expense	(17,187)	(15,537)
INCOME BEFORE INCOME TAXES	29,094	34,456
INCOME TAXES	11,788	17,157
NET INCOME	$ 17,306	$ 17,299
STATEMENTS OF COMPREHENSIVE INCOME		
NET INCOME	$ 17,306	$ 17,299

OTHER COMPREHENSIVE INCOME:				
Pension and other postretirement benefits		1,585		8,547
Unrealized gain on derivative hedges		16		16
Other comprehensive income		1,601		8,563
Income tax expense related to other comprehensive income		555		3,284
Other comprehensive income, net of tax		1,046		5,279
COMPREHENSIVE INCOME	$	18,352	$	22,578

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

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PENNSYLVANIA ELECTRIC COMPANY
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In thousands)	March 31, 2011	December 31, 2010
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 3	$ 5
Receivables-		
Customers (net of allowance for uncollectible accounts of $3,395 in 2011 and $3,369 in 2010)	139,058	148,864
Associated companies	16,921	54,052
Other	12,142	11,314
Notes receivable from associated companies	12,334	14,404
Prepaid taxes	47,126	14,026
Other	1,843	1,592
	229,427	244,257
UTILITY PLANT:		
In service	2,545,211	2,532,629
Less Accumulated provision for depreciation	939,247	935,259
	1,605,964	1,597,370
Construction work in progress	40,799	30,505
	1,646,763	1,627,875
OTHER PROPERTY AND INVESTMENTS:		
Nuclear plant decommissioning trusts	159,999	152,928
Non-utility generation trusts	80,275	80,244
Other	294	297
	240,568	233,469
DEFERRED CHARGES AND OTHER ASSETS:		
Goodwill	768,628	768,628
Regulatory assets	179,092	163,407
Power purchase contract asset	4,169	5,746
Other	15,140	19,287
	967,029	957,068
	$ 3,083,787	$ 3,062,669

LIABILITIES AND CAPITALIZATION

CURRENT LIABILITIES:		
Currently payable long-term debt	$ 45,000	$ 45,000
Short-term borrowings-		
Associated companies	90,363	101,338
Accounts payable-		
Associated companies	41,231	35,626
Other	33,125	41,420
Accrued taxes	4,262	5,075
Accrued interest	24,069	17,378
Other	23,467	22,541
	261,517	268,378
CAPITALIZATION:		
Common stockholders equity-		
Common stock, $20 par value, authorized 5,400,000 shares- 4,427,577 shares outstanding	88,552	88,552
Other paid-in capital	913,439	913,519
Accumulated other comprehensive loss	(162,480)	(163,526)
Retained earnings	58,299	60,993
Total common stockholder s equity	897,810	899,538
Long-term debt and other long-term obligations	1,072,339	1,072,262
	1,970,149	1,971,800
NONCURRENT LIABILITIES:		
Accumulated deferred income taxes	393,088	371,877
Retirement benefits	187,888	187,621
Power purchase contract liability	121,558	116,972
Asset retirement obligations	99,773	98,132
Other	49,814	47,889
	852,121	822,491
COMMITMENTS, GUARANTEES AND CONTINGENCIES (Note 9)		
	$ 3,083,787	$ 3,062,669

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

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PENNSYLVANIA ELECTRIC COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

(In thousands)	Three Months Ended March 31 2011	2010
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net Income	$ 17,306	$ 17,299
Adjustments to reconcile net income to net cash from operating activities-		
Provision for depreciation	14,573	14,682
Amortization (deferral) of regulatory assets, net	13,007	(9,966)
Deferred costs recoverable as regulatory assets	(17,771)	(20,461)
Deferred income taxes and investment tax credits, net	16,648	21,772
Accrued compensation and retirement benefits	1,551	(169)
Cash collateral paid, net	(2,124)	(400)
Decrease (increase) in operating assets-		
Receivables	46,100	(4,641)
Prepayments and other current assets	(33,350)	(50,186)
Increase (decrease) in operating liabilities-		
Accounts payable	(8,534)	(1,348)
Accrued taxes	(813)	(2,142)
Accrued interest	6,691	6,882
Other	10,204	7,162
Net cash provided from (used for) operating activities	63,488	(21,516)
CASH FLOWS FROM FINANCING ACTIVITIES:		
New financing-		
Short-term borrowings, net		51,334
Redemptions and repayments-		
Short-term borrowings, net	(10,975)	
Common stock dividend payments	(20,000)	
Other	26	(6)
Net cash provided from (used for) financing activities	(30,949)	51,328
CASH FLOWS FROM INVESTING ACTIVITIES:		
Property additions	(31,128)	(27,388)
Loan repayments from associated companies, net	2,070	279
Sales of investment securities held in trusts	178,927	93,057
Purchases of investment securities held in trusts	(180,411)	(94,464)
Other	(1,999)	(1,298)
Net cash used for investing activities	(32,541)	(29,814)

Net change in cash and cash equivalents		(2)		(2)
Cash and cash equivalents at beginning of period		5		14
Cash and cash equivalents at end of period	$	3	$	12

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

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COMBINED NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

1. ORGANIZATION AND BASIS OF PRESENTATION

FirstEnergy is a diversified energy company that holds, directly or indirectly, all of the outstanding common stock of its principal subsidiaries: OE, CEI, TE, Penn (a wholly owned subsidiary of OE), ATSI, JCP&L, Met-Ed, Penelec, FENOC, AE and its principal subsidiaries (AE Supply, AGC, MP, PE, WP and TrAIL Company), FES and its subsidiaries FGCO and NGC, and FESC. AE merged with a subsidiary of FirstEnergy on February 25, 2011, with AE remaining as the surviving corporation and becoming a wholly-owned subsidiary of FirstEnergy (See Note 2, Merger).

FirstEnergy and its subsidiaries follow GAAP and comply with the regulations, orders, policies and practices prescribed by the SEC, the FERC, the NERC and, as applicable, the PUCO, the PPUC, the MDPSC, the NYPSC, the WVPSC and the NJBPU. The preparation of financial statements in conformity with GAAP requires management to make periodic estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses and disclosure of contingent assets and liabilities. Actual results could differ from these estimates. The reported results of operations are not indicative of results of operations for any future period. In preparing the financial statements, FirstEnergy and its subsidiaries have evaluated events and transactions for potential recognition or disclosure through the date the financial statements were issued.

These statements should be read in conjunction with the financial statements and notes included in the combined Annual Report on Form 10-K for the year ended December 31, 2010 for FirstEnergy, FES and the Utility Registrants, as applicable, and the Current Report on Form 8-K filed by FirstEnergy on February 25, 2011, as amended on April 19, 2011. The consolidated unaudited financial statements of FirstEnergy, FES and each of the Utility Registrants reflect all normal recurring adjustments that, in the opinion of management, are necessary to fairly present results of operations for the interim periods. Certain prior year amounts have been reclassified to conform to the current year presentation. Unless otherwise indicated, defined terms used herein have the meanings set forth in the accompanying Glossary of Terms.

FirstEnergy and its subsidiaries consolidate all majority-owned subsidiaries over which they exercise control and, when applicable, entities for which they have a controlling financial interest. Intercompany transactions and balances are eliminated in consolidation. FirstEnergy consolidates a VIE when it is determined that it is the primary beneficiary (see Note 7, Variable Interest Entities). Investments in affiliates over which FirstEnergy and its subsidiaries have the ability to exercise significant influence, but with respect to which are not the primary beneficiary and do not exercise control, follow the equity method of accounting. Under the equity method, the interest in the entity is reported as an investment in the Consolidated Balance Sheets and the percentage share of the entity s earnings is reported in the Consolidated Statements of Income.

2. MERGER

Merger

On February 25, 2011, the merger between FirstEnergy and Allegheny closed. Pursuant to the terms of the Agreement and Plan of Merger among FirstEnergy, Element Merger Sub, Inc., a Maryland corporation and a wholly-owned subsidiary of FirstEnergy (Merger Sub), and AE, Merger Sub merged with and into AE, with AE continuing as the surviving corporation and becoming a wholly-owned subsidiary of FirstEnergy. As part of the merger, AE shareholders received 0.667 of a share of FirstEnergy common stock for each share of AE common stock outstanding as of the date the merger was completed, and all outstanding AE equity-based employee compensation awards were converted into FirstEnergy equity-based awards on the same basis.

The merger created a combined company with increased scale and scope and greater diversification in energy delivery, generation and transmission. The combined company is the largest U.S. diversified electric utility by customers and operates one of the largest unregulated power generation fleets in the United States with FirstEnergy s total current capacity of approximately 23,000 MW, which includes approximately 3,000 MW of regulated generation.

The total consideration in the merger was based on the closing price of a share of FirstEnergy common stock on February 24, 2011, the day prior to the date the merger was completed, and was calculated as follows (in millions, except per share data):

Shares of Allegheny common stock outstanding on February 24, 2011		170
Exchange ratio		0.667
Number of shares of FirstEnergy common stock issued		113
Closing price of FirstEnergy common stock on February 24, 2011	$	38.16
Fair value of shares issued by FirstEnergy	$	4,327
Fair value of replacement share-based compensation awards relating to pre-merger service		27
Total consideration transferred	$	4,354

The preliminary allocation of the total consideration transferred to the assets acquired and liabilities assumed includes adjustments for the fair value of coal contracts, energy supply contracts, emission allowances, unregulated property, plant and equipment, derivative instruments, goodwill, intangible assets, long-term debt and deferred income taxes. The preliminary allocation of the purchase price is as follows:

(In millions)		**Preliminary Purchase Price Allocation**
Current assets	$	1,509
Property, plant and equipment		9,656
Investments		138
Goodwill		952
Other noncurrent assets		1,262
Current liabilities		(714)
Noncurrent liabilities		(3,453)
Long-term debt and other long-term obligations		(4,996)
	$	4,354

Assumptions and estimates underlying the fair value adjustments are subject to change pending further review of the assets acquired and liabilities assumed.

The excess of the purchase price over the estimated fair values of the assets acquired and liabilities assumed was recognized as goodwill. The Allegheny delivery, transmission and generation businesses have been assigned to the Regulated Distribution, Regulated Independent Transmission and Competitive Energy Services segments, respectively. The preliminary estimate of goodwill from the merger of $952 million was assigned entirely to the Competitive Energy Services segment based on expected synergies from the merger. The goodwill is not deductible for tax purposes.

Total goodwill recognized by segment in FirstEnergy s Consolidated Balance Sheet is as follows:

(In millions)	**Regulated Distribution**	**Competitive Energy Services**	**Regulated Independent Transmission**	**Other/ Corporate**	**Consolidated**

Balance at December 31, 2010	$	5,551	$	24	$		$		$	5,575
Merger with Allegheny				952						952
Balance at March 31, 2011	$	5,551	$	976	$		$		$	6,527

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The preliminary valuation of the additional intangible assets and liabilities recorded as result of the merger is as follows:

(In millions)	Preliminary Valuation	Weighted Average Amortization Period
Above market contracts:		
Energy supply contracts	$ 189	10 years
NUG contracts	124	25 years
Coal supply contracts	525	8 years
	838	
Below market contracts:		
NUG contracts	143	13 years
Coal supply contracts	86	7 years
Transportation contract	35	8 years
	264	
	$ 574	

The fair value measurements of intangible assets and liabilities were primarily based on significant unobservable inputs and thus represent level 3 measurements as defined in accounting guidance for fair value measurements.

The fair value of Allegheny s energy, NUG and gas transportation contracts, both above-market and below-market, were estimated based on the present value of the above/below market cash flows attributable to the contracts based on the contract type, discounted by a current market interest rate consistent with the overall credit quality of the portfolio. The above/below market cash flows were estimated by comparing the expected cash flow based on existing contracted prices and expected volumes with the cash flows from estimated current market contract prices for the same expected volumes. The estimated current market contract prices were derived considering current market prices, such as the price of energy and transmission, miscellaneous fees and a normal profit margin. The weighted average amortization period was determined based on the expected volumes to be delivered over the life of the contract.

The fair value of coal supply contracts was determined in a similar manner based on the present value of the above/below market cash flows attributable to the contracts. The fair value of these contracts will be amortized based on expected deliveries under each contract.

Total intangible assets recorded on FirstEnergy s Consolidated Balance Sheet as of March 31, 2011 are as follows:

(In millions)	Intangible Assets
Purchase contract assets	
NUG	$ 241
OVEC	52
	293
Intangible assets	
Coal contracts	520

FES customer intangible assets		132
Energy contracts		130
		782
	$	1,075

Other intangible assets acquired in the Allegheny merger include land easements and software, having a fair value of $126 million, are included in Property, plant and equipment on FirstEnergy s Consolidated Balance Sheet as of March 31, 2011.

In connection with the merger, FirstEnergy recorded approximately $82 million ($68 million net of tax) and $14 million ($10 million net of tax) of merger transaction costs during the first quarter of 2011 and 2010, respectively. These costs are included in Other operating expenses in the Consolidated Statement of Income. Merger transaction costs recognized in the first quarter of 2011 include $56 million ($47 net of tax) of change in control and other benefit payments to AE executives.

FirstEnergy also recorded approximately $75 million in merger integration costs during the first quarter of 2011, including an inventory valuation adjustment. In connection with the merger, FirstEnergy reviewed its inventory levels as a result of combining the inventory of both companies. Following this review FirstEnergy management determined the combined inventory stock contained excess and duplicative items. FirstEnergy management also adopted a consistent excess and obsolete inventory practice for the combined entity. Application of the revised practice, in conjunction with those items identified as excess and duplicative, resulted in an inventory valuation adjustment of $67 million ($42 million net of tax).

The amounts of revenue and earnings of Allegheny since the merger date included in FirstEnergy s Consolidated Statement of Income for the quarter ended March 31, 2011 are as follows:

(In millions, except per share amounts)		**February 26 - March 31, 2011**
Total revenues	$	437
Net Income[1]		(46)
Basic Earnings Per Share	$	(0.13)
Diluted Earnings Per Share	$	(0.13)

(1) Includes Allegheny s after-tax merger costs of $52 million.

Pro Forma Financial Information

The following unaudited pro forma financial information reflects the consolidated results of operations of FirstEnergy as if the merger with Allegheny had taken place on January 1, 2010. The unaudited pro forma information has been calculated after applying FirstEnergy s accounting policies and adjusting Allegheny s results to reflect the depreciation and amortization that would have been charged assuming fair value adjustments to property, plant and equipment, debt and intangible assets had been applied on January 1, 2010, together with the consequential tax effects.

FirstEnergy and Allegheny both incurred non-recurring costs directly related to the merger that have been included in the pro forma earnings presented below. Approximately $83 million and $27 million of combined pre-tax transaction costs were incurred in the three months ended March 31, 2011 and March 31, 2010, respectively. In addition, in the three months ended March 31, 2011, $75 million of pre-tax merger integration costs and $24 million of charges from merger settlements approved by regulatory agencies have been recognized. Charges resulting from merger settlements are not expected to be material in future periods.

The unaudited pro forma financial information has been presented for illustrative purposes only and is not necessarily indicative of results of operations that would have been achieved had the pro forma events taken place on the dates indicated, or the future consolidated results of operations of the combined company.

(Pro forma amounts in millions, except per share amounts)	**Three Months Ended March 31**			
		2011		**2010**
Revenues	$	4,786	$	4,685
Net income attributable to FirstEnergy	$	137	$	255
Basic Earnings Per Share	$	0.33	$	0.61
Diluted Earnings Per Share	$	0.33	$	0.61

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3. EARNINGS PER SHARE

Basic earnings per share of common stock are computed using the weighted average of actual common shares outstanding during the relevant period as the denominator. The denominator for diluted earnings per share of common stock reflects the weighted average of common shares outstanding plus the potential additional common shares that would be issued if dilutive securities and other agreements to issue common stock were exercised. The following table reconciles basic and diluted earnings per share of common stock:

Reconciliation of Basic and Diluted Earnings per Share of Common Stock	Three Months Ended March 31 2011	2010
	(In millions, except per share amounts)	
Earnings available to FirstEnergy Corp.	$ 50	$ 155
Weighted average number of basic shares outstanding[1]	342	304
Assumed exercise of dilutive stock options and awards	1	2
Weighted average number of diluted shares outstanding[1]	343	306
Basic earnings per share of common stock	$ 0.15	$ 0.51
Diluted earnings per share of common stock	$ 0.15	$ 0.51

(1) Includes 113 million shares issued to AE stockholders for the period subsequent to the merger date. (See Note 2, Merger)

4. FAIR VALUE OF FINANCIAL INSTRUMENTS

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

All borrowings with initial maturities of less than one year are defined as short-term financial instruments under GAAP and are reported on the Consolidated Balance Sheets at cost, which approximates their fair market value, in the caption short-term borrowings. The following table provides the approximate fair value and related carrying amounts of long-term debt and other long-term obligations as of March 31, 2011 and December 31 2010:

	March 31, 2011		December 31, 2010	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	(In millions)			
FirstEnergy[1]	$ 18,743	$ 19,776	$ 13,928	$ 14,845
FES	4,099	4,227	4,279	4,403
OE	1,159	1,334	1,159	1,321
CEI	1,831	2,035	1,853	2,035
TE	600	666	600	653
JCP&L	1,802	1,980	1,810	1,962
Met-Ed	742	826	742	821
Penelec	1,120	1,190	1,120	1,189

(1) Includes debt assumed in the Allegheny merger (See Note 2) with a carrying value and a fair value as of March 31, 2011 of $4,995 million and $5,004 million, respectively.

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

(B) INVESTMENTS

All temporary cash investments purchased with an initial maturity of three months or less are reported as cash equivalents on the Consolidated Balance Sheets at cost, which approximates their fair market value. Investments other than cash and cash equivalents include held-to-maturity securities, available-for-sale securities and notes receivable.

FES and the Utilities periodically evaluate their investments for other-than-temporary impairment. They first consider their intent and ability to hold an equity investment until recovery and then consider, among other factors, the duration and the extent to which the security s fair value has been less than cost and the near-term financial prospects of the security issuer when evaluating an investment for impairment. For debt securities, FES and the Utilities consider their intent to hold the security, the likelihood that they will be required to sell the security before recovery of their cost basis, and the likelihood of recovery of the security s entire amortized cost basis.

Available-For-Sale Securities

FES and the Utilities hold debt and equity securities within their nuclear decommissioning trusts, nuclear fuel disposal trusts and NUG trusts. These trust investments are considered as available-for-sale at fair market value. FES and the Utilities have no securities held for trading purposes.

The following table summarizes the amortized cost basis, unrealized gains and losses and fair values of investments held in nuclear decommissioning trusts, nuclear fuel disposal trusts and NUG trusts as of March 31, 2011 and December 31, 2010:

	March 31, 2011(1)				December 31, 2010(2)			
	Cost Basis	Unrealized Gains	Unrealized Losses	Fair Value	Cost Basis	Unrealized Gains	Unrealized Losses	Fair Value
				(In millions)				
Debt securities								
FirstEnergy	$ 1,985	$ 32	$	$ 2,017	$ 1,699	$ 31	$	$ 1,730
FES	1,012	18		1,030	980	13		993
OE	124	1		125	123	1		124
TE	51			51	42			42
JCP&L	358	7		365	281	9		290
Met-Ed	240	4		244	127	4		131
Penelec	200	2		202	145	4		149
Equity securities								
FirstEnergy	$ 186	$ 7	$	$ 193	$ 268	$ 69	$	$ 337
FES	88	5		93				
TE	24	1		25				
JCP&L	21			21	80	17		97
Met-Ed	33	1		34	125	35		160
Penelec	20			20	63	16		79

(1) Excludes cash investments, receivables, payables, deferred taxes and accrued income: FirstEnergy $97 million; FES $37 million; OE $2 million; TE $1 million; JCP&L $12 million; Met-Ed $27 million and Penelec $18 million.

(2) Excludes cash investments, receivables, payables, deferred taxes and accrued income: FirstEnergy $193 million; FES $153 million; OE $3 million; TE $34 million; JCP&L $3 million; Met-Ed $(3) million and Penelec $4 million.

Proceeds from the sale of investments in available-for-sale securities, realized gains and losses on those sales net of adjustments recorded, and interest and dividend income for the three months ended March 31, 2011 and 2010 were as follows:

March 31, 2011	Sales Proceeds	Realized Gains	Realized Losses	Interest and Dividend Income
		(In millions)		
FirstEnergy	$ 970	$ 100	$ (29)	$ 24
FES	216	12	(15)	15
OE	8			1
TE	14	1	(1)	1
JCP&L	217	22	(4)	4
Met-Ed	336	43	(5)	2
Penelec	179	22	(4)	1

March 31, 2010	Sales Proceeds	Realized Gains	Realized Losses	Interest and Dividend Income
		(In millions)		
FirstEnergy	$ 733	$ 37	$ (51)	$ 22
FES	272	13	(24)	13
OE	2			1
TE	31	1	(1)	1
JCP&L	190	8	(8)	4
Met-Ed	144	9	(11)	2
Penelec	93	6	(7)	1

Unrealized gains applicable to the decommissioning trusts of FES, OE and TE are recognized in OCI because fluctuations in fair value will eventually impact earnings. The decommissioning trusts of JCP&L, Met-Ed and Penelec are subject to regulatory accounting. Net unrealized gains and losses are recorded as regulatory assets or liabilities because the difference between investments held in trust and the decommissioning liabilities will be recovered from or refunded to customers.

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

FirstEnergy recognized $3 million and $11 million of net realized losses for the three-month period ended March 31, 2011 and 2010, respectively, resulting from the sale of securities held in nuclear decommissioning trusts.

Held-To-Maturity Securities

The following table provides the amortized cost basis, unrealized gains and losses, and approximate fair values of investments in held-to-maturity securities as of March 31, 2011 and December 31, 2010:

	March 31, 2011				December 31, 2010			
	Cost Basis	Unrealized Gains	Unrealized Losses	Fair Value	Cost Basis	Unrealized Gains	Unrealized Losses	Fair Value
				(In millions)				
Debt Securities								
FirstEnergy	$ 422	$ 79	$	$ 501	$ 476	$ 91	$	$ 567
OE	190	45		235	190	51		241

CEI	287	33	320	340	41	381

Investments in emission allowances, employee benefits and cost and equity method investments totaling $345 million as of March 31, 2011 and $259 million as of December 31, 2010 are not required to be disclosed and are excluded from the amounts reported above.

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Notes Receivable

The table below provides the approximate fair value and related carrying amounts of notes receivable as of March 31, 2011 and December 31, 2010. The fair value of notes receivable represents the present value of the cash inflows based on the yield to maturity. The yields assumed were based on financial instruments with similar characteristics and terms. The maturity dates range from 2013 to 2021.

	March 31, 2011		December 31, 2010	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	(In millions)			
Notes Receivable				
FirstEnergy	$ 7	$ 8	$ 7	$ 8
TE	82	94	104	118

(C) RECURRING FAIR VALUE MEASUREMENTS

Fair value is the price that would be received for an asset or paid to transfer a liability (exit price) in the principal or most advantageous market for the asset or liability in an orderly transaction between willing market participants on the measurement date. A fair value hierarchy has been established that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted market prices in active markets for identical assets or liabilities (Level 1) and the lowest priority to unobservable inputs (Level 3). The three levels of the fair value hierarchy are as follows:

Level 1 Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2 Pricing inputs are either directly or indirectly observable in the market as of the reporting date, other than quoted prices in active markets included in Level 1. Additionally, Level 2 includes those financial instruments that are valued using models or other valuation methodologies based on assumptions that are observable in the marketplace throughout the full term of the instrument and can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace. These models are primarily industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors, and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Instruments in this category may include non-exchange-traded derivatives such as forwards and certain interest rate swaps.

Level 3 Pricing inputs include inputs that are generally less observable from objective sources. These inputs may be used with internally developed methodologies that result in management s best estimate of fair value. FirstEnergy develops its view of the future market price of key commodities through a combination of market observation and assessment (generally for the short term) and fundamental modeling (generally for the long term). Key fundamental electricity model inputs are generally directly observable in the market or derived from publicly available historic and forecast data. Some key inputs reflect forecasts published by industry leading consultants who generally employ similar fundamental modeling approaches. Fundamental model inputs and results, as well as the selection of consultants, reflect the consensus of appropriate FirstEnergy management. Level 3 instruments include those that may be more structured or otherwise tailored to customers needs.

FirstEnergy utilizes market data and assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated, or generally unobservable. FirstEnergy primarily applies the market approach for recurring fair value measurements using the best information available. Accordingly, FirstEnergy maximizes the use of observable inputs and minimizes the use of unobservable inputs.

The determination of the fair value measures takes into consideration various factors. These factors include nonperformance risk, including counterparty credit risk and the impact of credit enhancements (such as cash deposits, LOCs and priority interests). The impact of nonperformance risk was immaterial in the fair value measurements.

The following tables set forth financial assets and liabilities that are accounted for at fair value by level within the fair value hierarchy as of March 31, 2011 and December 31, 2010. Assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. FirstEnergy s assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the fair valuation of assets and liabilities and their placement within the fair value hierarchy levels. The fair value of financial assets and liabilities as of March 31, 2011 assumed in the merger with Allegheny totaled $52 million and $51 million, respectively. There were no significant transfers between Level 1, Level 2 and Level 3 as of March 31, 2011 and December 31, 2010.

FirstEnergy Corp.

The following tables summarize assets and liabilities recorded on FirstEnergy s Consolidated Balance Sheets at fair value as of March 31, 2011 and December 31, 2010:

March 31, 2011		**Level 1**		**Level 2**		**Level 3**		**Total**
				(In millions)				
Assets								
Corporate debt securities	$		$	877	$		$	877
Derivative assets commodity contracts				524				524
Derivative assets FTRs						1		1
Derivative assets interest rate swaps				4				4
Derivative assets NUG contracts(1)						117		117
Equity securities(2)		194						194
Foreign government debt securities				150				150
U.S. government debt securities				681				681
U.S. state debt securities				297				297
Other(4)				148				148
Total assets	$	194	$	2,681	$	118	$	2,993
Liabilities								
Derivative liabilities commodity contracts	$		$	(583)	$		$	(583)
Derivative liabilities FTRs						(12)		(12)
Derivative liabilities interest rate swaps				(5)				(5)
Derivative liabilities NUG contracts(1)						(478)		(478)
Total liabilities	$		$	(588)	$	(490)	$	(1,078)
Net assets (liabilities)(3)	$	194	$	2,093	$	(372)	$	1,915

December 31, 2010		**Level 1**		**Level 2**		**Level 3**		**Total**
				(In millions)				
Assets								
Corporate debt securities	$		$	597	$		$	597
Derivative assets commodity contracts				250				250
Derivative assets NUG contracts(1)						122		122
Equity securities(2)		338						338
Foreign government debt securities				149				149
U.S. government debt securities				595				595
U.S. state debt securities				379				379
Other(4)				219				219
Total assets	$	338	$	2,189	$	122	$	2,649

Liabilities									
Derivative liabilities	commodity contracts	$		$	(348)	$		$	(348)
Derivative liabilities	NUG contracts[1]						(466)		(466)
Total liabilities		$		$	(348)	$	(466)	$	(814)
Net assets (liabilities)[3]		$	338	$	1,841	$	(344)	$	1,835

(1) NUG contracts are subject to regulatory accounting and do not impact earnings.

(2) NDT funds hold equity portfolios the performance of which is benchmarked against the S&P 500 Index or Russell 3000 Index.

(3) Excludes $(31) million and $(7) million as of March 31, 2011 and December 31, 2010, respectively, of receivables, payables, deferred taxes and accrued income associated with the financial instruments reflected within the fair value table.

(4) Primarily consists of cash and cash equivalents.

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Rollforward of Level 3 Measurements

The following table provides a reconciliation of changes in the fair value of NUG contracts held by the Utilities and FTRs held by FirstEnergy and classified as Level 3 in the fair value hierarchy for the periods ending March 31, 2011 and December 31, 2010, respectively:

	Derivative Asset[1]	Derivative Liability[1]	Net[1]
		(In millions)	
January 1, 2011 Balance	$ 122	$ (466)	$ (344)
Realized gain (loss)			
Unrealized gain (loss)	(1)	(89)	(90)
Purchases			
Issuances			
Sales			
Settlements	(3)	77	74
Transfers in (out) of Level 3		(12)	(12)
March 31, 2011 Balance	$ 118	$ (490)	$ (372)
January 1, 2010 Balance	$ 200	$ (643)	$ (443)
Realized gain (loss)			
Unrealized gain (loss)	(71)	(110)	(181)
Purchases			
Issuances			
Sales			
Settlements	(7)	287	280
Transfers in (out) of Level 3			
December 31, 2010 Balance	$ 122	$ (466)	$ (344)

(1) Changes in the fair value of NUG contracts are subject to regulatory accounting and do not impact earnings.

FirstEnergy Solutions Corp.

The following tables summarize assets and liabilities recorded on FES Consolidated Balance Sheets at fair value as of March 31, 2011 and December 31, 2010:

March 31, 2011	**Level 1**	**Level 2**	**Level 3**	**Total**
		(In millions)		
Assets				
Corporate debt securities	$	$ 567	$	$ 567
Derivative assets commodity contracts		476		476
Derivative assets FTRs			1	1
Equity securities[3]	93			93
Foreign government debt securities		148		148
U.S. government debt securities		304		304
U.S. state debt securities		8		8
Other[2]		43		43

Total assets	$	93	$	1,546	$	1	$	1,640
Liabilities								
Derivative liabilities commodity contracts	$		$	(549)	$		$	(549)
Total liabilities	$		$	(549)	$		$	(549)
Net assets (liabilities)[1]	$	93	$	997	$	1	$	1,091

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December 31, 2010	Level 1	Level 2	Level 3	Total
		(In millions)		
Assets				
Corporate debt securities	$	$ 528	$	$ 528
Derivative assets commodity contracts		241		241
Foreign government debt securities		147		147
U.S. government debt securities		308		308
U.S. state debt securities		6		6
Other[2]		148		148
Total assets	$	$ 1,378	$	$ 1,378
Liabilities				
Derivative liabilities commodity contracts	$	$ (348)	$	$ (348)
Total liabilities	$	$ (348)	$	$ (348)
Net assets (liabilities)[1]	$	$ 1,030	$	$ 1,030

(1) Excludes $(3) million and $7 million as of March 31, 2011 and December 31, 2010, respectively, of receivables, payables, deferred taxes and accrued income associated with the financial instruments reflected within the fair value table.

(2) Primarily consists of cash and cash equivalents.

(3) NDT funds hold equity portfolios the performance of which is benchmarked against the S&P 500 Index or Russell 3000 Index.

Rollforward of Level 3 Measurements

The following table provides a reconciliation of changes in the fair value of FTRs held by FES and classified as Level 3 in the fair value hierarchy for the period ending March 31, 2011:

	Derivative Asset FTRs	Derivative Liability FTRs	Net FTRs
		(In millions)	
January 1, 2011 Balance	$	$	$
Realized gain (loss)			
Unrealized gain (loss)	1		1
Purchases			
Issuances			
Sales			
Settlements			
Transfers in (out) of Level 3			
March 31, 2011 Balance	$ 1	$	$ 1

Ohio Edison Company

The following tables summarize assets and liabilities recorded on OE s Consolidated Balance Sheets at fair value as of March 31, 2011 and December 31, 2010:

March 31, 2011	**Level 1**	**Level 2**	**Level 3**	**Total**
		(In millions)		
Assets				
U.S. government debt securities	$	$ 125	$	$ 125
Other		6		6
Total assets(1)	$	$ 131	$	$ 131

December 31, 2010	**Level 1**	**Level 2**	**Level 3**	**Total**
		(In millions)		
Assets				
U.S. government debt securities	$	$ 124	$	$ 124
Other		2		2
Total assets(1)	$	$ 126	$	$ 126

(1) Excludes $(3) million and $1 million as of March 31, 2011 and December 31, 2010 of receivables, payables, deferred taxes and accrued income associated with the financial instruments reflected within the fair value table.

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Toledo Edison Company

The following tables summarize assets and liabilities recorded on TE s Consolidated Balance Sheets at fair value as of March 31, 2011 and December 31, 2010:

March 31, 2011	Level 1	Level 2	Level 3	Total
		(In millions)		
Assets				
Corporate debt securities	$	$ 16	$	$ 16
Equity securities[3]	25			25
U.S. government debt securities		32		32
U.S. state debt securities		2		2
Other[2]		3		3
Total assets[1]	$ 25	$ 53	$	$ 78

December 31, 2010	Level 1	Level 2	Level 3	Total
		(In millions)		
Assets				
Corporate debt securities	$	$ 7	$	$ 7
U.S. government debt securities		33		33
U.S. state debt securities		1		1
Other[2]		35		35
Total assets[1]	$	$ 76	$	$ 76

(1) Excludes $(1) million and $2 million as of March 31, 2011 and December 31, 2010 of receivables, payables, deferred taxes and accrued income associated with the financial instruments reflected within the fair value table.

(2) Primarily consists of cash and cash equivalents.

(3) NDT funds hold equity portfolios the performance of which is benchmarked against the S&P 500 Index or Russell 3000 Index.

Jersey Central Power & Light Company

The following tables summarize assets and liabilities recorded on JCP&L s Consolidated Balance Sheets at fair value as of March 31, 2011 and December 31, 2010:

March 31, 2011	Level 1	Level 2	Level 3	Total
		(In millions)		
Assets				
Corporate debt securities	$	$ 92	$	$ 92
Derivative assets commodity contracts				
Derivative assets NUG contracts[1]			6	6
Equity securities[2]	21			21
Foreign government debt securities		1		1
U.S. government debt securities		60		60
U.S. state debt securities		214		214
Other		16		16

Total assets	$	21	$	383	$	6	$	410
Liabilities								
Derivative liabilities NUG contracts[1]	$		$		$	(239)	$	(239)
Total liabilities	$		$		$	(239)	$	(239)
Net assets (liabilities)[3]	$	21	$	383	$	(233)	$	171

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December 31, 2010	Level 1	Level 2	Level 3	Total
		(In millions)		
Assets				
Corporate debt securities	$	$ 23	$	$ 23
Derivative assets commodity contracts		2		2
Derivative assets NUG contracts(1)			6	6
Equity securities(2)	96			96
U.S. government debt securities		33		33
U.S. state debt securities		236		236
Other		4		4
Total assets	$ 96	$ 298	$ 6	$ 400
Liabilities				
Derivative liabilities NUG contracts(1)	$	$	$ (233)	$ (233)
Total liabilities	$	$	$ (233)	$ (233)
Net assets (liabilities)(3)	$ 96	$ 298	$ (227)	$ 167

(1) NUG contracts are subject to regulatory accounting and do not impact earnings.

(2) NDT funds hold equity portfolios the performance of which is benchmarked against the S&P 500 Index or Russell 3000 Index.

(3) Excludes $(8) million and $(3) million as of March 31, 2011 and December 31, 2010 of receivables, payables, deferred taxes and accrued income associated with the financial instruments reflected within the fair value table.

Rollforward of Level 3 Measurements

The following table provides a reconciliation of changes in the fair value of NUG contracts held by JCP&L and classified as Level 3 in the fair value hierarchy for the periods ending March 31, 2011 and December 31, 2010:

	Derivative Asset NUG Contracts(1)	Derivative Liability NUG Contracts(1)	Net NUG Contracts(1)
		(In millions)	
January 1, 2011 Balance	$ 6	$ (233)	$ (227)
Realized gain (loss)			
Unrealized gain (loss)		(42)	(42)
Purchases			
Issuances			
Sales			
Settlements		36	36
Transfers in (out) of Level 3			
March 31, 2011 Balance	$ 6	$ (239)	$ (233)

January 1, 2010 Balance	$	8	$	(399)	$	(391)
Realized gain (loss)						
Unrealized gain (loss)		(1)		36		35
Purchases						
Issuances						
Sales						
Settlements		(1)		130		129
Transfers in (out) of Level 3						
December 31, 2010 Balance	$	6	$	(233)	$	(227)

(1) Changes in the fair value of NUG contracts are subject to regulatory accounting and do not impact earnings.

Metropolitan Edison Company

The following tables summarize assets and liabilities recorded on Met-Ed s Consolidated Balance Sheets at fair value as of March 31, 2011 and December 31, 2010:

March 31, 2011	Level 1	Level 2	Level 3	Total
		(In millions)		
Assets				
Corporate debt securities	$	$ 131	$	$ 131
Derivative assets commodity contracts				
Derivative assets NUG contracts(1)			107	107
Equity securities(2)	34			34
Foreign government debt securities		2		2
U.S. government debt securities		100		100
U.S. state debt securities		2		2
Other		37		37
Total assets	$ 34	$ 272	$ 107	$ 413
Liabilities				
Derivative liabilities NUG contracts(1)	$	$	$ (118)	$ (118)
Total liabilities	$	$	$ (118)	$ (118)
Net assets (liabilities)(3)	$ 34	$ 272	$ (11)	$ 295

December 31, 2010	Level 1	Level 2	Level 3	Total
		(In millions)		
Assets				
Corporate debt securities	$	$ 32	$	$ 32
Derivative assets commodity contracts		5		5
Derivative assets NUG contracts(1)			112	112
Equity securities(2)	160			160
Foreign government debt securities		1		1
U.S. government debt securities		88		88
U.S. state debt securities		2		2
Other		14		14
Total assets	$ 160	$ 142	$ 112	$ 414
Liabilities				
Derivative liabilities NUG contracts(1)	$	$	$ (116)	$ (116)
Total liabilities	$	$	$ (116)	$ (116)

Net assets (liabilities)[3]	$	160	$	142	$	(4)	$	298

(1) NUG contracts are subject to regulatory accounting and do not impact earnings.

(2) NDT funds hold equity portfolios the performance of which is benchmarked against the S&P 500 Index or Russell 3000 Index.

(3) Excludes $(1) million and $(9) million as of March 31, 2011 and December 31, 2010, respectively, of receivables, payables, deferred taxes and accrued income associated with the financial instruments reflected within the fair value table.

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Rollforward of Level 3 Measurements

The following table provides a reconciliation of changes in the fair value of NUG contracts held by Met-Ed and classified as Level 3 in the fair value hierarchy for the periods ending March 31, 2011 and December 31, 2010:

	Derivative Asset NUG Contracts[1]	Derivative Liability NUG Contracts[1]	Net NUG Contracts[1]
		(In millions)	
January 1, 2011 Balance	$ 112	$ (116)	$ (4)
Realized gain (loss)			
Unrealized gain (loss)	(2)	(16)	(18)
Purchases			
Issuances			
Sales			
Settlements	(3)	14	11
Transfers in (out) of Level 3			
March 31, 2011 Balance	$ 107	$ (118)	$ (11)
January 1, 2010 Balance	$ 176	$ (143)	$ 33
Realized gain (loss)			
Unrealized gain (loss)	(59)	(38)	(97)
Purchases			
Issuances			
Sales			
Settlements	(5)	65	60
Transfers in (out) of Level 3			
December 31, 2010 Balance	$ 112	$ (116)	$ (4)

(1) Changes in the fair value of NUG contracts are subject to regulatory accounting and do not impact earnings.

Pennsylvania Electric Company

The following tables summarize assets and liabilities recorded on Penelec s Consolidated Balance Sheets at fair value as of March 31, 2011 and December 31, 2010:

March 31, 2011	Level 1	Level 2	Level 3	Total
		(In millions)		
Assets				
Corporate debt securities	$	$ 70	$	$ 70
Derivative assets commodity contracts				
Derivative assets NUG contracts[1]			4	4
Equity securities[2]	20			20
Foreign government debt securities				
U.S. government debt securities		60		60
U.S. state debt securities		72		72
Other		32		32

Total assets	$	20	$	234	$	4	$	258
Liabilities								
Derivative liabilities NUG contracts[1]	$		$		$	(122)	$	(122)
Total liabilities	$		$		$	(122)	$	(122)
Net assets (liabilities)[3]	$	20	$	234	$	(118)	$	136

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December 31, 2010	Level 1	Level 2	Level 3	Total
		(In millions)		
Assets				
Corporate debt securities	$	$ 8	$	$ 8
Derivative assets commodity contracts		2		2
Derivative assets NUG contracts[1]			4	4
Equity securities[2]	81			81
U.S. government debt securities		9		9
U.S. state debt securities		133		133
Other		5		5
Total assets	$ 81	$ 157	$ 4	$ 242
Liabilities				
Derivative liabilities NUG contracts[1]	$	$	$ (117)	$ (117)
Total liabilities	$	$	$ (117)	$ (117)
Net assets (liabilities)[3]	$ 81	$ 157	$ (113)	$ 125

(1) NUG contracts are subject to regulatory accounting and do not impact earnings.

(2) NDT funds hold equity portfolios the performance of which is benchmarked against the S&P 500 Index or Russell 3000 Index.

(3) Excludes $(15) million and $(3) million as of March 31, 2011 and December 31, 2010, respectively, of receivables, payables and accrued income associated with the financial instruments reflected within the fair value table.

Rollforward of Level 3 Measurements

The following table provides a reconciliation of changes in the fair value of NUG and commodity contracts held by Penelec and classified as Level 3 in the fair value hierarchy for the periods ended March 31, 2011 and December 31, 2010:

	Derivative Asset NUG Contracts[1]	Derivative Liability NUG Contracts[1]	Net NUG Contracts[1]
		(In millions)	
January 1, 2011 Balance	$ 4	$ (117)	$ (113)
Realized gain (loss)			
Unrealized gain (loss)		(30)	(30)
Purchases			
Issuances			
Sales			
Settlements		25	25
Transfers in (out) of Level 3			

March 31, 2011 Balance	$	4	$	(122)	$	(118)
January 1, 2010 Balance	$	16	$	(101)	$	(85)
Realized gain (loss)						
Unrealized gain (loss)		(11)		(108)		(119)
Purchases						
Issuances						
Sales						
Settlements		(1)		92		91
Transfers in (out) of Level 3						
December 31, 2010 Balance	$	4	$	(117)	$	(113)

(1) Changes in the fair value of NUG contracts are subject to regulatory accounting and do not impact earnings.

5. DERIVATIVE INSTRUMENTS

FirstEnergy is exposed to financial risks resulting from fluctuating interest rates and commodity prices, including prices for electricity, natural gas, coal and energy transmission. To manage the volatility relating to these exposures, FirstEnergy established a Risk Policy Committee, comprised of members of senior management, which provides general management oversight for risk management activities throughout FirstEnergy. The Committee is responsible for promoting the effective design and implementation of sound risk management programs and oversees compliance with corporate risk management policies and established risk management practice. FirstEnergy also uses a variety of derivative instruments for risk management purposes including forward contracts, options, futures contracts and swaps. In addition to derivatives, FirstEnergy also enters into master netting agreements with certain third parties.

FirstEnergy accounts for derivative instruments on its Consolidated Balance Sheets at fair value unless they meet the normal purchases and normal sales criteria. Derivatives that meet those criteria are accounted for under the accrual method of accounting, and their effects are included in earnings at the time of contract performance. Changes in the fair value of derivative instruments that qualify and are designated as cash flow hedge instruments are recorded to AOCL. Change in the fair value of derivative instruments that are not designated as cash flow hedge instruments are recorded in the income statement on a mark-to-market basis. FirstEnergy s has contractual derivative agreements through December 2018.

Cash Flow Hedges

FirstEnergy has used cash flow hedges for risk management purposes to manage the volatility related to exposures associated with fluctuating interest rates and commodity prices. The effective portion of gains and losses on the derivative contract are reported as a component of AOCL with subsequent reclassification to earnings in the period during which the hedged forecasted transaction affects earnings.

As of December 31, 2010, commodity derivative contracts designated in cash flow hedging relationships were $104 million of assets and $101 million of liabilities. In February 2011, FirstEnergy elected to dedesignate all outstanding cash flow hedge relationships. Total net unamortized losses included in AOCL associated with dedesignated cash flow hedges totaled $6 million as of March 31, 2011. Since the forecasted transactions remain probable of occurring, these amounts were frozen in AOCL and will be amortized into earnings over the life of the hedging instruments. Reclassifications from AOCL into other operating expense totaled $5 million for the three-months ended March 31, 2011. Approximately $16 million will be amortized to earnings as expense during the next twelve months.

FirstEnergy has used forward starting swap agreements to hedge a portion of the consolidated interest rate risk associated with anticipated issuances of fixed-rate, long-term debt securities of its subsidiaries. These derivatives were treated as cash flow hedges, protecting against the risk of changes in future interest payments resulting from changes in benchmark U.S. Treasury rates between the date of hedge inception and the date of the debt issuance. As of March 31, 2011, no forward starting swap agreements were outstanding. Total unamortized losses included in AOCL associated with prior interest rate cash flow hedges totaled $87 million ($57 million net of tax) as of March 31, 2011. Based on current estimates, approximately $10 million will be amortized to interest expense during the next twelve months. Reclassifications from AOCL into interest expense totaled $3 million for the three-months ended March 31, 2011 and 2010.

Fair Value Hedges

FirstEnergy has used fixed-for-floating interest rate swap agreements to hedge a portion of the consolidated interest rate risk associated with the debt portfolio of its subsidiaries. These derivative instruments were 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. As of March 31, 2011, no fixed-for-floating interest rate swap agreements were outstanding.

As of March 31, 2010, FirstEnergy held fixed-for-floating interest rate swap agreements with combined notional amounts of $950 million. The gains included in interest expense related to interest rate swaps totaled $1 million and the fair value of the derivative instruments totaled $(3) million. There was no impact on the results of operations as a result of ineffectiveness from fair value hedges.

Total unamortized gains included in long-term debt associated with prior fixed-for-floating interest rate swap agreements totaled $118 million ($77 million net of tax) as of March 31, 2011. Based on current estimates, approximately $22 million will be amortized to interest expense during the next twelve months. Reclassifications from long-term debt into interest expense totaled approximately $5 million and $1 million for the three-months ended March 31, 2011 and 2010, respectively.

Commodity Derivatives

FirstEnergy uses both physically and financially settled derivatives to manage its exposure to volatility in commodity prices. Commodity derivatives are used for risk management purposes to hedge exposures when it makes economic sense to do so, including circumstances where the hedging relationship does not qualify for hedge accounting.

Electricity forwards are used to balance expected sales with expected generation and purchased power. Natural gas futures are entered into based on expected consumption of natural gas, primarily natural gas used in FirstEnergy s peaking units. Heating oil futures are entered into based on expected consumption of oil and the financial risk in FirstEnergy s coal transportation contracts. Interest rate swaps include two interest rate swap agreements that expire during 2011 with an aggregate notional value of $200 million that were entered into during 2003 to substantially offset two existing interest rate swaps with the same counterparty. The 2003 agreements effectively locked in a net liability and substantially eliminated future income volatility from the interest rate swap positions but do not qualify for cash flow hedge accounting. Derivative instruments are not used in quantities greater than forecasted needs.

As of March 31, 2011, FirstEnergy s net liability position under commodity derivative contracts was $59 million, which primarily related to FES positions. Under these commodity derivative contracts, FES posted $120 million and Allegheny posted $1 million in collateral. Certain commodity derivative contracts include credit risk related contingent features that would require FES to post $24 million of additional collateral if the credit rating for its debt were to fall below investment grade.

Based on derivative contracts held as of March 31, 2011, an adverse 10% change in commodity prices would decrease net income by approximately $12 million ($7 million net of tax) during the next twelve months.

FTRs

FirstEnergy holds FTRs that generally represent an economic hedge of future congestion charges that will be incurred in connection with FirstEnergy s load obligations. These future obligations are reflected on the Consolidated Balance Sheets; and have not been designated as cash flow hedge instruments. FirstEnergy acquires the majority of its FTRs in an annual auction through a self-scheduling process involving the use of auction revenue rights allocated to members of an RTO that have load serving obligations. FirstEnergy initially records FTRs at the FTR auction price less the obligation due to the RTO, and subsequently adjusts the carrying value of remaining FTRs to their estimated fair value at the end of each accounting period prior to settlement. Changes in the fair value of FTRs held by FirstEnergy s unregulated subsidiaries are included in other operating expenses as unrealized gains or losses. Unrealized gains or losses on FTRs held by FirstEnergy s regulated subsidiaries are recorded as regulatory assets or liabilities.

The following tables summarize the fair value of derivative instruments in FirstEnergy s Consolidated Balance Sheets:

Derivatives not designated as hedging instruments as of March 31, 2011:

Derivative Assets

	Fair Value	
	March 31, 2011	**December 31, 2010**
	(In millions)	
Power Contracts		
Current Assets	$ 332	$ 151
Noncurrent Assets	192	89
FTRs		
Current Assets	1	
Noncurrent Assets		
NUGs		
Current Assets	3	3
Noncurrent Assets	114	119
Interest Rate Swaps		
Current Assets	4	
Noncurrent Assets		
Other		
Current Assets		10
Noncurrent Assets		

Total Derivatives	$	646	$	372

Derivative Liabilities

	Fair Value			
	March 31, 2011		December 31, 2010	
	(In millions)			
Power Contracts				
Current Liabilities	$	408	$	266
Noncurrent Liabilities		175		81
FTRs				
Current Liabilities		12		
Noncurrent Liabilities				
NUGs				
Current Liabilities		277		229
Noncurrent Liabilities		202		238
Interest Rate Swaps				
Current Liabilities		5		
Noncurrent Liabilities				
Other				
Current Liabilities				
Noncurrent Liabilities				
Total Derivatives	$	1,079	$	814

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The following table summarizes the volume of FirstEnergy s outstanding derivative transactions as of March 31, 2011:

	Purchases	Sales	Net	Units
		(In thousands)		
Power Contracts	83,603	(100,407)	(16,804)	MWH
FTRs	18,199	(130)	18,069	MWH
Interest Rate Swaps	200,000	(200,000)		notional dollars
NUGs	29,824		29,824	MWH

The effect of derivative instruments on the consolidated statements of income for the three months ended March 31, 2011 and 2010, are summarized in the following tables:

	Three Months Ended March 31,				
	Power Contracts	FTRs	Interest Rate Swaps	Other	Total
			(In millions)		
Derivatives in a Hedging Relationship					
2011					
Gain (Loss) Recognized in AOCL (Effective Portion)	$ (9)	$	$		$ (9)
Effective Gain (Loss) Reclassified to: (1)					
Purchase Power Expense	14				14
Wholesale Revenue	(3)				(3)
2010					
Gain (Loss) Recognized in AOCL (Effective Portion)	$ (2)			3	$ 1
Effective Gain (Loss) Reclassified to:(1)					
Purchase Power Expense	2				2
Fuel Expense				4	4
Derivatives Not in a Hedging Relationship					
2011					
Unrealized Gain (Loss) Recognized in:					
Purchase Power Expense	$ 29				$ 29
Wholesale Revenue					
Other Operating Expense	(20)	1			(19)
Realized Gain (Loss) Reclassified to:					
Purchase Power Expense	(19)	(2)			(21)
Wholesale Revenue	(2)		(1)		(3)
2010					
Unrealized Gain (Loss) Recognized in:					
Purchase Power Expense	$ (27)				$ (27)
Realized Gain (Loss) Reclassified to:					
Purchase Power Expense	(25)				(25)

Derivatives Not in a Hedging Relationship with Regulatory Offset[2]	Three Months Ended March 31, NUGs	Other	Total
	(In millions)		
2011			
Unrealized Loss to NUG Liability:	$ (89)	$	$ (89)
Unrealized Gain to Regulatory Assets:	89		89
Realized Gain to NUG Liability:	72		72
Realized Loss to Regulatory Assets:	(72)		(72)
Realized Loss to Deferred Charges		(10)	(10)
Realized Gain to Regulatory Assets:		10	10
2010			
Unrealized Loss to NUG Liability:	$ (224)		$ (224)
Unrealized Gain to Regulatory Assets:	224		224
Realized Gain to NUG Liability:	78		78
Realized Loss to Regulatory Assets:	(78)		(78)
Realized Loss to Deferred Charges		(9)	(9)
Realized Gain to Regulatory Assets:		9	9

(1) The ineffective portion was immaterial.

(2) Changes in the fair value of certain contracts are deferred for future recovery from (or refund to) customers.

The following table provides a reconciliation of changes in the fair value of certain contracts that are deferred for future recover from (or refund to) customers.

Derivatives Not in a Hedging Relationship with Regulatory Offset[1]	Three Months Ended March 31, NUGs	Other	Total
	(In millions)		
Outstanding net asset (liability) as of January 1, 2011	$ (345)	$ 10	$ (335)
Additions/Change in value of existing contracts	(89)		(89)
Settled contracts	72	(10)	62
Outstanding net asset (liability) as of March 31, 2011	$ (362)	$	$ (362)
Outstanding net asset (liability) as of January 1, 2010	$ (444)	$ 19	$ (425)
Additions/Change in value of existing contracts	(224)		(224)
Settled contracts	78	(9)	69
Outstanding net asset (liability) as of March 31, 2010	$ (590)	$ 10	$ (580)

(1) Changes in the fair value of certain contracts are deferred for future recovery from (or refund to) customers.

6. PENSION AND OTHER POSTRETIREMENT BENEFITS

FirstEnergy provides noncontributory qualified defined benefit pension plans that cover substantially all of its employees and non-qualified pension plans that cover certain employees. The plans provide defined benefits based on

years of service and compensation levels.
FirstEnergy provides a portion of non-contributory pre-retirement basic life insurance for employees who are eligible to retire. Health care benefits, which include certain employee contributions, deductibles and co-payments, are also available upon retirement to certain employees, their dependents and, under certain circumstances, their survivors. FirstEnergy also has obligations to former or inactive employees after employment, but before retirement, for disability-related benefits.

FirstEnergy s funding policy is based on actuarial computations using the projected unit credit method. During the first quarter of 2011, FirstEnergy made a $157 million contribution to its qualified pension plans. FirstEnergy intends to make additional contributions of $220 million and $6 million to its qualified pension plans and postretirement benefit plans, respectively, in the last three quarters of 2011.

FirstEnergy measured the funded status of the Allegheny pension plans and postretirement benefit plans other than pensions as of the merger closing date using discount rates of 5.50% and 5.25%, respectively. As a result of the fair value measurement, FirstEnergy recorded accumulated benefit obligation reductions to the Allegheny pension plans and postretirement benefits other than pensions in the amount of $6 million and $2 million, respectively. The expected returns on plan assets used to calculate net period costs for the month ended March 31, 2011 was 8.25% for the Allegheny qualified pension plan and 5.00% for the Allegheny postretirement benefit plans other than pension plans. The fair values of plan assets for Allegheny s pension plans and postretirement benefit plans other than pensions at the date of the merger were $954 million and $75 million, respectively, and the actuarially determined benefit obligations for such plans at that date were $1,341 million and $272 million, respectively.

FirstEnergy s net pension and OPEB expenses for the three months ended March 31, 2011 and 2010 were $28 million and $24 million, respectively. The components of FirstEnergy s net pension and OPEB (including amounts capitalized) for the three months ended March 30, 2011 and 2010, consisted of the following:

	Three Months Ended March 31	
Pension Benefit Cost (Credit)	**2011**	**2010**
	(In millions)	
Service cost	$ 29	$ 25
Interest cost	84	78
Expected return on plan assets	(102)	(90)
Amortization of prior service cost	4	3
Recognized net actuarial loss	49	47
Curtailments [1]	(2)	
Special termination benefits [1]	9	
Net periodic cost	**$ 71**	**$ 63**

(1) Represents costs (credits) incurred related to change in control provision payments to certain executives who were terminated or were expected to be terminated as a result of the merger.

	Three Months Ended March 31	
Other Postretirement Benefit Cost (Credit)	**2011**	**2010**
	(In millions)	
Service cost	$ 3	$ 2
Interest cost	11	11
Expected return on plan assets	(10)	(9)
Amortization of prior service cost	(48)	(48)
Recognized net actuarial loss	14	15
Net periodic cost	**$ (30)**	**$ (29)**

Pension and other postretirement benefit obligations are allocated to FirstEnergy s subsidiaries employing the plan participants. The net periodic pension costs and net periodic other postretirement benefit costs (including amounts capitalized) recognized by FirstEnergy s subsidiaries for the three months ended March 31, 2011 and 2010 were as follows:

	Three Months Ended March 31	
Pension Benefit Cost (Credit)	**2011**	**2010**
	(In millions)	
FES	$ 22	$ 22
OE	5	6
CEI	5	5
TE	1	2
JCP&L	5	6
Met-Ed	3	2
Penelec	5	5
Other FirstEnergy Subsidiaries	25	15
	$ 71	**$ 63**

	Three Months Ended March 31	
Other Postretirement Benefit Cost (Credit)	**2011**	**2010**
	(In millions)	
FES	$ (6)	$ (7)
OE	(6)	(6)
CEI	(2)	(1)
TE		(1)
JCP&L	(2)	(2)
Met-Ed	(3)	(2)
Penelec	(3)	(2)
Other FirstEnergy Subsidiaries	(8)	(8)
	$ (30)	**$ (29)**

7. VARIABLE INTEREST ENTITIES

FirstEnergy and its subsidiaries perform qualitative analyses to determine whether a variable interest gives FirstEnergy or its subsidiaries a controlling financial interest in a VIE. This analysis identifies the primary beneficiary of a VIE as the enterprise that has both the power to direct the activities of a VIE that most significantly impact the entity s economic performance and the obligation to absorb losses of the entity that could potentially be significant to the VIE or the right to receive benefits from the entity that could potentially be significant to the VIE.

VIE s included in FirstEnergy s consolidated financial statements are: FEV s joint venture in the Signal Peak mining and coal transportation operations; the PNBV and Shippingport bond trusts that were created to refinance debt originally issued in connection with sale and leaseback transactions; and wholly owned limited liability companies of JCP&L created to sell transition bonds to securitize the recovery of JCP&L s bondable stranded costs associated with the previously divested Oyster Creek Nuclear Generating Station, of which $302 million was outstanding as of March 31, 2011.

FirstEnergy and its subsidiaries reflect the portion of VIEs not owned by them in the caption noncontrolling interest within the consolidated financial statements. The change in noncontrolling interest within the consolidated balance sheets is the result of net losses of the noncontrolling interests ($5 million) and distributions to owners ($3 million) for the three months ended March 31, 2011.

In order to evaluate contracts for consolidation treatment and entities for which FirstEnergy has an interest, FirstEnergy aggregated variable interests into the following categories based on similar risk characteristics and significance as follows:

PATH-WV

PATH, LLC was formed to construct, through its operating companies, a portion of the PATH Project, which is a high-voltage transmission line that is proposed to extend from West Virginia through Virginia and into Maryland, including modifications to an existing substation in Putnam County, West Virginia, and the construction of new substations in Hardy County, West Virginia and Frederick County, Maryland as directed by PJM. PATH, LLC is a series limited liability company that is comprised of multiple series, each of which has separate rights, powers and duties regarding specified property and the series profits and losses associated with such property. A subsidiary of AE owns 100% of the Allegheny Series and 50% of the West Virginia Series (PATH-WV), which is a joint venture with a subsidiary of AEP. FirstEnergy is not the primary beneficiary of PATH-WV, as it does not have control over the significant activities affecting the economics of the portion of the PATH Project to be constructed by PATH-WV. Because of the nature of PATH-WV s operations and its FERC approved rate mechanism, FirstEnergy s maximum exposure to loss, through AE, consists of its equity investment in PATH-WV, which was $26 million at March 31, 2011.

Power Purchase Agreements

FirstEnergy evaluated its power purchase agreements and determined that certain NUG entities may be VIEs to the extent that they own a plant that sells substantially all of its output to the Utilities if the contract price for power is correlated with the plant s variable costs of production. FirstEnergy, through its subsidiaries JCP&L, Met-Ed, Penelec, PE, WP and MP, maintains 23 long-term power purchase agreements with NUG entities. The agreements were entered into pursuant to PURPA. FirstEnergy was not involved in the creation of, and has no equity or debt invested in, these entities.

FirstEnergy has determined that for all but four of these NUG entities, its subsidiaries do not have variable interests in the entities or the entities do not meet the criteria to be considered a VIE. JCP&L, PE and WP may hold variable interests in the remaining four entities; however, FirstEnergy applied the scope exception that exempts enterprises unable to obtain the necessary information to evaluate entities.

Because JCP&L, PE and WP have no equity or debt interests in the NUG entities, their maximum exposure to loss relates primarily to the above-market costs incurred for power. FirstEnergy expects any above-market costs incurred by its subsidiaries to be recovered from customers. Purchased power costs related to the four contracts that may contain a variable interest that were held by FirstEnergy subsidiaries during the three months ended March 31, 2011, were $65 million, $11 million and $5 million for JCP&L, PE and WP, respectively. Purchased power costs related to the two contracts that may contain a variable interest that were held by JCP&L during the three months ended March 31, 2010 were $64 million.

In 1998 the PPUC issued an order approving a transition plan for WP that disallowed certain costs, including an estimated amount for an adverse power purchase commitment related to the NUG entity that WP may hold a variable interest, for which WP has taken the scope exception. As of March 31, 2011, WP s reserve for this adverse purchase power commitment was $61 million, including a current liability of $18 million, and is being amortized over the life of the commitment.

Loss Contingencies

FirstEnergy has variable interests in certain sale-leaseback transactions. FirstEnergy is not the primary beneficiary of these interests as it does not have control over the significant activities affecting the economics of the arrangement.

FES and the Ohio Companies are exposed to losses under their applicable sale-leaseback agreements upon the occurrence of certain contingent events. The maximum exposure under these provisions represents the net amount of casualty value payments due upon the occurrence of specified casualty events. Net discounted lease payments would not be payable if the casualty loss payments were made. The following table discloses each company s net exposure to loss based upon the casualty value provisions mentioned above as of March 31, 2011:

	Maximum Exposure	Discounted Lease Payments, net[1]	Net Exposure
		(In millions)	
FES	$ 1,376	$ 1,187	$ 189
OE	644	485	159
CEI[2]	664	68	596
TE[2]	664	351	313

(1) The net present value of FirstEnergy s consolidated sale and leaseback operating lease commitments is $1.7 billion.

(2) CEI and TE are jointly and severally liable for the maximum loss amounts under certain sale-leaseback agreements.

8. INCOME TAXES

FirstEnergy accounts for uncertainty in income taxes recognized in its financial statements. Accounting guidance prescribes a recognition threshold and measurement attribute for financial statement recognition and measurement of tax positions taken or expected to be taken on a company s tax return. As a result of the merger with Allegheny in the first quarter of 2011, FirstEnergy s unrecognized tax benefits increased by $97 million. There were no other material changes to FirstEnergy s unrecognized tax benefits during the first three months of 2011. After reaching a tentative agreement with the IRS on a tax item at appeals related to the capitalization of certain costs in the first quarter of 2010, FirstEnergy reduced the amount of unrecognized tax benefits by $57 million, with a corresponding adjustment to accumulated deferred income taxes for this temporary tax item. There was no impact on FirstEnergy s effective tax rate for this tax item in the first three months of 2010.

As of March 31, 2011, it is reasonably possible that approximately $48 million of unrecognized benefits may be resolved within the next twelve months, of which approximately $6 million, if recognized, would affect FirstEnergy s effective tax rate. The potential decrease in the amount of unrecognized tax benefits is primarily associated with issues related to the capitalization of certain costs and various state tax items.

FirstEnergy recognizes interest expense or income related to uncertain tax positions. That amount is computed by applying the applicable statutory interest rate to the difference between the tax position recognized and the amount previously taken or expected to be taken on the tax return. FirstEnergy includes net interest and penalties in the provision for income taxes. During the first three months of 2011, there were no material changes to the amount of accrued interest, except for a $6 million increase in accrued interest from Allegheny. The reversal of accrued interest associated with the $57 million in recognized tax benefits in 2010 favorably affected FirstEnergy s effective tax rate by $5 million in the first quarter of 2010. The net amount of interest accrued as of March 31, 2011 was $10 million, compared with $3 million as of December 31, 2010.

As a result of the non-deductible portion of merger transaction costs, FirstEnergy s effective tax rate was unfavorably impacted by $30 million in the first quarter of 2011.

As a result of the Patient Protection and Affordable Care Act and the Health Care and Education Affordability Reconciliation Act signed into law in March 2010, beginning in 2013 the tax deduction available to FirstEnergy will be reduced to the extent that drug costs are reimbursed under the Medicare Part D retiree subsidy program. As retiree healthcare liabilities and related tax impacts under prior law were already reflected in FirstEnergy s consolidated financial statements, the change resulted in a charge to FirstEnergy s earnings in the first quarter of 2010 of approximately $13 million and a reduction in accumulated deferred tax assets associated with these subsidies. That charge reflected the anticipated increase in income taxes that will occur as a result of the change in tax law.

Allegheny recorded as deferred income tax assets the effect of net operating losses and tax credits that will more likely than not be realized through future operations and through the reversal of existing temporary differences. The tax effected net operating loss carryforwards consisted of $152 million of state net operating loss carryforwards that expire from 2019 through 2029 and $53 million of federal net operating loss carryforwards that expire from 2023 to 2029. Federal Alternative Minimum Tax credits of $25 million have an indefinite carryforward period.

Allegheny is currently under audit by the IRS for tax years 2007 and 2008. The 2009 federal return was filed and is subject to review. State tax returns for tax years 2006 through 2009 remain subject to review in Pennsylvania, West Virginia, Maryland and Virginia for certain subsidiaries of AE. FirstEnergy has tax returns that are under review at the audit or appeals level by the IRS (2008-2010) and state tax authorities. Tax returns for all state jurisdictions are open from 2006-2009. The IRS began auditing the year 2008 in February 2008 and the audit was completed in July 2010 with one item under appeal. The 2009 tax year audit began in February 2009 and the 2010 tax year audit began in February 2010. Management believes that adequate reserves have been recognized and final settlement of these audits is not expected to have a material adverse effect on FirstEnergy s financial condition or results of operations.

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9. COMMITMENTS, GUARANTEES AND CONTINGENCIES

(A) GUARANTEES AND OTHER ASSURANCES

As part of normal business activities, FirstEnergy enters into various agreements on behalf of its subsidiaries to provide financial or performance assurances to third parties. These agreements include contract guarantees, surety bonds and LOCs. As of March 31, 2011, outstanding guarantees and other assurances aggregated approximately $3.8 billion, consisting primarily of parental guarantees ($0.8 billion), subsidiaries guarantees ($2.6 billion), surety bonds and LOCs ($0.4 billion).

FirstEnergy guarantees energy and energy-related payments of its subsidiaries involved in energy commodity activities principally to facilitate or hedge normal physical transactions involving electricity, gas, emission allowances and coal. FirstEnergy also provides guarantees to various providers of credit support for the financing or refinancing by subsidiaries of costs related to the acquisition of property, plant and equipment. These agreements legally obligate FirstEnergy to fulfill the obligations of those subsidiaries directly involved in energy and energy-related transactions or financing where the law might otherwise limit the counterparties claims. If demands of a counterparty were to exceed the ability of a subsidiary to satisfy existing obligations, FirstEnergy s guarantee enables the counterparty s legal claim to be satisfied by other FirstEnergy assets. FirstEnergy views as remote the likelihood that such parental guarantees of $0.2 billion (included in the $0.8 billion discussed above) as of March 31, 2011 would increase amounts otherwise payable by FirstEnergy to meet its obligations incurred in connection with financings and ongoing energy and energy-related activities.

While these types of guarantees are normally parental commitments for the future payment of subsidiary obligations, subsequent to the occurrence of a credit rating downgrade or material adverse event, the immediate posting of cash collateral, provision of an LOC or accelerated payments may be required of the subsidiary. As of March 31, 2011, FirstEnergy s maximum exposure under these collateral provisions was $557 million, consisting of $433 million due to a below investment grade credit rating (of which $184 million is due to an acceleration of payment or funding obligation) and $124 million due to material adverse event contractual clauses. Additionally, stress case conditions of a credit rating downgrade or material adverse event and hypothetical adverse price movements in the underlying commodity markets would increase this amount to $623 million, consisting of $494 million due to a below investment grade credit rating (of which $184 million is related to an acceleration of payment or funding obligation) and $129 million due to material adverse event contractual clauses.

Most of FirstEnergy s surety bonds are backed by various indemnities common within the insurance industry. Surety bonds and related guarantees of $138 million provide additional assurance to outside parties that contractual and statutory obligations will be met in a number of areas including construction contracts, environmental commitments and various retail transactions.

In addition to guarantees and surety bonds, contracts entered into by the Competitive Energy Services segment, including power contracts with affiliates awarded through competitive bidding processes, typically contain margining provisions that require the posting of cash or LOCs in amounts determined by future power price movements. Based on FES and AE Supply s power portfolio as of March 31, 2011 and forward prices as of that date, FES and AE Supply have posted collateral of $158 million and $5 million, respectively. Under a hypothetical adverse change in forward prices (95% confidence level change in forward prices over a one year time horizon), FES would be required to post an additional $52 million of collateral. Depending on the volume of forward contracts and future price movements, higher amounts for margining could be required to be posted.

In connection with FES obligations to post and maintain collateral under the two-year PSA entered into by FES and the Ohio Companies following the CBP auction on May 13-14, 2009, NGC entered into a Surplus Margin Guaranty in an amount up to $500 million. The Surplus Margin Guaranty is secured by an NGC FMB issued in favor of the Ohio Companies.

FES debt obligations are generally guaranteed by its subsidiaries, FGCO and NGC, and FES guarantees the debt obligations of each of FGCO and NGC. Accordingly, present and future holders of indebtedness of FES, FGCO and NGC will have claims against each of FES, FGCO and NGC, regardless of whether their primary obligor is FES, FGCO or NGC.

Signal Peak and Global Rail are borrowers under a $350 million syndicated two-year senior secured term loan facility. FirstEnergy, together with WMB Loan Ventures LLC and WMB Loan Ventures II LLC, the entities that share ownership in the borrowers with FEV, have provided a guaranty of the borrowers obligations under the facility. In addition, FEV and the other entities that directly own the equity interest in the borrowers have pledged those interests to the lenders under the term loan facility as collateral for the facility.

(B) ENVIRONMENTAL MATTERS

Various federal, state and local authorities regulate FirstEnergy with regard to air and water quality and other environmental matters. Compliance with environmental regulations could have a material adverse effect on FirstEnergy s earnings and competitive position to the extent that FirstEnergy 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.

CAA Compliance

FirstEnergy is required to meet federally-approved SO_2 and NOx emissions regulations under the CAA. FirstEnergy complies with SO_2 and NOx reduction requirements under the CAA and SIP(s) by burning lower-sulfur fuel, combustion controls and post-combustion controls, generating more electricity from lower-emitting plants and/or using emission allowances. Violations can result in the shutdown of the generating unit involved and/or civil or criminal penalties.

The Sammis, Eastlake and Mansfield coal-fired plants are operated under a consent decree with the EPA and DOJ that requires reductions of NOx and SO_2 emissions through the installation of pollution control devices or repowering. OE and Penn are subject to stipulated penalties for failure to install and operate such pollution controls in accordance with that agreement.

In July 2008, three complaints were filed against FGCO in the U.S. District Court for the Western District of Pennsylvania seeking damages based on Bruce Mansfield Plant air emissions. Two of these complaints also seek to enjoin the Bruce Mansfield Plant from operating except in a safe, responsible, prudent and proper manner one being a complaint filed on behalf of twenty-one individuals and the other being a class action complaint seeking certification as a class action with the eight named plaintiffs as the class representatives. FGCO believes the claims are without merit and intends to defend itself against the allegations made in these three complaints.

The states of New Jersey and Connecticut filed CAA citizen suits in 2007 alleging NSR violations at the Portland Generation Station against GenOn Energy, Inc. (formerly RRI Energy, Inc. and the current owner and operator), Sithe Energy (the purchaser of the Portland Station from Met-Ed in 1999) and Met-Ed. Specifically, these suits allege that modifications at Portland Units 1 and 2 occurred between 1980 and 2005 without preconstruction NSR permitting in violation of the CAA s PSD program, and seek injunctive relief, penalties, attorney fees and mitigation of the harm caused by excess emissions. In September 2009, the Court granted Met-Ed s motion to dismiss New Jersey s and Connecticut s claims for injunctive relief against Met-Ed, but denied Met-Ed s motion to dismiss the claims for civil penalties. The parties dispute the scope of Met-Ed s indemnity obligation to and from Sithe Energy, and Met-Ed is unable to predict the outcome of this matter.

In January 2009, the EPA issued a NOV to GenOn Energy, Inc. alleging NSR violations at the Portland Generation Station based on modifications dating back to 1986 and also alleged NSR violations at the Keystone and Shawville Stations based on modifications dating back to 1984. Met-Ed, JCP&L, as the former owner of 16.67% of the Keystone Station, and Penelec, as former owner and operator of the Shawville Station, are unable to predict the outcome of this matter.

In June 2008, the EPA issued a Notice and Finding of Violation to Mission Energy Westside, Inc. (Mission) alleging that modifications at the Homer City Power Station occurred from 1988 to the present without preconstruction NSR permitting in violation of the CAA s PSD program. In May 2010, the EPA issued a second NOV to Mission, Penelec, New York State Electric & Gas Corporation and others that have had an ownership interest in the Homer City Power Station containing in all material respects allegations identical to those included in the June 2008 NOV. On July 20, 2010, the states of New York and Pennsylvania provided Mission, Penelec, NYSEG and others that have had an ownership interest in the Homer City Power Station a notification that was required 60 days prior to filing a citizen suit under the CAA. In January 2011, the DOJ filed a complaint against Penelec in the U.S. District Court for the Western District of Pennsylvania seeking injunctive relief against Penelec based on alleged modifications at the Homer City Power Station between 1991 to 1994 without preconstruction NSR permitting in violation of the CAA s PSD and Title V permitting programs. The complaint was also filed against the former co-owner, New York State Electric and Gas Corporation, and various current owners of the Homer City Station, including EME Homer City Generation L.P. and affiliated companies, including Edison International. In January 2011, another complaint was filed against Penelec and the other entities described above in the U.S. District Court for the Western District of Pennsylvania seeking damages based on the Homer City Station s air emissions as well as certification as a class action and to enjoin the Homer City Station from operating except in a safe, responsible, prudent and proper manner. Penelec believes the claims are without merit and intends to defend itself against the allegations made in the complaint, but, at this time, is unable to predict the outcome of this matter. In addition, the Commonwealth of Pennsylvania and the States of New Jersey and New York intervened and have filed separate complaints regarding the Homer City Station seeking injunctive relief and civil penalties. Mission is seeking indemnification from Penelec, the co-owner and operator of the Homer City Power Station prior to its sale in 1999. The scope of Penelec s indemnity obligation to and from Mission is under dispute and Penelec is unable to predict the outcome of this matter.

In August 2009, the EPA issued a Finding of Violation and NOV alleging violations of the CAA and Ohio regulations, including the PSD, NNSR and Title V regulations at the Eastlake, Lakeshore, Bay Shore and Ashtabula generating plants. The EPA s NOV alleges equipment replacements occurring during maintenance outages dating back to 1990 triggered the pre-construction permitting requirements under the PSD and NNSR programs. FGCO received a request for certain operating and maintenance information and planning information for these same generating plants and notification that the EPA is evaluating whether certain maintenance at the Eastlake generating plant may constitute a major modification under the NSR provision of the CAA. Later in 2009, FGCO also received another information request regarding emission projections for the Eastlake generating plant. FGCO intends to comply with the CAA, including the EPA s information requests but, at this time, is unable to predict the outcome of this matter.

In August 2000, AE received a letter from the EPA requesting that it provide information and documentation relevant to the operation and maintenance of the following ten electric generation facilities, which collectively include 22 generation units: Albright, Armstrong, Fort Martin, Harrison, Hatfield s Ferry, Mitchell, Pleasants, Rivesville, R. Paul Smith and Willow Island. The letter requested information under Section 114 of the CAA to determine compliance with the CAA and related requirements, including potential application of the NSR standards under the CAA, which can require the installation of additional air emission control equipment when the major modification of an existing facility results in an increase in emissions. AE has provided responsive information to this and a subsequent request but is unable to predict the outcome of this matter.

In May 2004, AE, AE Supply, MP and WP received a Notice of Intent to Sue Pursuant to CAA §7604 from the Attorneys General of New York, New Jersey and Connecticut and from the PA DEP, alleging that Allegheny performed major modifications in violation of the PSD provisions of the CAA at the following West Virginia coal-fired facilities: Albright Unit 3; Fort Martin Units 1 and 2; Harrison Units 1, 2 and 3; Pleasants Units 1 and 2 and Willow Island Unit 2. The Notice also alleged PSD violations at the Armstrong, Hatfield s Ferry and Mitchell generation facilities in Pennsylvania and identifies PA DEP as the lead agency regarding those facilities. In September 2004, AE, AE Supply, MP and WP received a separate Notice of Intent to Sue from the Maryland Attorney General that essentially mirrored the previous Notice.

In June 2005, the PA DEP and the Attorneys General of New York, New Jersey, Connecticut and Maryland filed suit against AE, AE Supply, MP, PE and WP in the United States District Court for the Western District of Pennsylvania alleging, among other things, that Allegheny performed major modifications in violation of the CAA and the Pennsylvania Air Pollution Control Act at the Hatfield s Ferry, Armstrong and Mitchell facilities in Pennsylvania. On January 17, 2006, the PA DEP and the Attorneys General filed an amended complaint. In May 2006, the District Court denied Allegheny s motion to dismiss the amended complaint. In July 2006, the Court determined that discovery would proceed regarding liability issues, but not remedies. Discovery on the liability phase closed on December 31, 2007, and summary judgment briefing was completed during the first quarter of 2008. In November 2008, the District Court issued a Memorandum Order denying all motions for summary judgment and establishing certain legal standards to govern at trial. In December 2009, a new trial judge was assigned to the case, who then entered an order granting a motion to reconsider the rulings in the November 2008 Memorandum Order. In April 2010, the new judge issued an opinion, again denying all motions for summary judgment and establishing certain legal standards to govern at trial. The non-jury trial on liability only was held in September 2010. Plaintiffs filed their proposed findings of fact and conclusions of law in December 2010, Allegheny made its related filings in February 2011 and plaintiffs filed their responses in April 2011. The parties are awaiting a decision from the District Court, but there is no deadline for that decision.

In September 2007, Allegheny also received a NOV from the EPA alleging NSR and PSD violations under the CAA, as well as Pennsylvania and West Virginia state laws at the Hatfield s Ferry and Armstrong generation facilities in Pennsylvania and the Fort Martin and Willow Island generation facilities in West Virginia.

FirstEnergy intends to vigorously defend against the CAA matters described above but cannot predict their outcomes.

State Air Quality Compliance

In early 2006, Maryland passed the Healthy Air Act, which imposes state-wide emission caps on SO_2 and NO_X, requires mercury emission reductions and mandates that Maryland join the RGGI and participate in that coalition s regional efforts to reduce CO_2 emissions. On April 20, 2007, Maryland became the 10th state to join the RGGI. The

Healthy Air Act provides a conditional exemption for the R. Paul Smith power station for NO_X, SO_2 and mercury, based on a PJM declaration that the station is vital to reliability in the Baltimore/Washington DC metropolitan area, which PJM determined in 2006. Pursuant to the legislation, the Maryland Department of the Environment (MDE) passed alternate NO_X and SO_2 limits for R. Paul Smith, which became effective in April 2009. However, R. Paul Smith is still required to meet the Healthy Air Act mercury reductions of 80% beginning in 2010. The statutory exemption does not extend to R. Paul Smith s CO_2 emissions. Maryland issued final regulations to implement RGGI requirements in February 2008. Ten RGGI auctions have been held through the end of calendar year 2010. RGGI allowances are also readily available in the allowance markets, affording another mechanism by which to secure necessary allowances. On March 14, 2011, MDE requested PJM perform an analysis to determine if termination of operation at R. Paul Smith would adversely impact the reliability of electrical service in the PJM region under current system conditions. FirstEnergy is unable to predict the outcome of this matter.

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In January 2010, the WVDEP issued a NOV for opacity emissions at Allegheny s Pleasants generating facility. FirstEnergy is discussing with WVDEP steps to resolve the NOV including installing a reagent injection system to reduce opacity.

National Ambient Air Quality Standards

The EPA s CAIR requires reductions of NOx and SO_2 emissions in two phases (2009/2010 and 2015), ultimately capping SO_2 emissions in affected states to 2.5 million tons annually and NOx emissions to 1.3 million tons annually. In 2008, the U.S. Court of Appeals for the District of Columbia Circuit vacated CAIR in its entirety and directed the EPA to redo its analysis from the ground up. In December 2008, the Court reconsidered its prior ruling and allowed CAIR to remain in effect to temporarily preserve its environmental values until the EPA replaces CAIR with a new rule consistent with the Court s opinion. The Court ruled in a different case that a cap-and-trade program similar to CAIR, called the NOx SIP Call, cannot be used to satisfy certain CAA requirements (known as reasonably available control technology) for areas in non-attainment under the 8-hour ozone NAAQS. In July 2010, the EPA proposed the Clean Air Transport Rule (CATR) to replace CAIR, which remains in effect until the EPA finalizes CATR. CATR requires reductions of NOx and SO_2 emissions in two phases (2012 and 2014), ultimately capping SO_2 emissions in affected states to 2.6 million tons annually and NOx emissions to 1.3 million tons annually. The EPA proposed a preferred regulatory approach that allows trading of NOx and SO_2 emission allowances between power plants located in the same state and severely limits interstate trading of NOx and SO_2 emission allowances. The EPA also requested comment on two alternative approaches the first eliminates interstate trading of NOx and SO_2 emission allowances and the second eliminates trading of NOx and SO_2 emission allowances in its entirety. Depending on the actions taken by the EPA with respect to CATR, the proposed MACT regulations discussed below and any future regulations that are ultimately implemented, FGCO s future cost of compliance may be substantial. Management is currently assessing the impact of these environmental proposals and other factors on FGCO s facilities, particularly on the operation of its smaller, non-supercritical units. For example, as disclosed herein, management decided to idle certain units or operate them on a seasonal basis until developments clarify.

Hazardous Air Pollutant Emissions

On March 16, 2011, the EPA released its MACT proposal to establish emission standards for mercury, hydrochloric acid and various metals for electric generating units. Depending on the action taken by the EPA and how any future regulations are ultimately implemented, FirstEnergy s future cost of compliance with MACT regulations may be substantial and changes to FirstEnergy s operations may result.

Climate Change

There are a number of initiatives to reduce GHG emissions under consideration at the federal, state and international level. At the federal level, members of Congress have introduced several bills seeking to reduce emissions of GHG in the United States, and the House of Representatives passed one such bill, the American Clean Energy and Security Act of 2009, in June 2009. The Senate continues to consider a number of measures to regulate GHG emissions. President Obama has announced his Administration s New Energy for America Plan that includes, among other provisions, proposals to ensure that 10% of electricity used in the United States comes from renewable sources by 2012, to increase to 25% by 2025, to implement an economy-wide cap-and-trade program to reduce GHG emissions by 80% by 2050. Certain states, primarily the northeastern states participating in the RGGI and western states, led by California, have coordinated efforts to develop regional strategies to control emissions of certain GHGs.

In September 2009, the EPA finalized a national GHG emissions collection and reporting rule that required FirstEnergy to measure GHG emissions commencing in 2010 and will require it to submit reports commencing in 2011. In December 2009, the EPA released its final Endangerment and Cause or Contribute Findings for Greenhouse Gases under the Clean Air Act. The EPA s finding concludes that concentrations of several key GHGs increase the threat of climate change and may be regulated as air pollutants under the CAA. In April 2010, the EPA finalized new GHG standards for model years 2012 to 2016 passenger cars, light-duty trucks and medium-duty passenger vehicles and clarified that GHG regulation under the CAA would not be triggered for electric generating plants and other stationary sources until January 2, 2011, at the earliest. In May 2010, the EPA finalized new thresholds for GHG emissions that define when permits under the CAA s NSR program would be required. The EPA established an emissions applicability threshold of 75,000 tons per year (tpy) of carbon dioxide equivalents (CO2e) effective

January 2, 2011 for existing facilities under the CAA s PSD program. Until July 1, 2011, this emissions applicability threshold will only apply if PSD is triggered by non-CO_2 pollutants.

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At the international level, the Kyoto Protocol, signed by the U.S. in 1998 but never submitted for ratification by the U.S. Senate, was intended to address global warming by reducing the amount of man-made GHG, including CO_2, emitted by developed countries by 2012. A December 2009 U.N. Climate Change Conference in Copenhagen did not reach a consensus on a successor treaty to the Kyoto Protocol, but did take note of the Copenhagen Accord, a non-binding political agreement that recognized the scientific view that the increase in global temperature should be below two degrees Celsius; includes a commitment by developed countries to provide funds, approaching $30 billion over the next three years with a goal of increasing to $100 billion by 2020; and establishes the Copenhagen Green Climate Fund to support mitigation, adaptation, and other climate-related activities in developing countries. To the extent that they have become a party to the Copenhagen Accord, developed economies, such as the European Union, Japan, Russia and the United States, would commit to quantified economy-wide emissions targets from 2020, while developing countries, including Brazil, China and India, would agree to take mitigation actions, subject to their domestic measurement, reporting and verification.

In 2009, the U.S. Court of Appeals for the Second Circuit and the U.S. Court of Appeals for the Fifth Circuit reversed and remanded lower court decisions that had dismissed complaints alleging damage from GHG emissions on jurisdictional grounds. However, a subsequent ruling from the U.S. Court of Appeals for the Fifth Circuit reinstated the lower court dismissal of a complaint alleging damage from GHG emissions. These cases involve common law tort claims, including public and private nuisance, alleging that GHG emissions contribute to global warming and result in property damages. The U.S. Supreme Court granted a writ of certiorari to review the decision of the Second Circuit. Oral argument was held on April 19, 2011, and a decision is expected by July 2011. While FirstEnergy is not a party to this litigation, FirstEnergy and/or one or more of its subsidiaries could be named in actions making similar allegations.

FirstEnergy cannot currently estimate the financial impact of climate change policies, although potential legislative or regulatory programs restricting CO_2 emissions, or litigation alleging damages from GHG emissions, could require significant capital and other expenditures or result in changes to its operations. The CO_2 emissions per KWH of electricity generated by FirstEnergy is lower than many of its regional competitors due to its diversified generation sources, which include low or non-CO_2 emitting gas-fired and nuclear generators.

Clean Water Act

Various water quality regulations, the majority of which are the result of the federal Clean Water Act and its amendments, apply to FirstEnergy s plants. In addition, the states in which FirstEnergy operates have water quality standards applicable to FirstEnergy s operations.

The EPA established new performance standards under Section 316(b) of the Clean Water Act for reducing impacts on fish and shellfish from cooling water intake structures at certain existing electric generating plants. The regulations call for reductions in impingement mortality (when aquatic organisms are pinned against screens or other parts of a cooling water intake system) and entrainment (which occurs when aquatic life is drawn into a facility s cooling water system). The EPA has taken the position that until further rulemaking occurs, permitting authorities should continue the existing practice of applying their best professional judgment to minimize impacts on fish and shellfish from cooling water intake structures. In April 2009, the U.S. Supreme Court reversed one significant aspect of the Second Circuit s opinion and decided that Section 316(b) of the Clean Water Act authorizes the EPA to compare costs with benefits in determining the best technology available for minimizing adverse environmental impact at cooling water intake structures. On March 28, 2011, the EPA released a new proposed regulation under Section 316(b) of the Clean Water Act generally requiring fish impingement to be reduced to a 12% annual average and studies to be conducted at the majority of our existing generating facilities to assist permitting authorities to determine whether and what site-specific controls, if any, would be required to reduce entrainment of aquatic life. FirstEnergy is studying various control options and their costs and effectiveness, including pilot testing of reverse louvers in a portion of the Bay Shore power plant s water intake channel to divert fish away from the plant s water intake system. In November 2010, the Ohio EPA issued a permit for the Bay Shore power plant requiring installation of reverse louvers in its entire water intake channel by December 31, 2014. Depending on the results of such studies and the EPA s further rulemaking and any final action taken by the states exercising best professional judgment, the future costs of compliance with these standards may require material capital expenditures.

In April 2011, the U.S. Attorney s Office in Cleveland, Ohio advised FGCO that it is no longer considering prosecution under the Clean Water Act and the Migratory Bird Treaty Act for three petroleum spills at the Edgewater, Lakeshore and Bay Shore plants which occurred on November 1, 2005, January 26, 2007 and February 27, 2007. This matter has been referred back to EPA for civil enforcement and FGCO is unable to predict the outcome of this matter.

Monongahela River Water Quality

In late 2008, the PA DEP imposed water quality criteria for certain effluents, including TDS and sulfate concentrations in the Monongahela River, on new and modified sources, including the scrubber project at the Hatfield s Ferry generation facility. These criteria are reflected in the current PA DEP water discharge permit for that project. AE Supply appealed the PA DEP s permitting decision, which would require it to incur significant costs or negatively affect its ability to operate the scrubbers as designed. Preliminary studies indicate an initial capital investment in excess of $150 million in order to install technology to meet the TDS and sulfate limits in the permit. The permit has been independently appealed by Environmental Integrity Project and Citizens Coal Council, which seeks to impose more stringent technology-based effluent limitations. Those same parties have intervened in the appeal filed by AE Supply, and both appeals have been consolidated for discovery purposes. An order has been entered that stays the permit limits that AE Supply has challenged while the appeal is pending. The hearing is scheduled to begin on September 13, 2011. AE Supply intends to vigorously pursue these issues, but cannot predict the outcome of these appeals.

In a parallel rulemaking, the PA DEP recommended, and in August 2010, the Pennsylvania Environmental Quality Board issued, a final rule imposing end-of-pipe TDS effluent limitations. FirstEnergy could incur significant costs for additional control equipment to meet the requirements of this rule, although its provisions do not apply to electric generating units until the end of 2018, and then only if the EPA has not promulgated TDS effluent limitation guidelines applicable to such units.

In December 2010, PA DEP submitted its Clean Water Act 303(d) list to the EPA with a recommended sulfate impairment designation for an approximately 68 mile stretch of the Monongahela River north of the West Virginia border. EPA has not acted on PA DEP s recommendation. If the designation is approved, Pennsylvania will then need to develop a TMDL limit for the river, a process that will take about five years. Based on the stringency of the TMDL, FirstEnergy may incur significant costs to reduce sulfate discharges into the Monongahela River from its Hatfield s Ferry and Mitchell facilities in Pennsylvania and its Fort Martin facility in West Virginia.

In October 2009, the WVDEP issued the water discharge permit for the Fort Martin generation facility. Similar to the Hatfield s Ferry water discharge permit issued for the scrubber project, the Fort Martin permit imposes effluent limitations for TDS and sulfate concentrations. The permit also imposes temperature limitations and other effluent limits for heavy metals that are not contained in the Hatfield s Ferry water permit. Concurrent with the issuance of the Fort Martin permit, WVDEP also issued an administrative order that sets deadlines for MP to meet certain of the effluent limits that are effective immediately under the terms of the permit. MP appealed the Fort Martin permit and the administrative order. The appeal included a request to stay certain of the conditions of the permit and order while the appeal is pending, which was granted pending a final decision on appeal and subject to WVDEP moving to dissolve the stay. The appeals have been consolidated. MP moved to dismiss certain of the permit conditions for the failure of the WVDEP to submit those conditions for public review and comment during the permitting process. An agreed-upon order that suspends further action on this appeal, pending WVDEP s release for public review and comment on those conditions, was entered on August 11, 2010. The stay remains in effect during that process. The current terms of the Fort Martin permit would require MP to incur significant costs or negatively affect operations at Fort Martin. Preliminary information indicates an initial capital investment in excess of the capital investment that may be needed at Hatfield s Ferry in order to install technology to meet the TDS and sulfate limits in the Fort Martin permit, which technology may also meet certain of the other effluent limits in the permit. Additional technology may be needed to meet certain other limits in the permit. MP intends to vigorously pursue these issues but cannot predict the outcome of these appeals.

Regulation of Waste Disposal

Federal and state hazardous waste regulations have been promulgated as a result of the Resource Conservation and Recovery Act of 1976, as amended, and the Toxic Substances Control Act of 1976. Certain fossil-fuel combustion residuals, such as coal ash, were exempted from hazardous waste disposal requirements pending the EPA s evaluation of the need for future regulation. In February 2009, the EPA requested comments from the states on options for regulating coal combustion residuals, including whether they should be regulated as hazardous or non-hazardous waste.

In December 2009, in an advanced notice of public rulemaking, the EPA asserted that the large volumes of coal combustion residuals produced by electric utilities pose significant financial risk to the industry. In May 2010, the EPA proposed two options for additional regulation of coal combustion residuals, including the option of regulation as a special waste under the EPA s hazardous waste management program which could have a significant impact on the management, beneficial use and disposal of coal combustion residuals. FirstEnergy s future cost of compliance with any coal combustion residuals regulations that may be promulgated could be substantial and would depend, in part, on the regulatory action taken by the EPA and implementation by the EPA or the states.

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The Utility Registrants have been named as potentially responsible parties 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 potentially responsible parties for a particular site may be liable on a joint and several basis. Environmental liabilities that are considered probable have been recognized on the consolidated balance sheet as of March 31, 2011, based on estimates of the total costs of cleanup, the Utility Registrants proportionate responsibility for such costs and the financial ability of other unaffiliated entities to pay. Total liabilities of approximately $104 million (JCP&L $69 million, TE $1 million, CEI $1 million, FGCO $1 million and FirstEnergy $32 million) have been accrued through March 31, 2011. Included in the total are accrued liabilities of approximately $64 million for environmental remediation of former manufactured gas plants and gas holder facilities in New Jersey, which are being recovered by JCP&L through a non-bypassable SBC.

(C) OTHER LEGAL PROCEEDINGS

Power Outages and Related Litigation

In July 1999, the Mid-Atlantic States experienced a severe heat wave, which resulted in power outages throughout the service territories of many electric utilities, including JCP&L. Two class action lawsuits (subsequently consolidated into a single proceeding) were filed in New Jersey Superior Court in July 1999 against JCP&L, GPU and other GPU companies, seeking compensatory and punitive damages due to the outages. After various motions, rulings and appeals, the Plaintiffs claims for consumer fraud, common law fraud, negligent misrepresentation, strict product liability and punitive damages were dismissed, leaving only the negligence and breach of contract causes of actions. On July 29, 2010, the Appellate Division upheld the trial court s decision decertifying the class. Plaintiffs have filed, and JCP&L has opposed, a motion for leave to appeal to the New Jersey Supreme Court. In November 2010, the Supreme Court issued an order denying Plaintiffs motion. The Court s order effectively ends the class action attempt, and leaves only nine (9) plaintiffs to pursue their respective individual claims. The remaining individual plaintiffs have not taken any affirmative steps to pursue their individual claims.

Nuclear Plant Matters

Under NRC regulations, FirstEnergy must ensure that adequate funds will be available to decommission its nuclear facilities. As of March 31, 2011, FirstEnergy had approximately $2 billion invested in external trusts to be used for the decommissioning and environmental remediation of Davis-Besse, Beaver Valley, Perry and TMI-2. FirstEnergy provides an additional $15 million parental guarantee associated with the funding of decommissioning costs for these units. As required by the NRC, FirstEnergy annually recalculates and adjusts the amount of its parental guarantee, as appropriate. The values of FirstEnergy s nuclear decommissioning trusts fluctuate based on market conditions. If the value of the trusts decline by a material amount, FirstEnergy s obligation to fund the trusts may increase. Disruptions in the capital markets and their effects on particular businesses and the economy could also affect the values of the nuclear decommissioning trusts. The NRC issued guidance anticipating an increase in low-level radioactive waste disposal costs associated with the decommissioning of FirstEnergy s nuclear facilities. On March 28, 2011, FENOC submitted its biennial report on nuclear decommissioning funding to the NRC. This submittal identified a total shortfall in nuclear decommissioning funding for Beaver Valley Unit 1 and Perry of approximately $92.5 million. This estimate encompasses the shortfall covered by the existing $15 million parental guarantee. FENOC agreed to increase the parental guarantee to $95 million within 90 days of the submittal.

In August 2010, FENOC submitted an application to the NRC for renewal of the Davis-Besse Nuclear Power Station operating license for an additional twenty years, until 2037. By an order dated April 26, 2011, the NRC Atomic Safety and Licensing Board (ASLB) granted a hearing on the Davis-Besse license renewal application to a group of petitioners. By this order, the ASLB also admitted two contentions regarding (1) a combination of renewable alternatives to the renewal of Davis-Besse s operating license, and (2) the cost of mitigating a severe accident at Davis-Besse. FENOC is currently evaluating these developments and considering an appropriate response. On April 14, 2011, a group of environmental organizations petitioned the NRC Commissioners to suspend all pending nuclear license renewal proceedings, including the Davis-Besse proceeding, to ensure that any safety and environmental implications of the Fukushima Daiichi Nuclear Power Station event in Japan are considered.

In January 2004, subsidiaries of FirstEnergy filed a lawsuit in the U.S. Court of Federal Claims seeking damages in connection with costs incurred at the Beaver Valley, Davis-Besse and Perry Nuclear facilities as a result of the DOE failure to begin accepting spent nuclear fuel on January 31, 1998. DOE was required to so commence accepting spent nuclear fuel by the Nuclear Waste Policy Act (42 USC 10101 et seq) and the contracts entered into by the DOE and the owners and operators of these facilities pursuant to the Act. On January 18, 2011, the parties, FirstEnergy and DOJ, filed a joint status report that established a schedule for the litigation of these claims. FirstEnergy filed damages schedules and disclosures with the DOJ on February 11, 2011, seeking approximately $57 million in damages for delay costs incurred through September 30, 2010. The damage claim is subject to review and audit by DOE.

Other Legal Matters

In February 2010, a class action lawsuit was filed in Geauga County Court of Common Pleas against FirstEnergy, CEI and OE seeking declaratory judgment and injunctive relief, as well as compensatory, incidental and consequential damages, on behalf of a class of customers related to the reduction of a discount that had previously been in place for residential customers with electric heating, electric water heating, or load management systems. The reduction in the discount was approved by the PUCO. In March 2010, the named-defendant companies filed a motion to dismiss the case due to the lack of jurisdiction of the court of common pleas. The court granted the motion to dismiss on September 7, 2010. The plaintiffs appealed the decision to the Court of Appeals of Ohio, which has not yet rendered an opinion.

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

FirstEnergy accrues legal liabilities only when it concludes that it is probable that it has an obligation for such costs and can reasonably estimate the amount of such costs. If it were ultimately determined that FirstEnergy or its subsidiaries have legal liability or are otherwise made subject to liability based on the above matters, it could have a material adverse effect on FirstEnergy s or its subsidiaries financial condition, results of operations and cash flows.

10. REGULATORY MATTERS

(A) RELIABILITY INITIATIVES

Federally-enforceable mandatory reliability standards apply to the bulk electric system and impose certain operating, record-keeping and reporting requirements on the Utilities, FES, FGCO, FENOC, and ATSI and TrAIL Company. The NERC, as the ERO is charged with establishing and enforcing these reliability standards, although it has delegated day-to-day implementation and enforcement of these reliability standards to eight regional entities, including Reliability*First* Corporation. All of FirstEnergy s facilities are located within the Reliability*First* region. FirstEnergy actively participates in the NERC and Reliability*First* stakeholder processes, and otherwise monitors and manages its companies in response to the ongoing development, implementation and enforcement of the reliability standards implemented and enforced by the Reliability*First* Corporation.

FirstEnergy believes that it generally is in compliance with all currently-effective and enforceable reliability standards. Nevertheless, in the course of operating its extensive electric utility systems and facilities, FirstEnergy occasionally learns of isolated facts or circumstances that could be interpreted as excursions from the reliability standards. If and when such items are found, FirstEnergy develops information about the item and develops a remedial response to the specific circumstances, including in appropriate cases self-reporting an item to Reliability*First*. Moreover, it is clear that the NERC, Reliability*First* and the FERC will continue to refine existing reliability standards as well as to develop and adopt new reliability standards. The financial impact of complying with new or amended standards cannot be determined at this time; however, 2005 amendments to the FPA provide that all prudent costs incurred to comply with the new reliability standards be recovered in rates. Still, any future inability on FirstEnergy s part to comply with the reliability standards for its bulk power system could result in the imposition of financial penalties that could have a material adverse effect on its financial condition, results of operations and cash flows.

On December 9, 2008, a transformer at JCP&L s Oceanview substation failed, resulting in an outage on certain bulk electric system (transmission voltage) lines out of the Oceanview and Atlantic substations resulting in customers losing power for up to eleven hours. On March 31, 2009, the NERC initiated a Compliance Violation Investigation in order to determine JCP&L s contribution to the electrical event and to review any potential violation of NERC Reliability Standards associated with the event. NERC has submitted first and second Requests for Information regarding this and another related matter. JCP&L is complying with these requests. JCP&L is not able to predict what actions, if any, that the NERC may take with respect to this matter.

On August 23, 2010, FirstEnergy self-reported to Reliability*First* a vegetation encroachment event on a Met-Ed 230 kV line. This event did not result in a fault, outage, operation of protective equipment, or any other meaningful electric effect on any FirstEnergy transmission facilities or systems. On August 25, 2010, Reliability*First* issued a Notice of Enforcement to investigate the incident. FirstEnergy submitted a data response to Reliability*First* on September 27, 2010. In March 2011, Reliability*First* submitted its proposed findings and settlement. At this time, FirstEnergy is evaluating Reliability*First* s proposal and is unable to predict the final outcome of this investigation. Allegheny has been subject to routine audits with respect to its compliance with applicable reliability standards and has settled certain related issues. In addition, Reliability*First* is currently conducting certain violation investigations with regard to matters of compliance by Allegheny.

(B) MARYLAND

In 1999, Maryland adopted electric industry restructuring legislation, which gave PE s Maryland retail electric customers the right to choose their electricity generation suppliers. PE remained obligated to provide standard offer generation service (SOS) at capped rates to residential and non-residential customers for various periods. The longest such period, for residential customers, expired on December 31, 2008. PE implemented a rate stabilization plan in 2007 that was designed to transition customers from capped generation rates to rates based on market prices and that concluded on December 31, 2010. PE s transmission and distribution rates for all customers are subject to traditional regulated utility ratemaking (i.e., cost-based rates).

By statute enacted in 2007, the obligation of Maryland utilities to provide SOS to residential and small commercial customers, in exchange for recovery of their costs plus a reasonable profit, was extended indefinitely. The legislation also established a five-year cycle (to begin in 2008) for the MDPSC to report to the legislature on the status of SOS. In August 2007, PE filed a plan for seeking bids to serve its Maryland residential load for the period after the expiration of rate caps. The MDPSC approved the plan and PE now conducts rolling auctions to procure the power supply necessary to serve its customer load. However, the terms on which PE will provide SOS to residential customers after the settlement beyond 2012 will depend on developments with respect to SOS in Maryland between now and then, including but not limited to possible MDPSC decisions in the proceedings discussed below.

The MDPSC opened a new docket in August 2007 to consider matters relating to possible managed portfolio approaches to SOS and other matters. Phase II of the case addressed utility purchases or construction of generation, bidding for procurement of demand response resources and possible alternatives if the TrAIL and PATH projects were delayed or defeated. It is unclear when the MDPSC will issue its findings in this and other SOS-related pending proceedings discussed below.

In September 2009, the MDPSC opened a new proceeding to receive and consider proposals for construction of new generation resources in Maryland. In December 2009, Governor Martin O Malley filed a letter in this proceeding in which he characterized the electricity market in Maryland as a failure and urged the MDPSC to use its existing authority to order the construction of new generation in Maryland, vary the means used by utilities to procure generation and include more renewables in the generation mix. In August 2010, the MDPSC opened another new proceeding to solicit comments on the PJM RPM process. Public hearings on the comments were held in October 2010. In December 2010, the MDPSC issued an order soliciting comments on a model request for proposal for solicitation of long-term energy commitments by Maryland electric utilities. PE and numerous other parties filed comments, and at this time no further proceedings have been set by the MDPSC in this matter.

In September 2007, the MDPSC issued an order that required the Maryland utilities to file detailed plans for how they will meet the EmPOWER Maryland proposal that, in Maryland, electric consumption be reduced by 10% and electricity demand be reduced by 15%, in each case by 2015. In October 2007, PE filed its initial report on energy efficiency, conservation and demand reduction plans in connection with this order. The MDPSC conducted hearings on PE s and other utilities plans in November 2007 and May 2008.

In a related development, the Maryland legislature in 2008 adopted a statute codifying the EmPOWER Maryland goals. In 2008, PE filed its comprehensive plans for attempting to achieve those goals, asking the MDPSC to approve programs for residential, commercial, industrial, and governmental customers, as well as a customer education program, and a pilot deployment of Advanced Utility Infrastructure (AUI) that Allegheny had previously tested in West Virginia. The MDPSC ultimately approved the programs in August 2009 after certain modifications had been made as required by the MDPSC, and approved cost recovery for the programs in October 2009. Expenditures were estimated to be approximately $101 million and would be recovered over the following six years. The AUI pilot was placed on a separate track to be re-examined after further discussion with the Staff of the MDPSC and other stakeholders. Meanwhile, extensive meetings with the MDPSC Staff and other stakeholders to discuss details of PE s plans for additional and improved programs for the period 2012-2014 began in April 2011.

In March 2009, the Maryland PSC issued an order suspending until further notice the right of all electric and gas utilities in the state to terminate service to residential customers for non-payment of bills. The MDPSC subsequently issued an order making various rule changes relating to terminations, payment plans, and customer deposits that make it more difficult for Maryland utilities to collect deposits or to terminate service for non-payment. PE and several other utilities filed requests for reconsideration of various parts of the order, which were denied. The MDPSC is continuing to conduct hearings and collect data on payment plan and related issues and has adopted a set of proposed regulations that expand the summer and winter severe weather termination moratoria when temperatures are very high or very low, from one day, as provided by statute, to three days on each occurrence.

On March 24, 2011, the MDPSC held an initial hearing to discuss possible new regulations relating to service interruptions, storm response, call center metrics, and related reliability standards. The proposed rules included provisions for civil penalties for non-compliance. Numerous parties filed comments on the proposed rules and participated in the hearing, with many noting issues of cost and practicality relating to implementation. Concurrently, the Maryland legislature is considering a bill addressing the same topics. The final bill passed on April 11, 2011, requires the MDPSC to promulgate rules by July 1, 2012 that address service interruptions, downed wire response, customer communication, vegetation management, equipment inspection, and annual reporting. In crafting the regulations, the MDPSC is directed to consider cost-effectiveness, and may adopt different standards for different utilities based on such factors as system design and existing infrastructure, geography, and customer density. Beginning in July 2013, the MDPSC is to assess each utility s compliance with the standards, and may assess penalties of up to $25,000 per day per violation. The MDPSC has ordered that a working group of utilities, regulators, and other interested stakeholders meet to address the topics of the proposed rules.

In December 2009, PE filed an application with the MDPSC for authorization to construct the Maryland portions of the PATH Project to be owned by PATH Allegheny Maryland Transmission Company, LLC, which is owned by Potomac Edison and PATH-Allegheny. On February 28, 2011, PE withdrew its application. See Transmission Expansion in the Federal Regulation and Rate Matters section for further discussion of this matter.

(C) NEW JERSEY

JCP&L is permitted to defer for future collection from customers the amounts by which its costs of supplying BGS to non-shopping customers, costs incurred under NUG agreements, and certain other stranded costs, exceed amounts collected through BGS and NUG rates and market sales of NUG energy and capacity. As of March 31, 2011, the accumulated deferred cost balance was a credit of approximately $102 million. To better align the recovery of expected costs, in July 2010, JCP&L filed a request to decrease the amount recovered for the costs incurred under the NUG agreements by $180 million annually, which the NJBPU approved, allowing the change in rates to become effective March 1, 2011.

In March 2009 and again in February 2010, JCP&L filed annual SBC Petitions with the NJBPU that included a requested zero level of recovery of TMI-2 decommissioning costs based on an updated TMI-2 decommissioning cost analysis dated January 2009 estimated at $736 million (in 2003 dollars). Both matters are currently pending before the NJBPU.

(D) OHIO

The Ohio Companies operate under an ESP, which expires on May 31, 2011, that provides for generation supplied through a CBP. The ESP also allows the Ohio Companies to collect a delivery service improvement rider (Rider DSI) at an overall average rate of $0.002 per KWH for the period of April 1, 2009 through December 31, 2011. The Ohio Companies currently purchase generation at the average wholesale rate of a CBP conducted in May 2009. FES is one of the suppliers to the Ohio Companies through the May 2009 CBP. The PUCO approved a $136.6 million distribution rate increase for the Ohio Companies in January 2009, which went into effect on January 23, 2009 for OE ($68.9 million) and TE ($38.5 million) and on May 1, 2009 for CEI ($29.2 million).

In March 2010, the Ohio Companies filed an application for a new ESP, which the PUCO approved in August 2010, with certain modifications. The new ESP will go into effect on June 1, 2011 and conclude on May 31, 2014. The material terms of the new ESP include: a CBP similar to the one used in May 2009 and the one proposed on the October 2009 MRO filing (initial auctions held on October 20, 2010 and January 25, 2011); a load cap of no less than 80%, which also applies to tranches assigned post-auction; a 6% generation discount to certain low income customers provided by the Ohio Companies through a bilateral wholesale contract with FES; no increase in base distribution rates through May 31, 2014; and a new distribution rider, Delivery Capital Recovery Rider (Rider DCR), to recover a return of, and on, capital investments in the delivery system. Rider DCR substitutes for Rider DSI which terminates under the current ESP. The Ohio Companies also agreed not to recover from retail customers certain costs related to the companies integration into PJM for the longer of the five-year period from June 1, 2011 through May 31, 2015 or when the amount of costs avoided by customers for certain types of products totals $360 million dependent on the outcome of certain PJM proceedings, agreed to establish a $12 million fund to assist low income customers over the term of the ESP and agreed to additional matters related to energy efficiency and alternative energy requirements.

Many of the existing riders approved in the previous ESP remain in effect, with some modifications. The new ESP resolved proceedings pending at the PUCO regarding corporate separation, elements of the smart grid proceeding and expenses related to the ESP.

Under the provisions of SB221, the Ohio Companies are required to implement energy efficiency programs that will achieve a total annual energy savings equivalent to approximately 166,000 MWH in 2009, 290,000 MWH in 2010, 410,000 MWH in 2011, 470,000 MWH in 2012 and 530,000 MWH in 2013, with additional savings required through 2025. Utilities are also required to reduce peak demand in 2009 by 1%, with an additional 0.75% reduction each year thereafter through 2018.

In December 2009, the Ohio Companies filed the required three year portfolio plan seeking approval for the programs they intend to implement to meet the energy efficiency and peak demand reduction requirements for the 2010-2012 period. The Ohio Companies expect that all costs associated with compliance will be recoverable from customers. The PUCO issued an Opinion and Order generally approving the Ohio Companies 3-year plan, and the Companies are in the process of implementing those programs included in the Plan. Because of the delay in issuing the Order, the launch of the programs included in the plan for 2010 was delayed and will launch during the second quarter of this year. As a result, OE fell short of its statutory 2010 energy efficiency and peak demand reduction benchmarks. Therefore, on January 11, 2011, it requested that its 2010 energy efficiency and peak demand reduction benchmarks be amended to actual levels achieved in 2010. Moreover, because the PUCO indicated, when approving the 2009 benchmark request, that it would modify the Companies 2010 (and 2011 and 2012) energy efficiency benchmarks when addressing the portfolio plan, the Ohio Companies were not certain of their 2010 energy efficiency obligations. Therefore, CEI and TE (each of which achieved its 2010 energy efficiency and peak demand reduction statutory benchmarks) also requested an amendment if and only to the degree one was deemed necessary to bring these them into compliance with their yet-to-be-defined modified benchmarks. Failure to comply with the benchmarks or to obtain such an amendment may subject the Companies to an assessment by the PUCO of a penalty. In addition to approving the programs included in the plan, with only minor modifications, the PUCO authorized the Companies to recover all costs related to the original CFL program that the Ohio Companies had previously suspended at the request of the PUCO. Applications for Rehearing were filed on April 22, 2011, regarding portions of the PUCO s decision, including the method for calculating savings and certain changes made by the PUCO to specific programs.

Additionally under SB221, electric utilities and electric service companies are required to serve part of their load from renewable energy resources equivalent to 0.25% of the KWH they served in 2009. In August and October 2009, the Ohio Companies conducted RFPs to secure RECs. The RFPs sought RECs, including solar RECs and RECs generated in Ohio in order to meet the Ohio Companies alternative energy requirements as set forth in SB221 for 2009, 2010 and 2011. The RECs acquired through these two RFPs were used to help meet the renewable energy requirements established under SB221 for 2009, 2010 and 2011. In March 2010, the PUCO found that there was an insufficient quantity of solar energy resources reasonably available in the market. The PUCO reduced the Ohio Companies aggregate 2009 benchmark to the level of solar RECs the Ohio Companies acquired through their 2009 RFP processes, provided the Ohio Companies 2010 alternative energy requirements be increased to include the shortfall for the 2009 solar REC benchmark. FES also applied for a force majeure determination from the PUCO regarding a portion of their compliance with the 2009 solar energy resource benchmark. On February 23, 2011, the PUCO granted FES force majeure request for 2009 and increased its 2010 benchmark by the amount of SRECs that FES was short of in its 2009 benchmark. In July 2010, the Ohio Companies initiated an additional RFP to secure RECs and solar RECs needed to meet the Ohio Companies alternative energy requirements as set forth in SB221 for 2010 and 2011 and executed related contracts in August 2010. On April 15, 2011, the Ohio Companies filed an application seeking an amendment to each of their 2010 alternative energy requirements for solar RECs generated in Ohio on the basis that an insufficient quantity of solar resources are available in the market but reflecting solar RECs that they have obtained and providing additional information regarding efforts to secure solar RECs. The PUCO has not yet acted on that application.

In February 2010, OE and CEI filed an application with the PUCO to establish a new credit for all-electric customers. In March 2010, the PUCO ordered that rates for the affected customers be set at a level that will provide bill impacts commensurate with charges in place on December 31, 2008 and authorized the Ohio Companies to defer incurred costs equivalent to the difference between what the affected customers would have paid under previously existing rates and what they pay with the new credit in place. Tariffs implementing this new credit went into effect in March 2010. In April 2010, the PUCO issued a Second Entry on Rehearing that expanded the group of customers to which the new credit would apply and authorized deferral for the associated additional amounts. The PUCO also stated that it expected that the new credit would remain in place through at least the 2011 winter season, and charged its staff to work with parties to seek a long term solution to the issue. Tariffs implementing this newly expanded credit went into effect in May 2010 and the proceeding remains open. The hearing on the matter was held in February 2011. The matter has now been briefed and the Ohio Companies await the PUCO s decision.

(E) PENNSYLVANIA

The PPUC entered an Order on March 3, 2010 that denied the recovery of marginal transmission losses through the TSC rider for the period of June 1, 2007 through March 31, 2008, directed Met-Ed and Penelec to submit a new tariff or tariff supplement reflecting the removal of marginal transmission losses from the TSC, and instructed Met-Ed and Penelec to work with the various intervening parties to file a recommendation to the PPUC regarding the establishment of a separate account for all marginal transmission losses collected from ratepayers plus interest to be used to mitigate future generation rate increases beginning January 1, 2011. In March 2010, Met-Ed and Penelec filed a Petition with the PPUC requesting that it stay the portion of the March 3, 2010 Order requiring the filing of tariff supplements to end collection of costs for marginal transmission losses. The PPUC granted the requested stay until December 31, 2010. Pursuant to the PPUC s order, Met-Ed and Penelec filed plans to establish separate accounts for marginal transmission loss revenues and related interest and carrying charges and for the use of these funds to mitigate future generation rate increases which the PPUC approved. In April 2010, Met-Ed and Penelec filed a Petition for Review with the Commonwealth Court of Pennsylvania appealing the PPUC s March 3, 2010 Order. The argument before the Commonwealth Court, en banc, was held in December 2010. Although the ultimate outcome of this matter cannot be determined at this time, Met-Ed and Penelec believe that they should prevail in the appeal and therefore expect to fully recover the approximately $252.7 million ($188.0 million for Met-Ed and $64.7 million for Penelec) in marginal transmission losses for the period prior to January 1, 2011.

In May 2008, May 2009 and May 2010, the PPUC approved Met-Ed s and Penelec s annual updates to their TSC rider for the annual periods between June 1, 2008 to December 31, 2010, including marginal transmission losses as approved by the PPUC, although the recovery of marginal losses will be subject to the outcome of the proceeding related to the 2008 TSC filing as described above. The PPUC s approval in May 2010 authorized an increase to the TSC for Met-Ed s customers to provide for full recovery by December 31, 2010.

Met-Ed and Penelec filed with the PPUC a generation procurement plan covering the period January 1, 2011 through May 31, 2013. The plan is designed to provide adequate and reliable service through a prudent mix of long-term, short-term and spot market generation supply with a staggered procurement schedule that varies by customer class, using a descending clock auction. In August 2009, the parties to the proceeding filed a settlement agreement of all but two issues, and the PPUC entered an Order approving the settlement and the generation procurement plan in November 2009. Generation procurement began in January 2010.

In February 2010, Penn filed a Petition for Approval of its Default Service Plan for the period June 1, 2011 through May 31, 2013. In July 2010, the parties to the proceeding filed a Joint Petition for Settlement of all issues. Although the PPUC s Order approving the Joint Petition held that the provisions relating to the recovery of MISO exit fees and one-time PJM integration costs (resulting from Penn s June 1, 2011 exit from MISO and integration into PJM) were approved, it made such provisions subject to the approval of cost recovery by FERC. Therefore, Penn may not put these provisions into effect until FERC has approved the recovery and allocation of MISO exit fees and PJM integration costs.

Pennsylvania adopted Act 129 in 2008 to address issues such as: energy efficiency and peak load reduction; generation procurement; time-of-use rates; smart meters; and alternative energy. Among other things, Act 129 required utilities to file with the PPUC an energy efficiency and peak load reduction plan, or EE&C Plan, by July 1, 2009, setting forth the utilities plans to reduce energy consumption by a minimum of 1% and 3% by May 31, 2011 and May 31, 2013, respectively, and to reduce peak demand by a minimum of 4.5% by May 31, 2013. Act 129 also required utilities to file with the PPUC a Smart Meter Implementation Plan (SMIP).

The PPUC entered an Order in February 2010 giving final approval to all aspects of the EE&C Plans of Met-Ed, Penelec and Penn and the tariff rider with rates effective March 1, 2010.

WP filed its original EE&C Plan in June 2009, which the PPUC approved, in large part, by Opinion and Order entered in October 2009. In November 2009, the Office of Consumer Advocate (OCA) filed an appeal with the Commonwealth Court of the PPUC s October Order. The OCA contends that the PPUC s Order failed to include WP s costs for smart meter implementation in the EE&C Plan, and that inclusion of such costs would cause the EE&C Plan to exceed the statutory cap for EE&C expenditures. The OCA also contends that WP s EE&C plan does not meet the Total Resource Cost Test. The appeal remains pending but has been stayed by the Commonwealth Court pending possible settlement of WP s SMIP. In September, 2010, WP filed an amended EE&C Plan that is less reliant on smart meter deployment, which the PPUC approved in January 2011.

Met-Ed, Penelec and Penn jointly filed a SMIP with the PPUC in August 2009. This plan proposed a 24-month assessment period in which the Pennsylvania Companies will assess their needs, select the necessary technology, secure vendors, train personnel, install and test support equipment, and establish a cost effective and strategic deployment schedule, which currently is expected to be completed in fifteen years. Met-Ed, Penelec and Penn estimate assessment period costs of approximately $29.5 million, which the Pennsylvania Companies, in their plan, proposed to recover through an automatic adjustment clause. The ALJ s Initial Decision approved the SMIP as modified by the ALJ, including: ensuring that the smart meters to be deployed include the capabilities listed in the PPUC s Implementation Order; denying the recovery of interest through the automatic adjustment clause; providing for the recovery of reasonable and prudent costs net of resulting savings from installation and use of smart meters; and requiring that administrative start-up costs be expensed and the costs incurred for research and development in the assessment period be capitalized. In April 2010, the PPUC adopted a Motion by Chairman Cawley that modified the ALJ s initial decision, and decided various issues regarding the SMIP for Met-Ed, Penelec and Penn. The PPUC entered its Order in June 2010, consistent with the Chairman s Motion. Met-Ed, Penelec and Penn filed a Petition for Reconsideration of a single portion of the PPUC s Order regarding the future ability to include smart meter costs in base rates, which the PPUC granted in part by deleting language from its original order that would have precluded Met-Ed, Penelec and Penn from seeking to include smart meter costs in base rates at a later time. The costs to implement the SMIP could be material. However, assuming these costs satisfy a just and reasonable standard, they are expected to be recovered in a rider (Smart Meter Technologies Charge Rider) which was approved when the PPUC approved the SMIP.

In August 2009, WP filed its original SMIP, which provided for extensive deployment of smart meter infrastructure with replacement of all of WP s approximately 725,000 meters by the end of 2014. In December 2009, WP filed a motion to reopen the evidentiary record to submit an alternative smart meter plan proposing, among other things, a less-rapid deployment of smart meters. In an Initial Decision dated April 29, 2010, an ALJ determined that WP s alternative smart meter deployment plan, which contemplated deployment of 375,000 smart meters by May 2012, complied with the requirements of Act 129 and recommended approval of the alternative plan, including WP s proposed cost recovery mechanism.

In light of the significant expenditures that would be associated with its smart meter deployment plans and related infrastructure upgrades, as well as its evaluation of recent PPUC decisions approving less-rapid deployment proposals by other utilities, WP re-evaluated its Act 129 compliance strategy, including both its plans with respect to smart meter deployment and certain smart meter dependent aspects of the EE&C Plan. In October 2010, WP and Pennsylvania s Office of Consumer Advocate filed a Joint Petition for Settlement addressing WP s smart meter implementation plan with the PPUC. Under the terms of the proposed settlement, WP proposed to decelerate its previously contemplated smart meter deployment schedule and to target the installation of approximately 25,000 smart meters in support of its EE&C Plan, based on customer requests, by mid-2012. The proposed settlement also contemplates that WP take advantage of the 30-month grace period authorized by the PPUC to continue WP s efforts to re-evaluate full-scale smart meter deployment plans. WP currently anticipates filing its plan for full-scale deployment of smart meters in June 2012. Under the terms of the proposed settlement, WP would be permitted to recover certain previously incurred and anticipated smart-meter related expenditures through a levelized customer surcharge, with certain expenditures amortized over a ten-year period. Additionally, WP would be permitted to seek recovery of certain other costs as part of its revised SMIP that it currently intends to file in June 2012, or in a future base distribution rate case.

In December 2010, the PPUC directed that the SMIP proceeding be referred to the ALJ for further proceedings to ensure that the impact of the proposed merger with FirstEnergy is considered and that the Joint Petition for Settlement has adequate support in the record. On March 9, 2011, WP submitted an Amended Joint Petition for Settlement which restates the Joint Petition for Settlement filed in October 2010, adds the PPUC s Office of Trial Staff as a signatory party, and confirms the support or non-opposition of all parties to the settlement. The proposed settlement also obligates OCA to withdraw its November 2009 appeal of the PPUC s Order in WP s EE&C plan proceeding. A Joint Stipulation with the OSBA was also filed on March 9, 2011. The proposed settlement remains subject to review by the ALJ, who will prepare an Initial Decision for consideration by the PPUC.

By Tentative Order entered in September 2009, the PPUC provided for an additional 30-day comment period on whether the 1998 Restructuring Settlement, which addressed how Met-Ed and Penelec were going to implement direct access to a competitive market for the generation of electricity, allows Met-Ed and Penelec to apply over-collection of NUG costs for select and isolated months to reduce non-NUG stranded costs when a cumulative NUG stranded cost balance exists. In response to the Tentative Order, various parties filed comments objecting to the above accounting method utilized by Met-Ed and Penelec. Met-Ed and Penelec are awaiting further action by the PPUC.

In the PPUC Order approving the FirstEnergy and Allegheny merger, the PPUC announced that a separate statewide investigation into Pennsylvania s retail electricity market will be conducted with the goal of making recommendations for improvements to ensure that a properly functioning and workable competitive retail electricity market exists in the state. The PPUC has not yet initiated that investigation.

(F) VIRGINIA

In September 2010, PATH-VA filed an application with the Virginia SCC for authorization to construct the Virginia portions of the PATH Project. On February 28, 2011, PATH-VA filed a motion to withdraw the application. See Transmission Expansion in the Federal Regulation and Rate Matters section for further discussion of this matter.

(G) WEST VIRGINIA

In August 2009, MP and PE filed with the WVPSC a request to increase retail rates by approximately $122.1 million annually, effective June 10, 2010. In January 2010, MP and PE filed supplemental testimony discussing a tax treatment change that would result in a revenue requirement approximately $7.7 million lower than the requirement included in the original filing. In addition, in December 2009, subsidiaries of MP and PE completed a securitization transaction to finance certain costs associated with the installation of scrubbers at the Fort Martin generating station, which costs would otherwise have been included in the request for rate recovery. Consequently, MP and PE ultimately requested an annual increase in retail rates of approximately $95 million, rather than $122.1 million. In April 2010, MP and PE filed with the WVPSC a Joint Stipulation and Agreement of Settlement reached with the other parties in the proceeding that provided for:

- a $40 million annualized base rate increase effective June 29, 2010;
- a deferral of February 2010 storm restoration expenses in West Virginia over a maximum five-year period;
- an additional $20 million annualized base rate increase effective in January 2011;
- a decrease of $20 million in ENEC rates effective January 2011, which amount is deferred for later recovery in 2012; and
- a moratorium on filing for further increases in base rates before December 1, 2011, except under specified circumstances.

The WVPSC approved the Joint Petition and Agreement of Settlement in June 2010.

In 2009, the West Virginia Legislature enacted the Alternative and Renewable Energy Portfolio Act (Portfolio Act), which generally requires that a specified minimum percentage of electricity sold to retail customers in West Virginia by electric utilities each year be derived from alternative and renewable energy resources according to a predetermined schedule of increasing percentage targets, including ten percent by 2015, fifteen percent by 2020, and twenty-five percent by 2025. In November 2010, the WVPSC issued Rules Governing Alternative and Renewable Energy Portfolio Standard (RPS Rules), which became effective on January 4, 2011. Under the RPS Rules, on or before January 1, 2011, each electric utility subject to the provisions of this rule was required to prepare an alternative and renewable energy portfolio standard compliance plan and file an application with the WVPSC seeking approval of such plan. MP and PE filed their combined compliance plan in December 2010. Additionally, in January 2011, MP and PE filed an application with the WVPSC seeking to certify three facilities as Qualified Energy Resource Facilities. If the application is approved, the three facilities would then be capable of generating renewable credits which would assist the companies in meeting their combined requirements under the Portfolio Act. Further, in February 2011, MP and PE filed a petition with the WVPSC seeking an Order declaring that MP is entitled to all alternative & renewable energy resource credits associated with the electric energy, or energy and capacity, that MP is required to purchase pursuant to electric energy purchase agreements between MP and three non-utility electric generating facilities in WV. The City of New Martinsville, the owner of one of the contracted resources, has filed an opposition to the Petition.

(H) FERC MATTERS

Rates for Transmission Service Between MISO and PJM

In November 2004, the FERC issued an order eliminating the through and out rate for transmission service between the MISO and PJM regions. The FERC s intent was to eliminate multiple transmission charges for a single transaction between the MISO and PJM regions. The FERC also ordered MISO, PJM and the transmission owners within MISO and PJM to submit compliance filings containing a rate mechanism to recover lost transmission revenues created by elimination of this charge (referred to as SECA) during a 16-month transition period. In 2005, the FERC set the SECA for hearing. The presiding ALJ issued an initial decision in August 2006, rejecting the compliance filings made by MISO, PJM and the transmission owners, and directing new compliance filings. This decision was subject to review and approval by the FERC. In May 2010, FERC issued an order denying pending rehearing requests and an Order on Initial Decision which reversed the presiding ALJ s rulings in many respects. Most notably, these orders affirmed the right of transmission owners to collect SECA charges with adjustments that modestly reduce the level of such charges, and changes to the entities deemed responsible for payment of the SECA charges. The Ohio Companies were identified as load serving entities responsible for payment of additional SECA charges for a portion of the SECA period (Green Mountain/Quest issue). FirstEnergy executed settlements with AEP, Dayton and the Exelon parties to fix FirstEnergy s liability for SECA charges originally billed to Green Mountain and Quest for load that returned to regulated service during the SECA period. The AEP, Dayton and Exelon, settlements were approved by the FERC in November 2010, and the relevant payments made. The Utilities have refund obligations that are under review by FERC as part of a compliance filing. Potential refund obligations of FirstEnergy are not expected to be material. Rehearings remain pending in this proceeding.

PJM Transmission Rate

In April 2007, FERC issued an order (Opinion 494) finding that the PJM transmission owners existing license plate or zonal rate design was just and reasonable and ordered that the current license plate rates for existing transmission facilities be retained. On the issue of rates for new transmission facilities, FERC directed that costs for new transmission facilities that are rated at 500 kV or higher are to be collected from all transmission zones throughout the PJM footprint by means of a postage-stamp rate based on the amount of load served in a transmission zone. Costs for new transmission facilities that are rated at less than 500 kV, however, are to be allocated on a load flow methodology (DFAX), which is generally referred to as a beneficiary pays approach to allocating the cost of high voltage transmission facilities.

The FERC s Opinion 494 order was appealed to the U.S. Court of Appeals for the Seventh Circuit, which issued a decision in August 2009. The court affirmed FERC s ratemaking treatment for existing transmission facilities, but found that FERC had not supported its decision to allocate costs for new 500+ kV facilities on a load ratio share basis and, based on this finding, remanded the rate design issue back to FERC.

In an order dated January 21, 2010, FERC set the matter for paper hearings meaning that FERC called for parties to submit comments or written testimony pursuant to the schedule described in the order. FERC identified nine separate issues for comments and directed PJM to file the first round of comments on February 22, 2010, with other parties submitting responsive comments and then reply comments on later dates. PJM filed certain studies with FERC on April 13, 2010, in response to the FERC order. PJM s filing demonstrated that allocation of the cost of high voltage transmission facilities on a beneficiary pays basis results in certain eastern utilities in PJM bearing the majority of the costs. Numerous parties filed responsive comments or studies on May 28, 2010 and reply comments on June 28, 2010. FirstEnergy and a number of other utilities, industrial customers and state commissions supported the use of the beneficiary pays approach for cost allocation for high voltage transmission facilities. Certain eastern utilities and their state commissions supported continued socialization of these costs on a load ratio share basis. This matter is awaiting action by the FERC.

RTO Realignment

On February 1, 2011, ATSI in conjunction with PJM filed its proposal with FERC for moving its transmission rate into PJM s tariffs. FirstEnergy expects ATSI to enter PJM on June 1, 2011, and that if legal proceedings regarding its rate are outstanding at that time, ATSI will be permitted to start charging its proposed rates, subject to refund. On April 1, 2011, the MISO Transmission Owners (including ATSI) filed proposed tariff language that describes the

mechanics of collecting and administering MTEP costs from ATSI-zone ratepayers. From March 20, 2011 through April 1, 2011, FirstEnergy, PJM and the MISO submitted numerous filings for the purpose of effecting movement of the ATSI zone to PJM on June 1, 2011. These filings include clean-up of the MISO s tariffs (to remove the ATSI zone), submission of load and generation interconnection agreements to reflect the move into PJM, and submission of changes to PJM s tariffs to support the move into PJM.
FERC proceedings are pending in which ATSI s transmission rate, the exit fee payable to MISO, transmission cost allocations and costs associated with long term firm transmission rights payable by the ATSI zone upon its departure from the MISO are under review. The outcome of these proceedings cannot be predicted.

MISO Multi-Value Project Rule Proposal

In July 2010, MISO and certain MISO transmission owners jointly filed with FERC their proposed cost allocation methodology for certain new transmission projects. The new transmission projects described as MVPs are a class of MTEP projects. The filing parties proposed to allocate the costs of MVPs by means of a usage-based charge that will be applied to all loads within the MISO footprint, and to energy transactions that call for power to be wheeled through the MISO as well as to energy transactions that source in the MISO but sink outside of MISO. The filing parties expect that the MVP proposal will fund the costs of large transmission projects designed to bring wind generation from the upper Midwest to load centers in the east. The filing parties requested an effective date for the proposal of July 16, 2011. On August 19, 2010, MISO s Board approved the first MVP project the Michigan Thumb Project. Under MISO s proposal, the costs of MVP projects approved by MISO s Board prior to the anticipated June 1, 2011 effective date of FirstEnergy s integration into PJM would continue to be allocated to FirstEnergy. MISO estimated that approximately $15 million in annual revenue requirements would be allocated to the ATSI zone associated with the Michigan Thumb Project upon its completion.

In September 2010, FirstEnergy filed a protest to the MVP proposal arguing that MISO s proposal to allocate costs of MVP projects across the entire MISO footprint does not align with the established rule that cost allocation is to be based on cost causation (the beneficiary pays approach). FirstEnergy also argued that, in light of progress to date in the ATSI integration into PJM, it would be unjust and unreasonable to allocate any MVP costs to the ATSI zone, or to ATSI. Numerous other parties filed pleadings on MISO s MVP proposal.

In December 2010, FERC issued an order approving the MVP proposal without significant change. FERC s order was not clear, however, as to whether the MVP costs would be payable by ATSI or load in the ATSI zone. FERC stated that the MISO s tariffs obligate ATSI to pay all charges that attach prior to ATSI s exit but ruled that the question of the amount of costs that are to be allocated to ATSI or to load in the ATSI zone were beyond the scope of FERC s order and would be addressed in future proceedings.

On January 18, 2011, FirstEnergy filed for rehearing of FERC s order. In its rehearing request, FirstEnergy argued that because the MVP rate is usage-based, costs could not be applied to ATSI, which is a stand-alone transmission company that does not use the transmission system. FirstEnergy also renewed its arguments regarding cost causation and the impropriety of allocating costs to the ATSI zone or to ATSI. FirstEnergy cannot predict the outcome of these proceedings at this time.

PJM Calculation Error

In March 2010, MISO filed two complaints at FERC against PJM relating to a previously-reported modeling error in PJM s system that impacted the manner in which market-to-market power flow calculations were made between PJM and MISO since April 2005. MISO claimed that this error resulted in PJM underpaying MISO by approximately $130 million over the time period in question. Additionally, MISO alleged that PJM did not properly trigger market-to-market settlements between PJM and MISO during times when it was required to do so, which MISO claimed may have cost it $5 million or more. As PJM market participants, AE Supply and MP may be liable for a portion of any refunds ordered in this case. PJM, Allegheny and other PJM market participants filed responses to MISO complaints and PJM filed a related complaint at FERC against MISO claiming that MISO improperly called for market-to-market settlements several times during the same time period covered by the two MISO complaints filed against PJM, which PJM claimed may have cost PJM market participants $25 million or more. On January 4, 2011, an Offer of Settlement was filed at FERC that, if approved, would resolve all pending issues in the dispute. The Offer of Settlement calls for the withdrawal of all pending complaints with no payments being made by any parties. Initial comments on the Offer of Settlement were filed at FERC on January 24, 2011. FirstEnergy and Allegheny Energy filed comments supporting the proposed settlement. A report on the partially contested settlement was issued by the settlement judge to the FERC on March 9, 2011. On March 16, 2011, the settlement judge terminated the settlement proceedings and forwarded the partially contested settlement to the FERC for review. The case is awaiting a decision by the FERC.

California Claims Matters

In October 2006, several California governmental and utility parties presented AE Supply with a settlement proposal to resolve alleged overcharges for power sales by AE Supply to the California Energy Resource Scheduling division of the California Department of Water Resources (CDWR) during 2001. The settlement proposal claims that CDWR is owed approximately $190 million for these alleged overcharges. This proposal was made in the context of mediation efforts by the FERC and the United States Court of Appeals for the Ninth Circuit in pending proceedings to resolve all outstanding refund and other claims, including claims of alleged price manipulation in the California energy markets during 2000 and 2001. The Ninth Circuit has since remanded one of those proceedings to the FERC, which arises out of claims previously filed with the FERC by the California Attorney General on behalf of certain California parties against various sellers in the California wholesale power market, including AE Supply (the Lockyer case). AE Supply and several other sellers have filed motions to dismiss the Lockyer case. In March 2010, the judge assigned to the case entered an opinion that granted the motions to dismiss filed by AE Supply and other sellers and dismissed the claims of the California Parties. In April 2010, the California parties filed exceptions to the judge s ruling with the FERC, and briefing is complete on those exceptions. The parties are awaiting a ruling from the FERC on the exceptions.

In June 2009, the California Attorney General, on behalf of certain California parties, filed a second lawsuit with the FERC against various sellers, including AE Supply (the Brown case), again seeking refunds for trades in the California energy markets during 2000 and 2001. The above-noted trades with CDWR are the basis for the joining of AE Supply in this new lawsuit. AE Supply has filed a motion to dismiss the Brown case that is pending before the FERC. No scheduling order has been entered in the Brown case. Allegheny intends to vigorously defend against these claims but cannot predict their outcome.

Transmission Expansion

TrAIL Project. TrAIL is a 500kV transmission line currently under construction that will extend from southwest Pennsylvania through West Virginia and into northern Virginia. On April 15, 2011, the TrAIL 500 kV line segment from Meadowbrook substation to Loudoun substation in Virginia was successfully energized and is carrying load. The other segments are planned to be energized in May. The entire TrAIL line is scheduled to be completed and placed in service no later than June 2011.

PATH Project. The PATH Project is comprised of a 765 kV transmission line that is proposed to extend from West Virginia through Virginia and into Maryland, modifications to an existing substation in Putnam County, West Virginia, and the construction of new substations in Hardy County, West Virginia and Frederick County, Maryland.

PJM initially authorized construction of the PATH Project in June 2007 and, on June 17, 2010, requested that PATH, LLC proceed with all efforts related to the PATH Project, including state regulatory proceedings, assuming a required in-service date of June 1, 2015. In December 2010, PJM advised that its 2011 Load Forecast Report included load projections that are different from previous forecasts and that may have an impact on the proposed in-service date for the PATH Project. As part of its 2011 RTEP, and in response to a January 19, 2011 directive by a Virginia Hearing Examiner, PJM conducted a series of analyses using the most current economic forecasts and demand response commitments, as well as potential new generation resources. Preliminary analysis revealed the expected reliability violations that necessitated the PATH Project had moved several years into the future. Based on those results, PJM announced on February 28, 2011 that its Board of Managers had decided to hold the PATH Project in abeyance in its 2011 RTEP and directed FirstEnergy and AEP, as the sponsoring transmission owners, to suspend current development efforts on the project, subject to those activities necessary to maintain the project in its current state, while PJM conducts more rigorous analysis of the potential need for the project as part of its continuing RTEP process. PJM stated that its action did not constitute a directive to FirstEnergy and AEP to cancel or abandon the PATH Project. PJM further stated that it will complete a more rigorous analysis of the PATH Project and other transmission requirements and its Board will review this comprehensive analysis as part of its consideration of the 2011 RTEP. On February 28, 2011, affiliates of FirstEnergy and AEP filed motions or notices to withdraw applications for authorization to construct the project that were pending before state commissions in West Virginia, Virginia and Maryland. Withdrawal was deemed effective upon filing the notice with the MDPSC and the WVPSC has granted the motion to withdraw. The VSCC has not ruled on the motion to withdraw.

PATH, LLC submitted a filing to FERC to implement a formula rate tariff effective March 1, 2008. In a November 19, 2010 order addressing various matters relating to the formula rate, FERC set the project s base return on equity for hearing and reaffirmed its prior authorization of a return on CWIP, recovery of start-up costs and recovery of abandonment costs. In the order, FERC also granted a 1.5% return on equity incentive adder and a 0.50% return on equity adder for RTO participation. These adders will be applied to the base return on equity determined as a result of the hearing. PATH, LLC is currently engaged in settlement discussions with the staff of FERC and intervenors regarding resolution of the base return on equity. FirstEnergy cannot predict the outcome of this proceeding or whether it will have a material impact on its operating results.

Sales to Affiliates

FES has received authorization from the FERC to make wholesale power sales to affiliated regulated utilities in New Jersey, Ohio, and Pennsylvania. FES actively participates in auctions conducted by or on behalf the regulated affiliates to obtain power necessary to meet the utilities POLR obligations. AE Supply, a merchant affiliate acquired in the FirstEnergy-Allegheny merger, also participates in these auctions, and obtains prior FERC authorization when necessary to make sales to FE affiliates.

11. STOCK-BASED COMPENSATION PLANS

FirstEnergy has four types of stock-based compensation programs including LTIP, EDCP, ESOP and DCPD, as described below.

In addition, Allegheny s stock-based awards were converted into First Energy stock-based awards as of the date of the merger. These awards, referred to below as converted Allegheny awards, were adjusted in terms of the number of awards and where applicable, the exercise price thereof, to reflect the merger s common stock exchange ratio of 0.667 of a share of FirstEnergy common stock for each share of Allegheny common stock.

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(A) LTIP

FirstEnergy s LTIP includes four forms of stock-based compensation awards stock options, performance shares, restricted stock and restricted stock units.

Under FirstEnergy s LTIP, total awards cannot exceed 29.1 million shares of common stock or their equivalent. Only stock options, restricted stock and restricted stock units have currently been designated to be settled in common stock, with vesting periods ranging from two months to ten years. Performance share awards are currently designated to be paid in cash rather than common stock and therefore do not count against the limit on stock-based awards. There were 6.3 million shares available for future awards as of March 31, 2011.

Restricted Stock and Restricted Stock Units

Restricted common stock (restricted stock) and restricted stock unit (stock unit) activity was as follows:

	Three Months Ended March 31, 2011
Restricted stock and stock units outstanding as of January 1, 2011	1,878,022
Granted	223,161
Converted Allegheny restricted stock	645,197
Exercised	(422,031)
Forfeited	(37,182)
Restricted stock and stock units outstanding as of March 31, 2011	2,287,167

The 223,161 shares of restricted common stock granted during the three months ended March 31, 2011 had a grant-date fair value of $8.2 million and a weighted-average vesting period of 1.86 years.

Restricted stock units include awards that will be settled in a specific number of shares of stock after the service condition has been met. Restricted stock units also include performance-based awards that will be settled after the service condition has been met in a specified number of shares of stock based on FirstEnergy s performance compared to annual target performance metrics.

Compensation expense recognized for the three months ended March 31, 2011 and 2010 for restricted stock and restricted stock units, net of amounts capitalized, was approximately $16 million and $6 million, respectively.

Stock Options

Stock option activity for the three months ended March 31, 2011 was as follows:

Stock Option Activities	**Number of Shares**	**Weighted Average Exercise Price**
Stock options outstanding as of January 1, 2011 (all exercisable)	2,889,066	$ 35.18
Options granted	662,122	37.75
Converted Allegheny options	1,805,811	41.75
Options exercised	(182,422)	29.56
Options forfeited/expired	(6,670)	69.36
Stock options outstanding as of March 31, 2011	5,167,907	$ 37.96

(4,505,785 options exercisable)

Compensation expense recognized for stock options during the three months ended March 31, 2011 was $0.1 million. No expense was recognized during the three months ending March 31, 2010. Options granted during the three months ended March 31, 2011 had a grant-date fair value of $3.3 million and an expected weighted-average vesting period of 3.79 years.

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Options outstanding by exercise price as of March 31, 2011 were as follows:

Exercise Prices		Shares Under Options		Weighted Average Exercise Price	Remaining Contractual Life in Years
$20.02	$30.74	1,305,563	$	26.72	2.01
$30.89	$40.93	3,378,866		37.22	4.79
$42.72	$51.82	37,233		44.40	0.24
$53.06	$62.97	54,559		56.15	3.27
$64.52	$71.82	54,778		68.52	1.09
$73.39	$80.47	327,570		80.19	6.01
$81.19	$89.59	9,338		83.51	1.92
Total		5,167,907	$	37.96	4.07

Performance Shares

Performance shares will be settled in cash and are accounted for as liability awards. Compensation expense (income) recognized for performance shares during the three months ended March 31, 2011 and 2010, net of amounts capitalized, totaled $1 million and $(3) million, respectively. No performance shares under the FirstEnergy LTIP were settled during the three months ended March 31, 2011 and 2010.

(B) ESOP

During 2011 shares of FirstEnergy common stock were purchased on the open market and contributed to participants accounts. Total ESOP-related compensation expense for the three months ended March 31, 2011 and 2010, net of amounts capitalized and dividends on common stock were $7 million and $5 million, respectively.

(C) EDCP

Compensation expense (income) recognized on EDCP stock units, for the three months ended March 31, 2011 and 2010, net of amounts capitalized, was not material.

(D) DCPD

DCPD expenses recognized for the three months ended March 31, 2011 and 2010 were approximately $1 million and $1 million. The net liability recognized for DCPD of approximately $5 million as of March 31, 2011 is included in the caption Retirement benefits on the Consolidated Balance Sheets.

Of the 1.7 million stock units authorized under the EDCP and DCPD, 1,076,779 stock units were available for future awards as of March 31, 2011.

12. NEW ACCOUNTING STANDARDS AND INTERPRETATIONS

During the three months ended March 31, 2011, there were no new accounting standards or interpretations issued, but not effective that would materially affect FirstEnergy s financial statements.

13. SEGMENT INFORMATION

With the completion of the Allegheny merger in the first quarter of 2011, FirstEnergy reorganized its management structure, which resulted in changes to its operating segments to be consistent with the manner in which management views the business. The new structure supports the combined company s primary operations distribution, transmission, generation and the marketing and sale of its products. The external segment reporting is consistent with the internal financial reporting utilized by FirstEnergy s chief executive officer (its chief operating decision maker) to regularly assess the performance of the business and allocate resources. FirstEnergy now has three reportable operating segments Regulated Distribution, Regulated Independent Transmission and Competitive Energy Services.

Prior to the change in composition of business segments, FirstEnergy s business was comprised of two reportable operating segments. The Energy Delivery Services segment included FirstEnergy s then eight existing utility operating companies that transmit and distribute electricity to customers and purchase power to serve their POLR and default service requirements. The Competitive Energy Services segment was comprised of FES, which supplies electric power to end-use customers through retail and wholesale arrangements. The Other segment consisted of corporate items and other businesses that were below the quantifiable threshold for separate disclosure. Disclosures for FirstEnergy s operating segments for 2010 have been reclassified to conform to the current presentation.

The changes in FirstEnergy s reportable segments during the first quarter of 2011 consisted primarily of the following:

Energy Delivery Services was renamed Regulated Distribution and the operations of MP, PE and WP, which were acquired as part of the merger with Allegheny, and certain regulatory asset recovery mechanisms formerly included in the Other segment, were placed into this segment.

A new Regulated Independent Transmission segment was created consisting of ATSI, and the operations of TrAIL Company and FirstEnergy s interest in PATH; TrAIL and PATH were acquired as part of the merger with Allegheny. The transmission assets and operations of JCP&L, Met-Ed, Penelec, MP, PE and WP remain within the Regulated Distribution segment.

AE Supply, an operator of generation facilities that was acquired as part of the merger with Allegheny, was placed into the Competitive Energy Services segment.

Financial information for each of FirstEnergy s reportable segments is presented in the table below, which includes financial results for Allegheny beginning February 25, 2011. FES and the Utilities do not have separate reportable operating segments.

The Regulated Distribution segment distributes electricity through FirstEnergy s ten utility operating companies, serving approximately 6 million customers within 67,000 square miles of Ohio, Pennsylvania, West Virginia, Virginia, Maryland, New Jersey and New York, and purchases power for its POLR and default service requirements in Ohio, Pennsylvania and New Jersey. This segment also includes the transmission operations of JCP&L, Met-Ed, Penelec, WP, MP and PE and the regulated electric generation facilities in West Virginia and New Jersey which MP and JCP&L, respectively, own or contractually control.

The Regulated Distribution segment s revenues are primarily derived from the delivery of electricity within FirstEnergy s service areas, cost recovery of regulatory assets and the sale of electric generation service to retail customers who have not selected an alternative supplier (POLR or default service) in its Maryland, New Jersey, Ohio and Pennsylvania franchise areas. Its results reflect the commodity costs of securing electric generation from FES and AE Supply and from non-affiliated power suppliers and the deferral and amortization of certain fuel costs.

The Regulated Independent Transmission segment transmits electricity through transmission lines and its revenues are primarily derived from the formula rate recovery of costs and a return on debt and equity for capital expenditures in connection with TrAIL, PATH and other projects and revenues from providing transmission services to electric energy providers, power marketers and receiving transmission-related revenues from operation of a portion of the FirstEnergy transmission system. Its results reflect the net PJM and MISO transmission expenses related to the delivery of the respective generation loads. On June 1, 2011, the ATSI transmission assets currently dedicated to MISO are scheduled to be integrated into the PJM market. This integration brings all of FirstEnergy s assets into one RTO.

The Competitive Energy Services segment, through FES, supplies electric power to end-use customers through retail and wholesale arrangements, including associated company power sales to meet all or a portion of the POLR and default service requirements of FirstEnergy s Ohio and Pennsylvania utility subsidiaries and competitive retail sales to customers primarily in Ohio, Pennsylvania, Illinois, Maryland, Michigan and New Jersey. FES purchases the entire output of the 18 generating facilities which it owns and operates through its FGCO subsidiary (fossil and hydroelectric generating facilities) and owns, through its NGC subsidiary, FirstEnergy s nuclear generating facilities. FENOC, a separate subsidiary of FirstEnergy, operates and maintains NGC s nuclear generating facilities as well as the output relating to leasehold interests of OE and TE in certain of those facilities that are subject to sale and leaseback arrangements with non-affiliates, pursuant to full output, cost-of-service PSAs.

The Competitive Energy Services segment also includes Allegheny s unregulated electric generation operations, including AE Supply and AE Supply s interest in AGC. AE Supply owns, operates and controls the electric generation capacity of its 18 facilities. AGC owns and sells generation capacity to AE Supply and MP, which own approximately 59% and 41% of AGC, respectively. AGC s sole asset is a 40% undivided interest in the Bath County, Virginia pumped-storage hydroelectric generation facility and its connecting transmission facilities. All of AGC s revenues are derived from sales of its 1,109 MW share of generation capacity from the Bath County generation facility to AE Supply and MP.

This business segment controls approximately 20,000 MWs of capacity and also purchases electricity to meet sales obligations. The segment s net income is primarily derived from affiliated and non-affiliated electric generation sales less the related costs of electricity generation, including purchased power and net transmission (including congestion) and ancillary costs charged by PJM and MISO to deliver energy to the segment s customers.

The Other segment contains corporate items and other businesses that are below the quantifiable threshold for separate disclosure as a reportable segment.

Segment Financial Information

Three Months Ended	Regulated Distribution	Competitive Energy Services	Regulated Independent Transmission	Other/ Corporate	Reconciling Adjustments	Consolidated
			(In millions)			
March 31, 2011						
External revenues	$ 2,268	$ 1,254	$ 67	$ (23)	$ (22)	$ 3,544
Internal revenues		343			(311)	32
Total revenues	2,268	1,597	67	(23)	(333)	3,576
Depreciation and amortization	245	88	13	6		352
Investment income (loss), net	25	6			(10)	21
Net interest charges	131	68	9	19	(14)	213
Income taxes	56	3	7	(20)	32	78
Net income (loss)	96	5	13	(35)	(34)	45
Total assets	27,165	17,308	2,479	914		47,866
Total goodwill	5,551	976				6,527
Property additions	177	214	27	31		449
March 31, 2010						
External revenues	$ 2,484	$ 719	$ 57	$ (22)	$ (6)	$ 3,232
Internal revenues		674			(607)	67
Total revenues	2,484	1,393	57	(22)	(613)	3,299
Depreciation and amortization	313	77	12	3		405
Investment income (loss), net	26	1		1	(12)	16
Net interest charges	124	33	5	13	(3)	172
Income taxes	62	42	7	(12)	12	111
Net income (loss)	103	69	12	(19)	(16)	149
Total assets	21,535	10,950	995	598		34,078
Total goodwill	5,551	24				5,575
Property additions	152	329	14	13		508

Reconciling adjustments to segment operating results from internal management reporting to consolidated external financial reporting primarily consist of elimination of intersegment transactions.

14. IMPAIRMENT OF LONG-LIVED ASSETS

FirstEnergy reviews long-lived assets for impairment whenever events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. The recoverability of a long-lived asset is measured by comparing its carrying value to the sum of undiscounted future cash flows expected to result from the use and eventual disposition of the asset. If the carrying value is greater than the undiscounted cash flows, impairment exists and a loss is recognized for the amount by which the carrying value of the long-lived asset exceeds its estimated fair value. Two events occurred during the first quarter of 2011 that indicated the carrying value of certain assets may not be recoverable as described in the sections below.

Fremont Energy Center

On March 11, 2011, FirstEnergy and American Municipal Power, Inc., (AMP) entered into an agreement for the sale of Fremont Energy Center, which includes two natural gas combined-cycle combustion turbines and a steam turbine capable of producing 544 MW of load-following capacity and 163 MW of peaking capacity. The agreement provides, among other things, for a targeted closing date in July 2011. The execution of this agreement triggered a need to evaluate the recoverability of the carrying value of the assets associated with the Fremont Energy Center. The estimated fair value of the Fremont Energy Center was based on the purchase price outlined in the sale agreement with American Municipal Power, Inc. The result of this evaluation indicated that the carrying cost of the Fremont Energy Center was not fully recoverable. As a result of the recoverability evaluation, FirstEnergy recorded an impairment charge of $11 million to operating income during the quarter ended March 31, 2011. On April 19, 2011, FGCO filed an section 203 application with the FERC for authorization to sell the Fremont Energy Center, including related capacity supply obligations, to AMP. Comments are due on the filing on or before May 10, 2011. FGCO requested FERC action by June 17, 2011.

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Peaking Facilities

During the three months ended March 31, 2011, FirstEnergy assessed the carrying values of certain peaking facilities that will more likely than not be sold or disposed of before the end of their useful lives. The estimated fair values were based on estimated sales prices quoted in an active market. The result of this evaluation indicated that the carrying costs of the peaking facilities were not fully recoverable. As a result of the recoverability evaluation, FirstEnergy recorded an impairment charge of $14 million to the operating income of its Competitive Energy Services segment during the quarter ended March 31, 2011.

15. ASSET RETIREMENT OBLIGATIONS

FirstEnergy has recognized applicable legal obligations for AROs and their associated cost for nuclear power plant decommissioning, reclamation of sludge disposal ponds and closure of coal ash disposal sites. In addition, FirstEnergy has recognized conditional asset retirement obligations (primarily for asbestos remediation).

The ARO liabilities for FES and OE include the decommissioning of the Perry nuclear generating facilities. FES and OE use an expected cash flow approach to measure the fair value of their nuclear decommissioning AROs.

During the first quarter of 2011, studies were completed to update the estimated cost of decommissioning the Perry nuclear generating facility. The cost studies resulted in a revision to the estimated cash flows associated with the ARO liabilities of FES and OE and reduced the liability for each subsidiary in the amounts of $40 million and $6 million, respectively, as of March 31, 2011.

The revision to the estimated cash flows had no significant impact on accretion of the obligation during the first quarter of 2011 when compared to the first quarter of 2010.

16. SUPPLEMENTAL GUARANTOR INFORMATION

On July 13, 2007, FGCO completed a sale and leaseback transaction for its 93.825% undivided interest in Bruce Mansfield Unit 1. FES has fully, unconditionally and irrevocably guaranteed all of FGCO s obligations under each of the leases. The related lessor notes and pass through certificates are not guaranteed by FES or FGCO, but the notes are secured by, among other things, each lessor trust s undivided interest in Unit 1, rights and interests under the applicable lease and rights and interests under other related agreements, including FES lease guaranty. This transaction is classified as an operating lease under GAAP for FES and FirstEnergy and as a financing for FGCO.

The condensed consolidating statements of income for the three month periods ended March 31, 2011 and 2010, consolidating balance sheets as of March 31, 2011 and December 31, 2010 and consolidating statements of cash flows for the three months ended March 31, 2011 and 2010 for FES (parent and guarantor), FGCO and NGC (non-guarantor) are presented below. Investments in wholly owned subsidiaries are accounted for by FES using the equity method. Results of operations for FGCO and NGC are, therefore, reflected in FES investment accounts and earnings as if operating lease treatment was achieved. The principal elimination entries eliminate investments in subsidiaries and intercompany balances and transactions and the entries required to reflect operating lease treatment associated with the 2007 Bruce Mansfield Unit 1 sale and leaseback transaction.

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FIRSTENERGY SOLUTIONS CORP.
CONDENSED CONSOLIDATING STATEMENTS OF INCOME
(Unaudited)

For the Three Months Ended March 31, 2011	FES	FGCO	NGC	Eliminations	Consolidated
			(In thousands)		
REVENUES	$ 1,366,899	$ 742,638	$ 467,967	$ (1,186,416)	$ 1,391,088
EXPENSES:					
Fuel	1,203	293,862	48,044		343,109
Purchased power from affiliates	1,184,606	1,772	68,743	(1,186,378)	68,743
Purchased power from non-affiliates	296,733	205			296,938
Other operating expenses	177,529	118,245	188,009	12,152	495,935
Provision for depreciation	879	31,539	37,333	(1,299)	68,452
General taxes	12,263	9,453	7,389		29,105
Impairment of long-lived assets		13,800			13,800
Total expenses	1,673,213	468,876	349,518	(1,175,525)	1,316,082
OPERATING INCOME (LOSS)	(306,314)	273,762	118,449	(10,891)	75,006
OTHER INCOME (EXPENSE):					
Investment income	676	232	4,953		5,861
Miscellaneous income, including net income from equity investees	247,859	584		(229,202)	19,241
Interest expense affiliates	(50)	(451)	(516)		(1,017)
Interest expense other	(24,133)	(27,758)	(16,836)	15,767	(52,960)
Capitalized interest	131	4,826	4,962		9,919
Total other income (expense)	224,483	(22,567)	(7,437)	(213,435)	(18,956)
INCOME (LOSS) BEFORE INCOME TAXES	(81,831)	251,195	111,012	(224,326)	56,050
INCOME TAXES (BENEFITS)	(117,841)	93,129	42,374	2,454	20,116
NET INCOME	36,010	158,066	68,638	(226,780)	35,934
Loss attributable to noncontrolling interest		(76)			(76)
EARNINGS AVAILABLE TO PARENT	$ 36,010	$ 158,142	$ 68,638	$ (226,780)	$ 36,010

FIRSTENERGY SOLUTIONS CORP.
CONDENSED CONSOLIDATING STATEMENTS OF INCOME
(Unaudited)

For the Three Months Ended March 31, 2010	FES	FGCO	NGC	Eliminations	Consolidated
			(In thousands)		
REVENUES	$ 1,367,025	$ 568,364	$ 426,320	$ (973,616)	$ 1,388,093
EXPENSES:					
Fuel	5,097	280,863	42,261		328,221
Purchased power from affiliates	968,537	5,079	60,953	(973,616)	60,953
Purchased power from non-affiliates	450,216				450,216
Other operating expenses	53,125	99,776	139,420	12,189	304,510
Provision for depreciation	790	26,527	36,910	(1,309)	62,918
General taxes	5,498	14,600	6,648		26,746
Impairment of long-lived assets		1,833			1,833
Total expenses	1,483,263	428,678	286,192	(962,736)	1,235,397
OPERATING INCOME (LOSS)	(116,238)	139,686	140,128	(10,880)	152,696
OTHER INCOME (EXPENSE):					
Investment income (loss)	1,897	54	(1,234)		717
Miscellaneous income (expense), including net income from equity investees	166,373	200	(101)	(163,329)	3,143
Interest expense affiliates	(58)	(1,812)	(435)		(2,305)
Interest expense other	(23,373)	(26,506)	(15,763)	15,998	(49,644)
Capitalized interest	100	16,333	3,257		19,690
Total other income (expense)	144,939	(11,731)	(14,276)	(147,331)	(28,399)
INCOME BEFORE INCOME TAXES	28,701	127,955	125,852	(158,211)	124,297
INCOME TAXES (BENEFITS)	(51,225)	48,043	45,013	2,540	44,371
NET INCOME	$ 79,926	$ 79,912	$ 80,839	$ (160,751)	$ 79,926

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FIRSTENERGY SOLUTIONS CORP.
CONDENSED CONSOLIDATING BALANCE SHEETS
(Unaudited)

As of March 31, 2011	FES	FGCO	NGC	Eliminations	Consolidated
			(In thousands)		
ASSETS					
CURRENT ASSETS:					
Cash and cash equivalents	$	$ 6,831	$ 8	$	$ 6,839
Receivables-					
Customers	388,951				388,951
Associated companies	621,241	500,097	269,750	(857,808)	533,280
Other	27,966	7,617	51,128		86,711
Notes receivable from associated companies	5,742	389,312	83,364		478,418
Materials and supplies, at average cost	46,747	251,190	191,060		488,997
Derivatives	328,156				328,156
Prepayments and other	41,403	9,093	948	(506)	50,938
	1,460,206	1,164,140	596,258	(858,314)	2,362,290
PROPERTY, PLANT AND EQUIPMENT:					
In service	99,899	6,102,623	5,421,719	(384,676)	11,239,565
Less Accumulated provision for depreciation	17,918	2,035,726	2,230,588	(176,690)	4,107,542
	81,981	4,066,897	3,191,131	(207,986)	7,132,023
Construction work in progress	8,139	147,546	600,620		756,305
Property, plant and equipment held for sale, net		476,602			476,602
	90,120	4,691,045	3,791,751	(207,986)	8,364,930
INVESTMENTS:					
Nuclear plant decommissioning trusts			1,159,903		1,159,903
Investment in associated companies	5,175,787			(5,175,787)	
Other	371	9,171	202		9,744
	5,176,158	9,171	1,160,105	(5,175,787)	1,169,647
DEFERRED CHARGES AND OTHER ASSETS:					
Accumulated deferred income tax benefits	32,544	376,182		(408,726)	
Customer intangibles	131,870				131,870
Goodwill	24,248				24,248

Property taxes		16,463	24,649		41,112
Unamortized sale and leaseback costs		23,288		67,515	90,803
Derivatives	211,223				211,223
Other	26,661	75,647	8,157	(57,408)	53,057
	426,546	491,580	32,806	(398,619)	552,313
	$ 7,153,030	$ 6,355,936	$ 5,580,920	$ (6,640,706)	$ 12,449,180
LIABILITIES AND CAPITALIZATION					
CURRENT LIABILITIES:					
Currently payable long-term debt	$ 785	$ 373,550	$ 632,106	$ (19,578)	$ 986,863
Short-term borrowings-					
Associated companies	321,133	39,410			360,543
Other		661			661
Accounts payable-					
Associated companies	769,133	290,902	208,889	(768,988)	499,936
Other	92,874	96,270			189,144
Accrued taxes	2,721	98,597	65,919	(100,744)	66,493
Derivatives	380,744				380,744
Other	31,698	119,402	26,282	47,143	224,525
	1,599,088	1,018,792	933,196	(842,167)	2,708,909
CAPITALIZATION:					
Common stockholder s equity	3,824,540	2,673,372	2,487,105	(5,160,461)	3,824,556
Long-term debt and other long-term obligations	1,488,455	2,113,043	793,250	(1,249,751)	3,144,997
	5,312,995	4,786,415	3,280,355	(6,410,212)	6,969,553
NONCURRENT LIABILITIES:					
Deferred gain on sale and leaseback transaction				950,726	950,726
Accumulated deferred income taxes			456,556	(339,053)	117,503
Accumulated deferred investment tax credits		32,511	20,670		53,181
Asset retirement obligations		27,114	839,529		866,643
Retirement benefits	48,818	240,467			289,285
Property taxes		16,463	24,649		41,112
Lease market valuation liability		205,366			205,366
Derivatives	168,409				168,409
Other	23,720	28,808	25,965		78,493
	240,947	550,729	1,367,369	611,673	2,770,718

$ 7,153,030	$ 6,355,936	$ 5,580,920	$ (6,640,706)	$ 12,449,180

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FIRSTENERGY SOLUTIONS CORP.
CONDENSED CONSOLIDATING BALANCE SHEETS
(Unaudited)

As of December 31, 2010	FES	FGCO	NGC	Eliminations	Consolidated
			(In thousands)		
ASSETS					
CURRENT ASSETS:					
Cash and cash equivalents	$	$ 9,273	$ 8	$	$ 9,281
Receivables-					
Customers	365,758				365,758
Associated companies	333,323	356,564	125,716	(338,038)	477,565
Other	21,010	55,758	12,782		89,550
Notes receivable from associated companies	34,331	188,796	173,643		396,770
Materials and supplies, at average cost	40,713	276,149	228,480		545,342
Derivatives	181,660				181,660
Prepayments and other	47,712	11,352	1,107		60,171
	1,024,507	897,892	541,736	(338,038)	2,126,097
PROPERTY, PLANT AND EQUIPMENT:					
In service	96,371	6,197,776	5,411,852	(384,681)	11,321,318
Less Accumulated provision for depreciation	17,039	2,020,463	2,162,173	(175,395)	4,024,280
	79,332	4,177,313	3,249,679	(209,286)	7,297,038
Construction work in progress	8,809	519,651	534,284		1,062,744
	88,141	4,696,964	3,783,963	(209,286)	8,359,782
INVESTMENTS:					
Nuclear plant decommissioning trusts			1,145,846		1,145,846
Investment in associated companies	4,941,763			(4,941,763)	
Other	374	11,128	202		11,704
	4,942,137	11,128	1,146,048	(4,941,763)	1,157,550
DEFERRED CHARGES AND OTHER ASSETS:					
Accumulated deferred income tax benefits	42,986	412,427		(455,413)	
Customer intangibles	133,968				133,968
Goodwill	24,248				24,248
Property taxes		16,463	24,649		41,112
Unamortized sale and leaseback costs		10,828		62,558	73,386

Derivatives	97,603				97,603
Other	21,018	70,810	14,463	(57,602)	48,689
	319,823	510,528	39,112	(450,457)	419,006
	$ 6,374,608	$ 6,116,512	$ 5,510,859	$ (5,939,544)	$ 12,062,435
LIABILITIES AND CAPITALIZATION					
CURRENT LIABILITIES:					
Currently payable long-term debt	$ 100,775	$ 418,832	$ 632,106	$ (19,578)	$ 1,132,135
Short-term borrowings-					
Associated companies		11,561			11,561
Other					
Accounts payable-					
Associated companies	351,172	212,620	249,820	(346,989)	466,623
Other	139,037	102,154			241,191
Accrued taxes	3,358	36,187	30,726	(142)	70,129
Derivatives	266,411				266,411
Other	51,619	147,754	15,156	37,142	251,671
	912,372	929,108	927,808	(329,567)	2,439,721
CAPITALIZATION:					
Common stockholder s equity	3,788,245	2,514,775	2,413,580	(4,928,859)	3,787,741
Long-term debt and other long-term obligations	1,518,586	2,118,791	793,250	(1,249,752)	3,180,875
	5,306,831	4,633,566	3,206,830	(6,178,611)	6,968,616
NONCURRENT LIABILITIES:					
Deferred gain on sale and leaseback transaction				959,154	959,154
Accumulated deferred income taxes			448,115	(390,520)	57,595
Accumulated deferred investment tax credits		33,280	20,944		54,224
Asset retirement obligations		26,780	865,271		892,051
Retirement benefits	48,214	236,946			285,160
Property taxes		16,463	24,649		41,112
Lease market valuation liability		216,695			216,695
Derivatives	81,393				81,393
Other	25,798	23,674	17,242		66,714
	155,405	553,838	1,376,221	568,634	2,654,098
	$ 6,374,608	$ 6,116,512	$ 5,510,859	$ (5,939,544)	$ 12,062,435

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FIRSTENERGY SOLUTIONS CORP.
CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS
(Unaudited)

For the Three Months Ended March 31, 2011	FES	FGCO	NGC	Eliminations	Consolidated
			(In thousands)		
NET CASH PROVIDED FROM (USED FOR) OPERATING ACTIVITIES	$ (215,124)	$ 267,047	$ 41,702	$	$ 93,625
CASH FLOWS FROM FINANCING ACTIVITIES:					
New Financing-					
Long-term debt		90,190	60,000		150,190
Short-term borrowings, net	321,134	28,509			349,643
Redemptions and Repayments-					
Long-term debt	(130,208)	(141,220)	(60,000)		(331,428)
Other	(430)	(222)	(365)		(1,017)
Net cash provided from (used for) financing activities	190,496	(22,743)	(365)		167,388
CASH FLOWS FROM INVESTING ACTIVITIES:					
Property additions	(2,858)	(39,791)	(116,357)		(159,006)
Sales of investment securities held in trusts			215,620		215,620
Purchases of investment securities held in trusts			(230,912)		(230,912)
Loans from (to) associated companies, net	28,589	(200,516)	90,280		(81,647)
Customer acquisition costs	(1,103)				(1,103)
Other		(6,439)	32		(6,407)
Net cash provided from (used for) investing activities	24,628	(246,746)	(41,337)		(263,455)
Net change in cash and cash equivalents		(2,442)			(2,442)
Cash and cash equivalents at beginning of period		9,273	8		9,281
Cash and cash equivalents at end of period	$	$ 6,831	$ 8	$	$ 6,839

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FIRSTENERGY SOLUTIONS CORP.
CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS
(Unaudited)

For the Three Months Ended March 31, 2010	FES	FGCO	NGC	Eliminations	Consolidated
			(In thousands)		
NET CASH PROVIDED FROM (USED FOR) OPERATING ACTIVITIES	$ (147,718)	$ 40,130	$ 98,692	$	$ (8,896)
CASH FLOWS FROM FINANCING ACTIVITIES:					
Redemptions and Repayments-					
Long-term debt	(197)	(1,081)			(1,278)
Short-term borrowings, net		(9,237)			(9,237)
Other	(453)	(177)	(101)		(731)
Net cash used for financing activities	(650)	(10,495)	(101)		(11,246)
CASH FLOWS FROM INVESTING ACTIVITIES:					
Property additions	(2,103)	(174,163)	(125,337)		(301,603)
Proceeds from asset sales		114,272			114,272
Sales of investment securities held in trusts			272,094		272,094
Purchases of investment securities held in trusts			(284,888)		(284,888)
Loans from associated companies, net	250,908	31,232	39,540		321,680
Customer acquisition costs	(100,615)				(100,615)
Other	178	(977)			(799)
Net cash provided from (used for) investing activities	148,368	(29,636)	(98,591)		20,141
Net change in cash and cash equivalents		(1)			(1)
Cash and cash equivalents at beginning of period		3	9		12
Cash and cash equivalents at end of period	$	$ 2	$ 9	$	$ 11

Item 2. Management s Discussion and Analysis of Registrant and Subsidiaries

FIRSTENERGY CORP.
MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

EXECUTIVE SUMMARY

Earnings available to FirstEnergy Corp. in the first quarter of 2011 were $50 million, or basic and diluted earnings of $0.15 per share of common stock, compared with $155 million, or basic and diluted earnings of $0.51 per share of common stock in the first quarter of 2010. The principal reasons for the decreases are summarized below.

Change in Basic Earnings Per Share From Prior Year		2011
Basic earnings Per Share First Quarter 2010	$	0.51
Non-core asset sales/impairments		(0.03)
Trust securities impairments		0.01
Mark-to-market adjustments		0.09
Income tax charge from healthcare legislation 2010		0.04
Regulatory charges 2011		(0.04)
Regulatory charges 2010		0.08
Merger-related costs		(0.34)
Revenues		(0.26)
Fuel and purchased power		0.21
Transmission expense		(0.07)
Amortization of regulatory assets, net		0.07
Interest expense		0.03
Merger accounting commodity contracts		(0.04)
Allegheny earnings contribution*		0.13
Additional shares issued		(0.06)
Other		(0.18)
Basic earnings Per Share First Quarter 2011	$	0.15

* Excludes merger accounting commodity contracts, regulatory charges, mark-to-market adjustments and merger-related costs that are shown separately.

Merger

On February 25, 2011, the merger between FirstEnergy and Allegheny closed. Pursuant to the terms of the Agreement and Plan of Merger between FirstEnergy, Element Merger Sub, Inc., a Maryland corporation and a wholly-owned subsidiary of FirstEnergy (Merger Sub), and AE, Merger Sub merged with and into AE with AE continuing as the surviving corporation and a wholly-owned subsidiary of FirstEnergy. As part of the merger, AE shareholders received 0.667 of a share of FirstEnergy common stock for each AE share outstanding as of the merger completion date and all outstanding AE equity-based employee compensation awards were converted into FirstEnergy equity-based awards on the same basis.

In connection with the merger, FirstEnergy recorded approximately $82 million and $14 million of merger transaction costs during the first quarter of 2011 and 2010, respectively. FirstEnergy s consolidated financial statements include Allegheny s results of operations and financial position effective February 25, 2011. In addition, in the three months ended March 31, 2011, $75 million of pre-tax merger integration costs and $24 million of charges from merger settlements approved by regulatory agencies have been recognized. Charges resulting from merger settlements are not expected to be material in future periods.

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Operational Matters

Fremont Energy Center

On March 14, 2011, FirstEnergy entered into a definitive agreement to sell Fremont Energy Center (707 MW) to American Municipal Power, Inc. (AMP). Under the terms of the agreement, AMP will purchase Fremont Energy Center for approximately $485 million, based on 685 MW of output. The purchase price would be incrementally increased, not to exceed an additional $16 million, to reflect additional output and transmission export capacity to its nameplate capacity of 707 MW. In addition, AMP would reimburse FirstEnergy up to $25.3 million for construction costs incurred from February 1, 2011 through the closing date. On April 19, 2011, FGCO filed an application with the FERC for authorization to sell the Fremont Energy Center, including related capacity supply obligations, to AMP. The transaction is expected to close in July 2011.

Perry Refueling

FENOC shutdown the Perry Nuclear Plant on April 18, 2011, for scheduled refueling and maintenance. During the outage 284 of the 748 fuel assemblies will be exchanged and maintenance safety inspections will be conducted while the unit is off line. Preventative maintenance to ensure continued safe and reliable operations will be preformed, including replacing several control rod blades, rewinding the generator and testing more than 100 valves. On April 25, 2011, the NRC began a Special Inspection to review the circumstances surrounding work activities to remove a source range monitor from the reactor core on April 22, 2011.

Beaver Valley Refueling

On April 11, 2011, FENOC announced that Beaver Valley Unit 2 (911 MW) returned to service following a March 7, 2011 shutdown for refueling and maintenance. During the outage 60 of the 157 fuel assemblies were exchanged, safety inspections were conducted, and numerous maintenance and improvement projects were completed.

Seneca Plant Maintenance

In March 2011, FirstEnergy announced that the Seneca Pumped-Storage Hydroelectric facility (451 MW) will repave its Upper Reservoir, overhaul the shutoff valves and perform routine maintenance activities.

TrAIL

On April 15, 2011, the TrAIL 500 kV line segment from Meadowbrook substation to Loudoun substation in Virginia was successfully energized and is carrying load. The other segments are planned to be energized in May. The entire TrAIL line is scheduled to be completed and placed in service no later than June 2011.

Signal Peak

On March 16, 2011, Signal Peak Energy received a letter from the MSHA indicating that its mine is no longer being considered for a pattern of potential violations notice.

Financial Matters

On March 16, 2011, Penelec and Met-Ed extended for three years the LOCs supporting two series of PCRBs currently outstanding in a variable interest rate mode totaling $49 million.

On March 17 and April 1, 2011, FES and Penelec completed the remarketing of six series of PCRBs totaling $328 million. Each of these series either remained in or was converted to a variable interest rate mode supported by a three-year bank LOC. In connection with the remarketings, approximately $207 million aggregate principal amount of FMBs previously delivered to LOC providers were cancelled, and approximately $50 million aggregate principal amount of FMBs previously delivered to secure PCRBs are expected to be cancelled on May 31, 2011.

On March 29, 2011, FES repaid a $100 million two-year term loan facility secured by FMBs that was scheduled to mature March 31, 2011. On April 8, 2011, FirstEnergy entered into a new $150 million unsecured term loan with an April 2013 maturity.

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Regulatory Matters

Ohio Energy Efficiency (EE) and Peak Demand Reduction (DR) Portfolio Plan

On March 23, 2011, the PUCO approved the three-year EE and DR portfolio plan for the Ohio Companies. The Ohio Companies plan was developed to comply with the EE mandate in Ohio s SB 221, passed in 2008. This law requires that utilities in Ohio reduce energy usage by 22.2 percent by 2025 and peak demand by 7.75 percent by 2018, develop a portfolio plan, and meet annual benchmarks to measure progress.

Penn SREC

On March 11, 2011, the PPUC approved the results of the Penn procurement of SRECs to meet Pennsylvania s Alternative Energy Portfolio Standards through 2020. One SREC represents the solar renewable energy attributes of one MWH of generation from a solar generating facility. Penn contracted for 19,800 SREC s. This purchase of SRECs is equivalent to approximately 2,200 MWH of solar power generation annually over the next nine years. The average cost is $199.09 per SREC, with deliveries scheduled for June 2011 through May 2020.

FIRSTENERGY S BUSINESS

With the completion of the Allegheny merger in the first quarter of 2011, FirstEnergy reorganized its management structure, which resulted in changes to its operating segments to be consistent with the manner in which management views the business. The new structure supports the combined company s primary operations distribution, transmission, generation and the marketing and sale of its products. The external segment reporting is consistent with the internal financial reporting utilized by FirstEnergy s chief executive officer (its chief operating decision maker) to regularly assess the performance of the business and allocate resources. FirstEnergy now has three reportable operating segments Regulated Distribution, Regulated Independent Transmission and Competitive Energy Services.

Prior to the change in composition of business segments, FirstEnergy s business was comprised of two reportable operating segments. The Energy Delivery Services segment included FirstEnergy s then eight existing utility operating companies that transmit and distribute electricity to customers and purchase power to serve their POLR and default service requirements. The Competitive Energy Services segment was comprised of FES, which supplies electric power to end-use customers through retail and wholesale arrangements. The Other segment consisted of corporate items and other businesses that were below the quantifiable threshold for separate disclosure. Disclosures for FirstEnergy s operating segments for 2010 have been reclassified to conform to the current presentation.

The changes in FirstEnergy s reportable segments during the first quarter of 2011 consisted primarily of the following:

Energy Delivery Services was renamed Regulated Distribution and the operations of MP, PE and WP, which were acquired as part of the merger with Allegheny, and certain regulatory asset recovery mechanisms formerly included in the Other segment, were placed into this segment.

A new Regulated Independent Transmission segment was created consisting of ATSI, and the operations of TrAIL Company and FirstEnergy s interest in PATH; TrAIL and PATH were acquired as part of the merger with Allegheny. The transmission assets and operations of JCP&L, Met-Ed, Penelec, MP, PE and WP remain within the Regulated Distribution segment.

AE Supply, an operator of generation facilities that was acquired as part of the merger with Allegheny, was placed into the Competitive Energy Services segment.

Financial information for each of FirstEnergy s reportable segments is presented in the table below, which includes financial results for the Allegheny subsidiaries beginning February 25, 2011. FES and the Utilities do not have separate reportable operating segments.

The Regulated Distribution segment distributes electricity through FirstEnergy s ten utility operating companies, serving approximately 6 million customers within 67,000 square miles of Ohio, Pennsylvania, West Virginia, Virginia, Maryland, New Jersey and New York, and purchases power for its POLR and default service requirements in Ohio, Pennsylvania and New Jersey. This segment also includes the transmission operations of JCP&L, Met-Ed, Penelec, WP, MP and PE and the regulated electric generation facilities in West Virginia and New Jersey which MP and JCP&L, respectively, own or contractually control.

The Regulated Distribution segment s revenues are primarily derived from the delivery of electricity within FirstEnergy s service areas, cost recovery of regulatory assets and the sale of electric generation service to retail customers who have not selected an alternative supplier (POLR or default service) in its Maryland, New Jersey, Ohio and Pennsylvania franchise areas. Its results reflect the commodity costs of securing electric generation from FES and AE Supply and from non-affiliated power suppliers and the deferral and amortization of certain fuel costs.

The Regulated Independent Transmission segment transmits electricity through transmission lines. Its revenues are primarily derived from the formula rate recovery of costs and a return on debt and equity for capital expenditures in connection with TrAIL, PATH and other projects and revenues from providing transmission services to electric energy providers, power marketers and receiving transmission-related revenues from operation of a portion of the FirstEnergy transmission system. Its results reflect the net PJM and MISO transmission expenses related to the delivery of the respective generation loads. On June 1, 2011, the ATSI transmission assets currently dedicated to MISO are scheduled to be integrated into the PJM market. This integration brings all of FirstEnergy s assets into one RTO.

The Competitive Energy Services segment, through FES, supplies electric power to end-use customers through retail and wholesale arrangements, including associated company power sales to meet all or a portion of the POLR and default service requirements of FirstEnergy s Ohio and Pennsylvania utility subsidiaries and competitive retail sales to customers primarily in Ohio, Pennsylvania, Illinois, Maryland, Michigan and New Jersey. FES purchases the entire output of the 18 generating facilities which it owns and operates through its FGCO subsidiary (fossil and hydroelectric generating facilities) and owns, through its NGC subsidiary, FirstEnergy s nuclear generating facilities. FENOC, a separate subsidiary of FirstEnergy, operates and maintains NGC s nuclear generating facilities as well as the output relating to leasehold interests of OE and TE in certain of those facilities that are subject to sale and leaseback arrangements with non-affiliates, pursuant to full output, cost-of-service PSAs.

The Competitive Energy Services segment also includes Allegheny s unregulated electric generation operations, including AE Supply and AE Supply s interest in AGC. AE Supply owns, operates and controls the electric generation capacity of its 18 facilities. AGC owns and sells generation capacity to AE Supply and MP, which own approximately 59% and 41% of AGC, respectively. AGC s sole asset is a 40% undivided interest in the Bath County, Virginia pumped-storage hydroelectric generation facility and its connecting transmission facilities. All of AGC s revenues are derived from sales of its 1,109 MW share of generation capacity from the Bath County generation facility to AE Supply and MP.

This business segment controls approximately 20,000 MWs of capacity and also purchases electricity to meet sales obligations. The segment s net income is primarily derived from affiliated and non-affiliated electric generation sales less the related costs of electricity generation, including purchased power and net transmission (including congestion) and ancillary costs charged by PJM and MISO to deliver energy to the segment s customers.

The Other segment contains corporate items and other businesses that are below the quantifiable threshold for separate disclosure as a reportable segment.

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RESULTS OF OPERATIONS

The financial results discussed below include revenues and expenses from transactions among FirstEnergy s business segments. A reconciliation of segment financial results is provided in Note 13 to the consolidated financial statements. Earnings available to FirstEnergy by major business segment were as follows:

	Three Months Ended March 31 2011	2010	Increase (Decrease)
	(In millions, except per share data)		
Earnings By Business Segment:			
Regulated Distribution	$ 96	$ 103	$ (7)
Competitive Energy Services	5	69	(64)
Regulated Independent Transmission	13	12	1
Other and reconciling adjustments*	(64)	(29)	(35)
Total	$ 50	$ 155	$ (105)
Basic Earnings Per Share	$ 0.15	$ 0.51	$ (0.36)
Diluted Earnings Per Share	$ 0.15	$ 0.51	$ (0.36)

* Consists primarily of interest expense related to holding company debt, corporate support services revenues and expenses, noncontrolling interests and the elimination of intersegment transactions.

Summary of Results of Operations First Quarter 2011 Compared with First Quarter 2010

Financial results for FirstEnergy s major business segments in the first quarter of 2011 and 2010 were as follows:

First Quarter 2011 Financial Results	**Regulated Distribution**	**Competitive Energy Services**	**Regulated Independent Transmission (In millions)**	**Other and Reconciling Adjustments**	**FirstEnergy Consolidated**
Revenues:					
External					
Electric	$ 2,175	$ 1,162	$	$	$ 3,337
Other	93	92	67	(45)	207
Internal		343		(311)	32
Total Revenues	2,268	1,597	67	(356)	3,576
Expenses:					
Fuel	24	429			453
Purchased power	1,179	318		(311)	1,186
Other operating expenses	386	648	17	(18)	1,033
Provision for depreciation	116	88	10	6	220
Amortization of regulatory assets	129		3		132
Deferral of new regulatory assets					
General taxes	176	44	8	9	237
Impairment of long-lived assets					
Total Expenses	2,010	1,527	38	(314)	3,261

Operating Income	258	70	29	(42)	315
Other Income (Expense):					
Investment income	25	6		(10)	21
Interest expense	(132)	(78)	(9)	(12)	(231)
Capitalized interest	1	10		7	18
Total Other Expense	(106)	(62)	(9)	(15)	(192)
Income Before Income Taxes	152	8	20	(57)	123
Income taxes	56	3	7	12	78
Net Income (Loss)	96	5	13	(69)	45
Loss attributable to noncontrolling interest				(5)	(5)
Earnings available to FirstEnergy Corp.	$ 96	$ 5	$ 13	$ (64)	$ 50

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First Quarter 2010 Financial Results	Regulated Distribution	Competitive Energy Services	Regulated Independent Transmission (In millions)	Other and Reconciling Adjustments	FirstEnergy Consolidated
Revenues:					
External					
Electric	$ 2,398	$ 669	$	$	$ 3,067
Other	86	50	57	(28)	165
Internal		674		(607)	67
Total Revenues	2,484	1,393	57	(635)	3,299
Expenses:					
Fuel		334			334
Purchased power	1,395	450		(607)	1,238
Other operating expenses	359	352	14	(24)	701
Provision for depreciation	104	77	9	3	193
Amortization of regulatory assets	209		3		212
Deferral of new regulatory assets					
General taxes	154	37	7	7	205
Impairment of long-lived assets					
Total Expenses	2,221	1,250	33	(621)	2,883
Operating Income	263	143	24	(14)	416
Other Income (Expense):					
Investment income	26	1		(11)	16
Interest expense	(125)	(56)	(5)	(27)	(213)
Capitalized interest	1	23		17	41
Total Other Expense	(98)	(32)	(5)	(21)	(156)
Income Before Income Taxes	165	111	19	(35)	260
Income taxes	62	42	7		111
Net Income (Loss)	103	69	12	(35)	149
Loss attributable to noncontrolling interest				(6)	(6)
Earnings available to FirstEnergy Corp.	$ 103	$ 69	$ 12	$ (29)	$ 155

Changes Between First Quarter 2011 and First Quarter 2010 Financial Results Increase (Decrease)	Regulated Distribution	Competitive Energy Services	Regulated Independent Transmission (In millions)	Other and Reconciling Adjustment	FirstEnergy Consolidated
Revenues:					
External					
Electric	$ (223)	$ 493	$	$	$ 270
Other	7	42	10	(17)	42
Internal		(331)		296	(35)
Total Revenues	(216)	204	10	279	277
Expenses:					
Fuel	24	95			119
Purchased power	(216)	(132)		296	(52)
Other operating expenses	27	296	3	6	332
Provision for depreciation	12	11	1	3	27
Amortization of regulatory assets	(80)				(80)
Deferral of new regulatory assets					
General taxes	22	7	1	2	32
Impairment of long-lived assets					
Total Expenses	(211)	277	5	307	378
Operating Income	(5)	(73)	5	(28)	(101)
Other Income (Expense):					
Investment income	(1)	5		1	5
Interest expense	(7)	(22)	(4)	15	(18)
Capitalized interest		(13)		(10)	(23)
Total Other Expense	(8)	(30)	(4)	6	(36)
Income Before Income Taxes	(13)	(103)	1	(22)	(137)
Income taxes	(6)	(39)		12	(33)
Net Income (Loss)	(7)	(64)	1	(34)	(104)
Loss attributable to noncontrolling interest				1	1
Earnings available to FirstEnergy Corp.	$ (7)	$ (64)	$ 1	$ (35)	$ (105)

Regulated Distribution — First Quarter 2011 Compared with First Quarter 2010

Net income decreased by $7 million in the first quarter of 2011 compared to the first quarter of 2010, primarily due to lower generation and transmission revenues and merger-related costs associated with the Allegheny merger, partially offset by lower purchased power costs and amortization of regulatory assets.

Revenues

The decrease in total revenues resulted from the following sources:

Revenues by Type of Service	Three Months Ended March 31 2011	2010	Increase (Decrease)
	(In millions)		
Pre-merger companies			
Distribution services	$ 909	$ 883	$ 26
Generation sales:			
Retail	873	1,178	(305)
Wholesale	116	217	(101)
Total generation sales	989	1,395	(406)
Transmission	37	160	(123)
Other	58	46	12
Total pre-merger companies	1,993	2,484	(491)
Allegheny companies	275		275
Total Revenues	$ 2,268	$ 2,484	$ (216)

The increase in distribution service revenues reflected higher distribution deliveries in the first quarter of 2011 compared to the same period in 2010. Distribution deliveries (excluding the Allegheny companies) increased 650,000 MWH (2.4%) to 27,538,000 MWH in the first quarter of 2011 from 26,888,000 MWH in the first quarter of 2010. The increase in distribution deliveries by customer class is summarized in the following table:

Electric Distribution KWH Deliveries	2011	2010	Increase (Decrease)
	(in thousands)		
Pre-merger companies			
Residential	10,638	10,455	1.8%
Commercial	7,929	7,953	(0.3)%
Industrial	8,841	8,351	5.9%
Other	130	129	0.8%
Total pre-merger companies	27,538	26,888	2.4%
Allegheny companies	3,540		
Total Electric Distribution MWH Deliveries	31,078	26,888	15.6%

Higher deliveries to residential customers reflected increased weather-related usage in the first quarter of 2011, as heating degree days increased by 5.2% from the same period in 2010. The increase in distribution deliveries to industrial customers was primarily due to recovering economic conditions in FirstEnergy s service territory compared to the first quarter of 2010. In the industrial sector, KWH deliveries increased by 12.8% to major steel customers, 4.7% to refinery customers and 8.4% to chemical customers.

The following table summarizes the price and volume factors contributing to the $406 million decrease in generation revenues in the first quarter of 2011 compared to the first quarter of 2010:

Source of Change in Generation Revenues	**Increase (Decrease) (In millions)**
Retail:	
Effect of 32.4% decrease in sales volumes	$ (382)
Change in prices	77
	(305)
Wholesale:	
Effect of 3.9% increase in sales volumes	8
Change in prices	(109)
	(101)
Net Decrease in Generation Revenues	$ (406)

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The decrease in retail generation sales volumes was primarily due to an increase in customer shopping in the Ohio Companies , Met-Ed s and Penelec s service territories in the first quarter of 2011, compared to the first quarter of 2010. Total generation provided by alternative suppliers as a percentage of total KWH deliveries increased to 73% from 53% for the Ohio Companies and to 40% from 2% in Met-Ed s and Penelec s service areas.

The decrease in wholesale generation revenues reflected lower RPM revenues for Met-Ed and Penelec in the PJM market. Transmission revenues decreased $123 million due to the termination of Met-Ed s and Penelec s transmission tariff effective January 1, 2011. Transmission costs are now a component of the cost of generation established under Met-Ed s and Penelec s generation procurement plan.

The Allegheny companies added $275 million in revenues for the first quarter of 2011, including $69 million for distribution services, $190 million for generation sales and $16 million relating to PJM transmission revenues.

Expenses

Total expenses decreased by $140 million due to the following:

Purchased power costs, excluding the Allegheny companies, were $356 million lower in the first quarter of 2011 due primarily to a decrease in sales volume requirements. The decrease in power purchased from FES reflected the increase in customer shopping described above and the termination of Met-Ed s and Penelec s partial requirements PSA with FES at the end of 2010. The increase in volumes purchased from non-affiliates under Met-Ed s and Penelec s generation procurement plan effective January 1, 2011 was offset by a decrease in RPM expenses in the PJM market. The Allegheny companies added $140 million in purchased power costs in the first quarter of 2011.

Source of Change in Purchased Power	**Increase (Decrease) (In millions)**
Pre-merger companies	
Purchases from non-affiliates:	
Change due to decreased unit costs	$ (186)
Change due to increased volumes	188
	2
Purchases from FES:	
Change due to increased unit costs	36
Change due to decreased volumes	(412)
	(376)
Decrease in costs deferred	18
Total pre-merger companies	(356)
Purchases by Allegheny companies	140
Net Decrease in Purchased Power Costs	$ (216)

Transmission expenses decreased $98 million primarily due to lower PJM network transmission expenses and congestion costs of $110 million for Met-Ed and Penelec, partially offset by transmission expenses for the Allegheny companies of $12 million in the first quarter of 2011.

Met-Ed and Penelec defer or amortize the difference between revenues from their transmission rider and transmission costs incurred with no material effect on earnings.
Energy Efficiency program costs, which are also recovered through rates, increased $16 million.
Material costs associated with maintenance activities increased $10 million in the first quarter of 2011 compared to the same period last year.
A provision for excess and obsolete material of $13 million was recognized in the first quarter of 2011 relating to revised inventory practices adopted in conjunction with the Allegheny merger.
Depreciation expense increased $12 million due to property additions since the first quarter of 2010.

Net amortization of regulatory assets decreased $80 million due primarily to generation-related rate deferrals for the Ohio Companies, Met-Ed and Penelec and reduced net PJM transmission cost amortization.

General taxes increased $22 million due to higher property taxes and gross receipts taxes in the first quarter of 2011.

Fuel expenses for MP were $24 million in the first quarter of 2011.

Operating expenses for the Allegheny companies were $38 million in the first quarter of 2011.

Merger-related costs incurred by the Allegheny companies were $48 million in the first quarter of 2011.

Other Expense

Other expense increased $8 million in the first quarter of 2011 due to interest expense on debt of the Allegheny companies.

Regulated Independent Transmission — First Quarter 2011 Compared with First Quarter 2010

Net income increased by $1 million in the first quarter of 2011 compared to the first quarter of 2010 due to earnings associated with TrAIL and PATH ($5 million), partially offset by reduced earnings for ATSI ($4 million).

Revenues

Revenues by transmission asset owner are shown in the following table:

Revenues by Transmission Asset Owner	**Three Months Ended March 31 2011**	**2010**	**Increase (Decrease)**
	(In millions)		
ATSI	$ 52	$ 57	$ (5)
TrAIL	14		14
PATH	1		1
Total Revenues	$ 67	$ 57	$ 10

Expenses

Total expenses increased by $5 million due primarily to operating expenses associated with TrAIL and PATH, which were $3 million in the first quarter of 2011.

Other Expense

Other expense increased $4 million in the first quarter of 2011 due to additional interest expense associated with TrAIL.

Competitive Energy Services — First Quarter 2011 Compared with First Quarter 2010

Net income decreased by $64 million in the first quarter of 2011, compared to the first quarter of 2010, primarily due to increased transmission expense, an inventory reserve adjustment, non-core asset impairments and the effect of mark-to-market adjustments.

Revenues

Total revenues increased $204 million in the first quarter of 2011 primarily due to growth in direct and government aggregation sales and the inclusion of the Allegheny companies, partially offset by a decline in POLR sales.

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The increase in total revenues resulted from the following sources:

Revenues by Type of Service	Three Months Ended March 31 2011	2010	Increase (Decrease)
	(In millions)		
Direct and Government Aggregation	$ 840	$ 512	$ 328
POLR	369	673	(304)
Wholesale	96	91	5
Transmission	26	17	9
REC s	32	67	(35)
Other	41	33	8
Allegheny Companies	193		193
Total Revenues	$ 1,597	$ 1,393	$ 204
Allegheny Companies			
Direct and Government Aggregation	$ 9		
POLR	68		
Wholesale	91		
Transmission	12		
Other	13		
Total Revenues	$ 193		

MWH Sales by Type of Service	Three Months Ended March 31 2011	2010	Increase (Decrease)
	(In thousands)		
Direct	9,671	5,854	65.2%
Government Aggregation	4,310	2,732	57.8%
POLR	5,714	13,276	(57.0)%
Wholesale	1,113	898	23.9%
Allegheny Companies	2,636		
Total Sales	23,444	22,760	3.0%
Allegheny Companies			
Direct	145		
POLR	812		
Structured Sales	284		
Wholesale	1,395		
Total Sales	2,636		

The increase in direct and government aggregation revenues of $328 million resulted from increased revenue from the acquisition of new commercial and industrial customers as well as new government aggregation contracts with communities in Ohio that provided generation to approximately 1.5 million residential and small commercial customers at the end of March 2011 compared to approximately 1.1 million such customers at the end of March 2010. In addition, sales to residential and small commercial customers were bolstered by weather in the delivery area that was 5.2% colder than in 2010.

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The decrease in POLR revenues of $304 million was due to lower sales volumes to the Pennsylvania and Ohio Companies, partially offset by increased sales to non-associated companies and higher unit prices to the Pennsylvania Companies. Participation in POLR auctions and RFPs are expected to continue, but the concentration of these sales will primarily be dependent on our success in our direct retail and aggregation sales channels.
Wholesale revenues increased $5 million due to increased volumes partially offset by lower wholesale prices. The higher sales volumes were the result of increased short term (net hourly positions) transactions in MISO. $22 million of wholesale revenue resulted from long positions in MISO that were unable to be netted with short positions in PJM, due to separate settlement requirements with each RTO.
The following tables summarize the price and volume factors contributing to changes in revenues (excluding the Allegheny companies):

Source of Change in Direct and Government Aggregation	**Increase (Decrease)** *(In millions)*
Direct Sales:	
Effect of 65.2% increase in sales volumes	$ 223
Change in prices	(4)
	219
Government Aggregation:	
Effect of 57.8% increase in sales volumes	100
Change in prices	9
	109
Net Increase in Direct and Government Aggregation Revenues	$ 328

Source of Change in POLR Revenues	**Increase (Decrease)** *(In millions)*
POLR:	
Effect of 57.0% decrease in sales volumes	$ (384)
Change in prices	80
	(304)

Source of Change in Wholesale Revenues	**Increase (Decrease)** *(In millions)*
Other Wholesale:	
Effect of 23.9% increase in sales volumes	12
Change in prices	(7)
	5

Transmission revenues increased $9 million due primarily to higher MISO congestion revenue. The revenues derived from the sale of RECs declined $35 million in the first quarter of 2011.

Expenses

Total expenses increased $277 million in the first quarter of 2011 due to the following:

- Fuel costs increased $13 million primarily due to increased volumes ($31 million), partially offset by lower unit prices ($18 million). Volumes increased due to higher generation at the fossil units. Unit prices declined primarily due to improved generating unit availability at more efficient units, partially offset by increased coal transportation costs and higher nuclear fuel unit prices following the refueling outages that occurred in 2010.
- Purchased power costs decreased $153 million due primarily to lower volumes purchased ($185 million) partially offset by higher unit costs ($32 million). The decrease in volume primarily relates to the absence in 2011 of a 1,300 MW third party contract associated with serving Met-Ed and Penelec. $35 million of purchased power expense resulted from long positions in MISO that were unable to be netted with short positions in PJM, due to separate settlement requirements with each RTO.
- Fossil operating costs increased $1 million due primarily to higher labor costs partially offset by lower professional and contractor costs and reduced coal sale losses.
- Nuclear operating costs increased $15 million due primarily to higher labor and related benefits, partially offset by lower professional and contractor costs.

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Transmission expenses increased $111 million due primarily to increases in PJM of $108 million from higher congestion, network, and loss expense and MISO transmission expenses of $3 million due to higher congestion costs.

General taxes increased $3 million due to an increase in revenue-related taxes.

Other expenses increased $65 million primarily due to: a $54 million provision for excess and obsolete material relating to revised inventory practices adopted in connection with the Allegheny merger; a $13 million impairment charge related to non-core assets; an $11 million increase in intercompany billings; and reduced mark-to-market adjustments of $15 million.

The inclusion of approximately one month of the Allegheny companies operations contributed $222 million to expenses, including a $29 million mark-to-market adjustment relating primarily to power contracts.

Other Expense

Total other expense in the first quarter of 2011 was $30 million higher than the first quarter of 2010, primarily due to a $35 million increase in net interest expense partially offset by an increase in nuclear decommissioning trust investment income ($5 million). The increase in interest expense was primarily due to the inclusion of the Allegheny companies ($20 million) and lower capitalized interest ($13 million) associated with the completion of the Sammis AQC project in 2010.

Other First Quarter of 2011 Compared with First Quarter of 2010

Financial results from other operating segments and reconciling items, including interest expense on holding company debt and corporate support services revenues and expenses, resulted in a $35 million decrease in earnings available to FirstEnergy in the first quarter of 2011 compared to the same period in 2010. The decrease resulted primarily from reduced other revenues ($17 million) representing reconciling adjustments combined with increased income taxes ($12 million).

Regulatory Assets

FirstEnergy and the Utilities prepare their consolidated financial statements in accordance with the authoritative guidance for accounting for certain types of regulation. Under this guidance, regulatory assets represent incurred costs that have been deferred because of their probable future recovery from customers through regulated rates. Regulatory liabilities represent amounts that are expected to be credited to customers through future regulated rates or amounts collected from customers for costs not yet incurred. FirstEnergy and the Utilities net their regulatory assets and liabilities based on federal and state jurisdictions. The following table provides the balance of net regulatory assets by company as of March 31, 2011 and December 31, 2010 and changes during the three months then ended:

Regulatory Assets	**March 31, 2011**	**December 31, 2010**	**Increase (Decrease)**
		(In millions)	
OE	$ 385	$ 400	$ (15)
CEI	337	370	(33)
TE	84	72	12
JCP&L	460	513	(53)
Met-Ed	285	296	(11)
Penelec	179	163	16
Other*	354	12	342
Total	$ 2,084	$ 1,826	$ 258

* 2011 includes $343 million related to the Allegheny companies.

The following tables provide information about the composition of net regulatory assets as of March 31, 2011 and December 31, 2010 and the changes during the three months then ended:

Regulatory Assets by Source	March 31, 2011	December 31, 2010	Increase (Decrease)
		(In millions)	
Regulatory transition costs	$ 592	$ 770	$ (178)
Customer receivables for future income taxes	488	326	162
Loss on reacquired debt	56	48	8
Employee postretirement benefits	14	16	(2)
Nuclear decommissioning, decontamination and spent fuel disposal costs	(200)	(184)	(16)
Asset removal costs	(220)	(237)	17
MISO/PJM transmission costs	280	184	96
Deferred generation costs	574	386	188
Distribution costs	333	426	(93)
Other	167	91	76
Total	$ 2,084	$ 1,826	$ 258

FirstEnergy had $390 million of net regulatory liabilities as of March 31, 2011, which includes $378 million of net regulatory liabilities acquired as part of the merger with AE that are primarily related to asset removal costs.
Regulatory assets that do not earn a current return totaled approximately $297 million as of March 31, 2011.
Regulatory assets not earning a current return primarily for certain all-electric residential discounts and municipal taxes by OE, CEI and TE are approximately $53 million, $32 million and $4 million, respectively. The timing of expected recovery of these assets cannot be determined at this time.
Regulatory assets not earning a current return primarily for regulatory transition costs by Met-Ed and Penelec are approximately $114 million and $5 million, respectively, and are expected to be recovered by 2020.
Regulatory assets not earning a current return primarily for certain storm damage costs and pension and postretirement benefits by JCP&L are approximately $37 million. The timing of expected recovery of these assets cannot be determined at this time.
Regulatory assets not earning a current return primarily for certain deferred generation costs are approximately $52 million by FirstEnergy s other utility subsidiaries are expected to be recovered over various periods though 2012.

CAPITAL RESOURCES AND LIQUIDITY

As of March 31, 2011, FirstEnergy had cash and cash equivalents of approximately $1.1 billion available to fund investments, operations and capital expenditures. To fund liquidity and capital requirements for 2011 and beyond, FirstEnergy may rely on internal and external sources of funds. Short-term cash requirements not met by cash provided from operations are generally satisfied through short-term borrowings. Long-term cash needs may be met through issuances of debt and/or equity securities.
FirstEnergy expects its existing sources of liquidity to remain sufficient to meet its anticipated obligations and those of its subsidiaries. FirstEnergy s business is capital intensive, requiring significant resources to fund operating expenses, construction expenditures, scheduled debt maturities and interest and dividend payments. During 2011, FirstEnergy expects to satisfy these requirements with a combination of internal cash from operations and external funds from the capital markets as market conditions warrant. FirstEnergy also expects that borrowing capacity under credit facilities will continue to be available to manage working capital requirements along with continued access to long-term capital markets.
A material adverse change in operations, or in the availability of external financing sources, could impact FirstEnergy s liquidity position and ability to fund its capital resource requirements. To mitigate risk, FirstEnergy s business model stresses financial discipline and a strong focus on execution. Major elements of this business model

include the expectation of: projected cash from operations, opportunities for favorable long-term earnings growth in the competitive generation markets, operational excellence, business plan execution, well-positioned generation fleet, no speculative trading operations, appropriate long-term commodity hedging positions, manageable capital expenditure program, adequately funded pension plan, minimal near-term maturities of existing long-term debt, commitment to a secure dividend and a successful merger integration.

As of March 31, 2011, FirstEnergy s net deficit in working capital (current assets less current liabilities) was principally due to the classification of certain variable interest rate PCRBs as currently payable long-term debt and short-term borrowings. Currently payable long-term debt as of March 31, 2011, included the following (in millions):

Currently Payable Long-term Debt		
PCRBs supported by bank LOCs (1)	$	827
FGCO and NGC unsecured PCRBs (1)		141
Penelec unsecured PCRBs		25
FirstEnergy Corp. unsecured note		250
NGC collateralized lease obligation bonds		50
Sinking fund requirements		49
Other notes		43
	$	1,385

(1) Interest rate mode permits individual debt holders to put the respective debt back to the issuer prior to maturity.

Short-Term Borrowings

FirstEnergy had approximately $486 million of short-term borrowings as of March 31, 2011 and $700 million as of December 31, 2010. FirstEnergy s available liquidity as of April 25, 2011, is summarized in the following table:

Company	**Type**	**Maturity**	**Commitment**		**Available Liquidity**	
			(In millions)			
FirstEnergy(1)	Revolving	Aug. 2012	$	2,750	$	1,983
AE	Revolving	Apr. 2013		250		247
AE Supply(2)	Revolving	Various		1,050		1,000
FE Utilities & TrAIL	Revolving	2013		910		475
		Subtotal	$	4,960	$	3,705
		Cash				1,134
		Total	$	4,960	$	4,839

(1) FirstEnergy Corp. and subsidiary borrowers.

(2) Includes $50 million for AGC.

Revolving Credit Facilities

FirstEnergy has the capability to request an increase in the total commitments available under the $2.75 billion revolving credit facility (included in the borrowing capability table above) up to a maximum of $3.25 billion, subject to the discretion of each lender to provide additional commitments. A total of 25 banks participate in the facility, with no one bank having more than 7.3% of the total commitment. Commitments under the facility are available until August 24, 2012, unless the lenders agree, at the request of the borrowers, to an unlimited number of additional one-year extensions. Generally, borrowings under the facility must be repaid within 364 days. Available amounts for each borrower are subject to a specified sub-limit, as well as applicable regulatory and other limitations.

The following table summarizes the borrowing sub-limits for each borrower under the facilities, as well as the limitations on short-term indebtedness applicable to each borrower under current regulatory approvals and applicable statutory and/or charter limitations as of March 31, 2011:

Borrower	Revolving Credit Facility Sub-Limit	Regulatory and Other Short-Term Debt Limitations
	(In millions)	
FirstEnergy	$ 2,750	$ (1)
FES	1,000	(1)
OE	500	500
Penn	50	33(2)
CEI	250(3)	500
TE	250(3)	500
JCP&L	425	411(2)
Met-Ed	250	300(2)
Penelec	250	300(2)
ATSI	50(4)	50

(1) No limitations.

(2) Excluding amounts that may be borrowed under the regulated companies money pool.

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

(4) The borrowing sub-limit for ATSI may be increased up to $100 million by delivering notice to the administrative agent that ATSI has received regulatory approval to have short-term borrowings up to the same amount.

Under the $2.75 billion revolving credit facility, borrowers may request the issuance of LOCs expiring up to one year from the date of issuance. The stated amount of outstanding LOCs will count against total commitments available under the facility and against the applicable borrower s borrowing sub-limit.

The $2.75 billion revolving credit facility contains financial covenants requiring each borrower to maintain a consolidated debt to total capitalization ratio of no more than 65%, measured at the end of each fiscal quarter. As of March 31, 2011, FirstEnergy s and its subsidiaries debt to total capitalization ratios (as defined under the revolving credit facility) were as follows:

Borrower	
FirstEnergy	57.6%
FES	53.3%
OE	55.0%
Penn	35.0%
CEI	56.4%
TE	58.1%
JCP&L	34.5%
Met-Ed	44.3%
Penelec	54.5%
ATSI	49.6%

As of March 31, 2011, FirstEnergy could issue additional debt of approximately $7.1 billion, or recognize a reduction in equity of approximately $3.8 billion, and remain within the limitations of the financial covenants required by its $2.75 billion revolving credit facility.

The $2.75 billion revolving credit facility, does not contain provisions that restrict the ability to borrow or accelerate payment of outstanding advances as a result of any change in credit ratings. Pricing is defined in pricing grids, whereby the cost of funds borrowed under the facility is related to the credit ratings of the company borrowing the funds.

In addition to the $2.75 billion revolving credit facility, FirstEnergy also has access to an additional $2.2 billion of revolving credit facilities relating to the Allegheny companies. The following table summarizes the borrowing sub-limits for each borrower under the facilities as of March 31, 2011:

Borrower	Revolving Credit Facility Sub-Limit *(In millions)*
AE	$ 250
AE Supply	1,000
MP	110
PE	150
WP	200
AGC	50
TrAIL	450

Under the terms of their individual credit facilities, outstanding debt of AE Supply, MP, PE, WP and AGC may not exceed 65% of the sum of their debt and equity as of the last day of each calendar quarter. Outstanding debt for TrAIL may not exceed 70% and 65% of the sum of its debt and equity as of the last day of each calendar quarter through June 30, 2011 and December 31, 2012, respectively. These provisions limit debt levels of these subsidiaries and also limit the net assets of each subsidiary that may be transferred to AE.

FirstEnergy, the Utilities, FES and AESC are currently pursuing an aggregate of up to $4.0 billion in new multi-year revolving credit facilities to replace a portion of the existing facilities described above.

FirstEnergy Money Pools

FirstEnergy s regulated companies, excluding regulated companies acquired in the Allegheny merger, also have the ability to borrow from each other and the holding company to meet their short-term working capital requirements. A similar but separate arrangement exists among FirstEnergy s unregulated companies. FESC administers these two money pools and tracks surplus funds of FirstEnergy and the respective regulated and unregulated subsidiaries, as well as proceeds available from bank borrowings. Companies receiving a loan under the money pool agreements must repay the principal amount of the loan, together with accrued interest, within 364 days of borrowing the funds. The rate of interest is the same for each company receiving a loan from their respective pool and is based on the average cost of funds available through the pool. The average interest rate for borrowings in the first quarter of 2011 was 0.38% per annum for the regulated companies money pool and 0.47% per annum for the unregulated companies money pool. In March 2011, AE Supply invested $200 million into the unregulated money pool. FirstEnergy and its regulated companies acquired in the Allegheny merger have filed with the appropriate regulatory commissions to receive approval to be part of the FirstEnergy regulated money pool.

Pollution Control Revenue Bonds

As of March 31, 2011, FirstEnergy s currently payable long-term debt included approximately $827 million (FES $778 million, Met-Ed $29 million and Penelec $20 million) of variable interest rate PCRBs, the bondholders of which are entitled to the benefit of irrevocable direct pay bank LOCs. The interest rates on the PCRBs are reset daily or weekly. Bondholders can tender their PCRBs for mandatory purchase prior to maturity with the purchase price payable from remarketing proceeds or, if the PCRBs are not successfully remarketed, by drawings on the irrevocable direct pay LOCs. The subsidiary obligor is required to reimburse the applicable LOC bank for any such drawings or, if the LOC bank fails to honor its LOC for any reason, must itself pay the purchase price.

The LOCs for FirstEnergy variable interest rate PCRBs were issued by the following banks as of March 31, 2011:

LOC Bank	Aggregate LOC Amount(1) *(In millions)*	LOC Termination Date	Reimbursements of LOC Draws Due

CitiBank N.A.	$	166	June 2014	June 2014
The Bank of Nova Scotia		178	Beginning June 2012	Multiple dates(2)
The Royal Bank of Scotland		131	June 2012	6 months
Wachovia Bank		152	March 2014	March 2014
US Bank		60	April 2014	6 months
UBS		272	April 2014	April 2014
Total	$	959		

(1) Includes approximately $10 million of applicable interest coverage.

(2) Shorter of 6 months or LOC termination date ($49 million) and shorter of one year or LOC termination date ($129 million).

On March 17, 2011, FES completed the remarketing of $207 million variable rate PCRBs. These PCRBs remained in a variable interest mode, supported by bank LOC s. Also, on March 1, 2011, FES repurchased $50 million of non-LOC backed fixed rate PCRBs that were subject to purchase on demand by the owner on that date.

On April 1, 2011, FES completed the remarketing of an additional $97 million of non-LOC backed commercial paper rate and fixed rate PCRBs (including the $50 million repurchased on March 1) into variable rate modes with LOC support. Also on April 1, 2011, Penelec completed the remarketing of $25 million of non-LOC backed commercial paper rate PCRBs into a variable rate mode with LOC support.

In connection with the remarketings, approximately $207 aggregate principal amount of FMBs previously delivered to LOC providers were cancelled, and approximately $50 million aggregate principal amount of FMBs delivered to secure PCRBs will be cancelled on May 31, 2011.

Long-Term Debt Capacity

As of March 31, 2011, the Ohio Companies and Penn had the aggregate capability to issue approximately $2.4 billion of additional FMBs on the basis of property additions and retired bonds under the terms of their respective mortgage indentures. The issuance of FMBs by the Ohio Companies is also subject to provisions of their senior note indentures generally limiting the incurrence of additional secured debt, subject to certain exceptions that would permit, among other things, the issuance of secured debt (including FMBs) supporting pollution control notes or similar obligations, or as an extension, renewal or replacement of previously outstanding secured debt. In addition, these provisions would permit OE and CEI to incur additional secured debt not otherwise permitted by a specified exception of up to $118 million and $17 million, respectively. As a result of its indenture provisions, TE cannot incur any additional secured debt. Met-Ed and Penelec had the capability to issue secured debt of approximately $365 million and $346 million, respectively, under provisions of their senior note indentures as of March 31, 2011. In addition, based upon their respective FMB indentures, net earnings and available bondable property additions as of March 31, 2011, MP, PE and WP had the capability to issue approximately $685 million of additional FMBs in the aggregate.

Based upon FGCO s FMB indenture, net earnings and available bondable property additions as of March 31, 2011, FGCO had the capability to issue $2.4 billion of additional FMBs under the terms of that indenture. Based upon NGC s FMB indenture, net earnings and available bondable property additions, NGC had the capability to issue $1.2 billion of additional FMBs as of March 31, 2011.

FirstEnergy s access to capital markets and costs of financing are influenced by the ratings of its securities. On March 1, 2011, Fitch affirmed the ratings and outlook of FirstEnergy and its subsidiaries. On February 25, 2011, Moody s affirmed the ratings and stable outlook of FirstEnergy and its regulated utilities, upgraded AE s senior unsecured ratings to Baa3 from Ba1 and placed the ratings for FES under review for possible downgrade. The following table displays FirstEnergy s and its subsidiaries securities ratings as of March 31, 2011.

	Senior Secured			Senior Unsecured		
Issuer	**S&P**	**Moody s**	**Fitch**	**S&P**	**Moody s**	**Fitch**
FirstEnergy Corp.				BB+	Baa3	BBB
Allegheny				BB+	Baa3	BBB-
FES				BBB-	Baa2	BBB
AE Supply	BBB	Baa2	BBB	BBB-	Baa3	BBB-
AGC				BBB-	Baa3	BBB-
ATSI				BBB-	Baa1	
CEI	BBB	Baa1	BBB	BBB-	Baa3	BBB-
JCP&L				BBB-	Baa2	BBB+
Met-Ed	BBB	A3	BBB+	BBB-	Baa2	BBB
MP	BBB+	Baa1	BBB+	BBB-	Baa3	BBB-
OE	BBB	A3	BBB+	BBB-	Baa2	BBB
Penelec	BBB	A3	BBB+	BBB-	Baa2	BBB
Penn	BBB+	A3	BBB+			
PE	BBB+	Baa1	BBB+	BBB-	Baa3	BBB-

TE	BBB	Baa1	BBB			
TrAIL				BBB-	Baa2	BBB
WP	BBB+	A3	BBB+	BBB-	Baa2	BBB-

Changes in Cash Position

As of March 31, 2011, FirstEnergy had $1.1 billion of cash and cash equivalents compared to $1 billion as of December 31, 2010. As of March 31, 2011 and December 31, 2010, FirstEnergy had approximately $73 million and $13 million, respectively, of restricted cash included in other current assets on the Consolidated Balance Sheet.

During the first three months of 2011, FirstEnergy received $240 million of cash dividends from its subsidiaries and paid $190 million in cash dividends to common shareholders, including $20 million paid in March by Allegheny to its former shareholders.

Cash Flows From Operating Activities

FirstEnergy s consolidated net cash from operating activities is provided primarily by its competitive energy services and energy delivery services businesses (see Results of Operations above). Net cash provided from operating activities decreased by $15 million during the first three months of 2011 compared to the comparable period in 2010, as summarized in the following table:

Operating Cash Flows	**Three Months Ended March 31 2011**	**2010**	**Increase (Decrease)**
	(In millions)		
Net income	$ 45	$ 149	$ (104)
Non-cash charges and other adjustments	515	367	148
Pension trust contribution	(157)		(157)
Working capital and other	88	(10)	98
	$ 491	$ 506	$ (15)

The increase in non-cash charges and other adjustments is primarily due to increased deferred taxes and investment tax credits ($112 million), increased asset impairments ($19 million), changes in accrued compensation and retirement benefits ($68 million) and increased depreciation ($27 million), partially offset by lower amortization of regulatory assets ($80 million).

The increase in cash flows from working capital and other is primarily due to decreased receivables ($162 million), decreased prepayments and other current assets ($85 million) and decreased materials and supplies ($82 million), partially offset by decreased accrued taxes ($189 million) and decreased accounts payable ($33 million).

Cash Flows From Financing Activities

In the first three months of 2011, cash used for financing activities was $550 million compared to $594 million in the first three months of 2010. The following table summarizes security issuances (net of any discounts) and redemptions:

Securities Issued or Redeemed	**Three Months Ended March 31 2011**	**2010**
	(In millions)	
New Issues		
Pollution control notes	150	
Long-term revolvers	60	
Unsecured Notes	7	
	$ 217	$
Redemptions		
Pollution control notes	(200)	

Long-term revolvers		(20)		
Senior secured notes		(109)		9
Unsecured notes		(30)		100
	$	(359)	$	109
Short-term borrowings, net	$	(214)	$	(295)

On March 29, 2011, FES paid off a $100 million term loan secured by FMBs that was scheduled to mature on March 31, 2011. On April 8, 2011, FirstEnergy entered into a $150 million unsecured term loan with an April 2013 maturity.

In March 2011 FES repurchased and retired $20 million of its 6.80% unsecured senior notes and $10 million of its 6.05% unsecured senior notes originally outstanding in the principal amounts of $500 million and $600 million, respectively. Additionally, on April 29, 2011, Met-Ed redeemed approximately $14 million of FMBs securing PCRBs. During the remainder of 2011, FirstEnergy and its subsidiaries expect to pursue, from time to time, continued reductions in outstanding long-term debt of up to approximately $1.0 to $1.5 billion including through redemptions, open market or privately negotiated purchases. Any such transactions will be subject to prevailing market conditions, liquidity requirements and other factors.

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Cash Flows From Investing Activities

Cash flows received from investing activities in the first three months of 2011 resulted primarily from the cash acquired in the Allegheny merger, partially offset by cash used for property additions. The following table summarizes investing activities for the first three months of 2011 and 2010 by business segment:

Summary of Cash Flows Provided from (Used for) Investing Activities	Property Additions	Investments	Other	Total
		(In millions)		
Sources (Uses)				
Three Months Ended March 31, 2011				
Regulated distribution	$ (177)	$ 60	$ (9)	$ (126)
Competitive energy services	(214)	(15)	(8)	(237)
Regulated independent transmission	(27)	(1)		(28)
Other	(31)	590	145	704
Inter-Segment reconciling items		(22)	(150)	(172)
Total	$ (449)	$ 612	$ (22)	$ 141
Three Months Ended March 31, 2010				
Regulated distribution	$ (152)	$ 62	$ (6)	$ (96)
Competitive energy services	(329)		(1)	(330)
Regulated independent transmission	(14)		(1)	(15)
Other	(13)			(13)
Inter-Segment reconciling items		(22)		(22)
Total	$ (508)	$ 40	$ (8)	$ (476)

Net cash provided from investing activities in the first three months of 2011 increased by $617 million compared to the first three months of 2010. The increase was principally due to cash acquired in the Allegheny merger ($590 million), a decrease in purchases of customer intangibles by FES in the customer acquisition process ($100 million) and a decrease in property additions ($59 million), principally due to lower AQC system expenditures, partially offset by decreased proceeds from asset sales ($114 million).

During the remaining nine months of 2011, capital requirements for property additions and capital leases are expected to be approximately $1.8 billion. This includes approximately $90 million of nuclear fuel expenditures.

CONTRACTUAL OBLIGATIONS

Estimated cash payments for contractual obligations that are considered firm obligations acquired by FirstEnergy in the AE merger are summarized as follows:

Contractual Obligations	Total	2011	2012-2013	2014-2015	Thereafter
			(In millions)		
Long-term debt(1)	$ 4,776	$ 8	$ 1,445	$ 1,037	$ 2,286
Interest on long-term debt(2)	2,516	240	470	341	1,465
Fuel and purchased power(3)	9,781	956	2,160	1,650	5,015
Capital expenditures	141	117	24		
Pension funding (4)	695	124	175	186	210

Total	$ 17,909	$ 1,445	$ 4,274	$ 3,214	$ 8,976

(1) Does not include payments made and debt issued subsequent to March 31, 2011.

(2) Interest on variable-rate debt is based on interest rates as of March 31, 2011.

(3) Amounts under contract with fixed or minimum quantities are based on estimated annual requirements.

(4) Estimated contributions through 2021 based on current actuarial assumptions.

GUARANTEES AND OTHER ASSURANCES

As part of normal business activities, FirstEnergy enters into various agreements on behalf of its subsidiaries to provide financial or performance assurances to third parties. These agreements include contract guarantees, surety bonds and LOCs. Some of the guaranteed contracts contain collateral provisions that are contingent upon either FirstEnergy or its subsidiaries credit ratings.

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As of March 31, 2011, FirstEnergy s maximum exposure to potential future payments under outstanding guarantees and other assurances approximated $3.8 billion, as summarized below:

Guarantees and Other Assurances	Maximum Exposure (In millions)	
FirstEnergy Guarantees on Behalf of its Subsidiaries		
Energy and Energy-Related Contracts[(1)]	$	231
FirstEnergy guarantee of OVEC obligations		300
Other[(2)]		228
		759
Subsidiaries Guarantees		
Energy and Energy-Related Contracts		158
FES guarantee of NGC s nuclear property insurance		70
FES guarantee of FGCO s sale and leaseback obligations		2,375
Other		18
		2,621
Surety Bonds		138
LOC (non-debt)[(3)]		318
		456
Total Guarantees and Other Assurances	$	3,836

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

(2) Includes guarantees of $15 million for nuclear decommissioning funding assurances, $161 million supporting OE s sale and leaseback arrangement, and $37 million for railcar leases.

(3) Includes $146 million issued for various terms pursuant to LOC capacity available under FirstEnergy s revolving credit facilities, $130 million pledged in connection with the sale and leaseback of Beaver Valley Unit 2 by OE and $42 million pledged in connection with the sale and leaseback of Perry by OE.

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

While these types of guarantees are normally parental commitments for the future payment of subsidiary obligations, subsequent to the occurrence of a credit rating downgrade to below investment grade, an acceleration or funding obligation or a material adverse event, the immediate posting of cash collateral, provision of a LOC or accelerated payments may be required of the subsidiary. As of March 31, 2011, FirstEnergy s maximum exposure under these collateral provisions was $557 million, as shown below:

Collateral Provisions	**FES**	**AE Supply**	**Utilities**	**Total**
		(In millions)		
Credit rating downgrade to below investment grade [1]	$ 357	$ 10	$ 66	$ 433
Material adverse event [2]	54	57	13	124
Total	$ 411	$ 67	$ 79	$ 557

(1) Includes $138 million and $46 million that is also considered an acceleration of payment or funding obligation at FES and the Utilities, respectively.

(2) Includes $53 million that is also considered an acceleration of payment or funding obligation at FES.

Stress case conditions of a credit rating downgrade or material adverse event and hypothetical adverse price movements in the underlying commodity markets would increase the total potential amount to $623 million, as shown below:

Collateral Provisions	FES	AE Supply	Utilities	Total
		(In millions)		
Credit rating downgrade to below investment grade (1)	$ 420	$ 8	$ 66	$ 494
Material adverse event (2)	60	56	13	129
Total	$ 480	$ 64	$ 79	$ 623

(1) Includes $138 million and $46 million that is also considered an acceleration of payment or funding obligation at FES and the Utilities, respectively.

(2) Includes $53 million that is also considered an acceleration of payment or funding obligation at FES.

Most of FirstEnergy s surety bonds are backed by various indemnities common within the insurance industry. Surety bonds and related guarantees of $138 million provide additional assurance to outside parties that contractual and statutory obligations will be met in a number of areas including construction contracts, environmental commitments and various retail transactions.

In addition to guarantees and surety bonds, contracts entered into by the Competitive Energy Services segment, including power contracts with affiliates awarded through competitive bidding processes, typically contain margining provisions that require the posting of cash or LOCs in amounts determined by future power price movements. Based on FES and AE Supply s power portfolio as of March 31, 2011 and forward prices as of that date, FES and AE Supply have posted collateral of $158 million and $5 million, respectively. Under a hypothetical adverse change in forward prices (95% confidence level change in forward prices over a one year time horizon), FES would be required to post an additional $52 million of collateral. Depending on the volume of forward contracts and future price movements, higher amounts for margining could be required to be posted.

In connection with FES obligations to post and maintain collateral under the two-year PSA entered into by FES and the Ohio Companies following the CBP auction on May 13-14, 2009, NGC entered into a Surplus Margin Guaranty in an amount up to $500 million. The Surplus Margin Guaranty is secured by an NGC FMB issued in favor of the Ohio Companies.

FES debt obligations are generally guaranteed by its subsidiaries, FGCO and NGC, and FES guarantees the debt obligations of each of FGCO and NGC. Accordingly, present and future holders of indebtedness of FES, FGCO and NGC may have claims against each of FES, FGCO and NGC, regardless of whether their primary obligor is FES, FGCO or NGC.

Signal Peak and Global Rail are borrowers under a $350 million syndicated two-year senior secured term loan facility. FirstEnergy, together with WMB Loan Ventures LLC and WMB Loan Ventures II LLC, the entities that share ownership in the borrowers with FEV, have provided a guaranty of the borrowers obligations under the facility. In addition, FEV and the other entities that directly own the equity interest in the borrowers have pledged those interests to the lenders under the term loan facility as collateral for the facility.

OFF-BALANCE SHEET ARRANGEMENTS

FES and the Ohio Companies have obligations that are not included on their Consolidated Balance Sheets related to sale and leaseback arrangements involving the Bruce Mansfield Plant, Perry Unit 1 and Beaver Valley Unit 2, which are satisfied through operating lease payments. The total present value of these sale and leaseback operating lease commitments, net of trust investments, is $1.7 billion as of March 31, 2011.

MARKET RISK INFORMATION

FirstEnergy uses various market risk sensitive instruments, including derivative contracts, primarily to manage the risk of price and interest rate fluctuations. FirstEnergy s Risk Policy Committee, comprised of members of senior management, provides general oversight for risk management activities throughout the company.

Commodity Price Risk

FirstEnergy is exposed to financial risks resulting from fluctuating interest rates and commodity prices, including prices for electricity, natural gas, coal and energy transmission. To manage the volatility relating to these exposures, FirstEnergy established a Risk Policy Committee, comprised of members of senior management, which provides general management oversight for risk management activities throughout FirstEnergy. The Committee is responsible for promoting the effective design and implementation of sound risk management programs and oversees compliance with corporate risk management policies and established risk management practice. FirstEnergy uses a variety of derivative instruments for risk management purposes including forward contracts, options, futures contracts and swaps. In addition to derivatives, FirstEnergy also enters into master netting agreements with certain third parties.

The valuation of derivative contracts is based on observable market information to the extent that such information is available. In cases where such information is not available, FirstEnergy relies on model-based information. The model provides estimates of future regional prices for electricity and an estimate of related price volatility. FirstEnergy uses these results to develop estimates of fair value for financial reporting purposes and for internal management decision making (see Note 6 to the consolidated financial statements). Sources of information for the valuation of commodity derivative contracts as of March 31, 2011 are summarized by year in the following table:

Source of Information- Fair Value by Contract Year	**2011**	**2012**	**2013**	**2014**	**2015**	**Thereafter**	**Total**
				(In millions)			
Prices actively quoted[1]	$	$	$	$	$	$	$
Other external sources[2]	(315)	(152)	(44)	(36)			(547)
Prices based on models	(11)				19	106	114
Total[3]	$ (326)	$ (152)	$ (44)	$ (36)	$ 19	$ 106	$ (433)

(1) Represents exchange traded New York Mercantile Exchange futures and options.

(2) Primarily represents contracts based on broker and IntercontinentalExchange quotes.

(3) Includes $366 million in non-hedge commodity derivative contracts that are primarily related to NUG contracts. NUG contracts are generally subject to regulatory accounting and do not materially impact earnings.

FirstEnergy performs sensitivity analyses to estimate its exposure to the market risk of its commodity positions. Based on derivative contracts held as of March 31, 2011, an adverse 10% change in commodity prices would decrease net income by approximately $12 million ($7 million net of tax) during the next 12 months.

Equity Price Risk

FirstEnergy provides a noncontributory qualified defined benefit pension plan that covers substantially all of its employees other than Allegheny employees employed by FirstEnergy and non-qualified pension plans that cover certain employees (the FirstEnergy Pension Plan). In addition, effective on the date of the merger, FirstEnergy provides noncontributory qualified defined pension plan benefits that cover substantially all of Allegheny employees employed by FirstEnergy and a supplemental executive retirement plan that covers certain Allegheny executives employed by FirstEnergy (the Allegheny Pension Plan). The FirstEnergy Pension Plan and the Allegheny Pension Plan provide defined benefits based on years of service and compensation levels.

Eligible FirstEnergy retirees, their dependents and, under certain circumstances, their survivors are provided other postretirement benefits such as a minimum amount of noncontributory life insurance, optional contributory insurance and certain health care benefits. These other postretirement benefits are not provided in retirement for employees hired on or after January 1, 2005.

Eligible Allegheny retirees and dependents are provided other postretirement benefits such as subsidies for medical and life insurance plans. Subsidized medical coverage is not provided in retirement to Allegheny employees employed by FirstEnergy that were hired on or after January 1, 1993, with the exception of certain union employees who were hired or became members before May 1, 2006.

The benefit plan assets and obligations are remeasured annually using a December 31 measurement date or as significant triggering events occur. As of March 31, 2011, the FirstEnergy pension plan was invested in approximately 32% of equity securities, 47% of fixed income securities, 10% of absolute return strategies, 5% of real estate, 2% of private equity and 4% of cash. The FirstEnergy Pension Plan and the Allegheny Pension Plan were 86% and 78%, respectively, funded on an accumulated benefit obligation basis as of March 31, 2011. A decline in the value of pension plan assets could result in additional funding requirements. FirstEnergy s funding policy is based on actuarial computations using the projected unit credit method. During the first quarter of 2011, FirstEnergy made a $157 million contribution to its qualified pension plans. FirstEnergy intends to make additional contributions of

$220 million and $6 million to its qualified pension plans and postretirement benefit plans, respectively, in the last three quarters of 2011.

Nuclear decommissioning trust funds have been established to satisfy NGC s and the Utilities nuclear decommissioning obligations. As of March 31, 2011, approximately 85% of the funds were invested in fixed income securities, 9% of the funds were invested in equity securities and 6% were invested in short-term investments, with limitations related to concentration and investment grade ratings. The investments are carried at their market values of approximately $1,741 million, $194 million and $115 million for fixed income securities, equity securities and short-term investments, respectively, as of Mach 31, 2011, excluding $(31) million of receivables, payables, deferred taxes and accrued income. A hypothetical 10% decrease in prices quoted by stock exchanges would result in a $19 million reduction in fair value as of March 31, 2011. The decommissioning trusts of JCP&L and the Pennsylvania Companies are subject to regulatory accounting, with unrealized gains and losses recorded as regulatory assets or liabilities, since the difference between investments held in trust and the decommissioning liabilities will be recovered from or refunded to customers. NGC, OE and TE recognize in earnings the unrealized losses on available-for-sale securities held in their nuclear decommissioning trusts as other-than-temporary impairments. A decline in the value of FirstEnergy s nuclear decommissioning trusts or a significant escalation in estimated decommissioning costs could result in additional funding requirements. In the first three months of 2011, approximately $1 million was contributed to JCP&L s nuclear decommissioning trusts. During the second quarter of 2011, FirstEnergy intends to contribute approximately $4 million and $1 million to the OE and TE nuclear decommissioning trusts, respectively, to comply with requirements under certain sale-leaseback transactions in which OE and TE continue as lessees. On March 28, 2011, FENOC submitted its biennial report on nuclear decommissioning funding to the NRC. This submittal identified a total shortfall in nuclear decommissioning funding for Beaver Valley Unit 1 and Perry of approximately $93 million. This estimate encompasses the shortfall covered by the existing $15 million parental guarantee. FENOC agreed to increase the parental guarantee to $95 million within 90 days of the submittal.

CREDIT RISK

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

FirstEnergy maintains credit policies with respect to its counterparties to manage overall credit risk. This includes performing independent risk evaluations, actively monitoring portfolio trends and using collateral and contract provisions to mitigate exposure. As part of its credit program, FirstEnergy aggressively manages the quality of its portfolio of energy contracts, evidenced by a current weighted average risk rating for energy contract counterparties of BBB (S&P). As of March 31, 2011, the largest credit concentration was with J.P. Morgan Chase & Co., which is currently rated investment grade, representing 13.4% of FirstEnergy s total approved credit risk comprised of 5.9% for FES, 2.1% for JCP&L, 2.7% for Met-Ed and a combined 2.7% for OE, TE and CEI.

OUTLOOK

Reliability Initiatives

Federally-enforceable mandatory reliability standards apply to the bulk electric system and impose certain operating, record-keeping and reporting requirements on the Utilities, FES, FGCO, FENOC, and ATSI and TrAIL Company. The NERC, as the ERO is charged with establishing and enforcing these reliability standards, although it has delegated day-to-day implementation and enforcement of these reliability standards to eight regional entities, including Reliability*First* Corporation. All of FirstEnergy s facilities are located within the Reliability*First* region. FirstEnergy actively participates in the NERC and Reliability*First* stakeholder processes, and otherwise monitors and manages its companies in response to the ongoing development, implementation and enforcement of the reliability standards implemented and enforced by the Reliability*First* Corporation.

FirstEnergy believes that it generally is in compliance with all currently-effective and enforceable reliability standards. Nevertheless, in the course of operating its extensive electric utility systems and facilities, FirstEnergy occasionally learns of isolated facts or circumstances that could be interpreted as excursions from the reliability standards. If and when such items are found, FirstEnergy develops information about the item and develops a remedial response to the specific circumstances, including in appropriate cases self-reporting an item to Reliability*First*.

Moreover, it is clear that the NERC, Reliability*First* and the FERC will continue to refine existing reliability standards as well as to develop and adopt new reliability standards. The financial impact of complying with new or amended standards cannot be determined at this time; however, 2005 amendments to the FPA provide that all prudent costs incurred to comply with the new reliability standards be recovered in rates. Still, any future inability on FirstEnergy s part to comply with the reliability standards for its bulk power system could result in the imposition of financial penalties that could have a material adverse effect on its financial condition, results of operations and cash flows.

On December 9, 2008, a transformer at JCP&L s Oceanview substation failed, resulting in an outage on certain bulk electric system (transmission voltage) lines out of the Oceanview and Atlantic substations resulting in customers losing power for up to eleven hours. On March 31, 2009, the NERC initiated a Compliance Violation Investigation in order to determine JCP&L s contribution to the electrical event and to review any potential violation of NERC Reliability Standards associated with the event. NERC has submitted first and second Requests for Information regarding this and another related matter. JCP&L is complying with these requests. JCP&L is not able to predict what actions, if any, that the NERC may take with respect to this matter.

On August 23, 2010, FirstEnergy self-reported to Reliability*First* a vegetation encroachment event on a Met-Ed 230 kV line. This event did not result in a fault, outage, operation of protective equipment, or any other meaningful electric effect on any FirstEnergy transmission facilities or systems. On August 25, 2010, Reliability*First* issued a Notice of Enforcement to investigate the incident. FirstEnergy submitted a data response to Reliability*First* on September 27, 2010. In March 2011, Reliability*First* submitted its proposed findings and settlement. At this time, FirstEnergy is evaluating Reliability*First* s proposal and is unable to predict the final outcome of this investigation. Allegheny has been subject to routine audits with respect to its compliance with applicable reliability standards and has settled certain related issues. In addition, Reliability*First* is currently conducting certain violation investigations with regard to matters of compliance by Allegheny.

Maryland

In 1999, Maryland adopted electric industry restructuring legislation, which gave PE s Maryland retail electric customers the right to choose their electricity generation suppliers. PE remained obligated to provide standard offer generation service (SOS) at capped rates to residential and non-residential customers for various periods. The longest such period, for residential customers, expired on December 31, 2008. PE implemented a rate stabilization plan in 2007 that was designed to transition customers from capped generation rates to rates based on market prices and that concluded on December 31, 2010. PE s transmission and distribution rates for all customers are subject to traditional regulated utility ratemaking (i.e., cost-based rates).

By statute enacted in 2007, the obligation of Maryland utilities to provide SOS to residential and small commercial customers, in exchange for recovery of their costs plus a reasonable profit, was extended indefinitely. The legislation also established a five-year cycle (to begin in 2008) for the MDPSC to report to the legislature on the status of SOS. In August 2007, PE filed a plan for seeking bids to serve its Maryland residential load for the period after the expiration of rate caps. The MDPSC approved the plan and PE now conducts rolling auctions to procure the power supply necessary to serve its customer load. However, the terms on which PE will provide SOS to residential customers after the settlement beyond 2012 will depend on developments with respect to SOS in Maryland between now and then, including but not limited to possible MDPSC decisions in the proceedings discussed below.

The MDPSC opened a new docket in August 2007 to consider matters relating to possible managed portfolio approaches to SOS and other matters. Phase II of the case addressed utility purchases or construction of generation, bidding for procurement of demand response resources and possible alternatives if the TrAIL and PATH projects were delayed or defeated. It is unclear when the MDPSC will issue its findings in this and other SOS-related pending proceedings discussed below.

In September 2009, the MDPSC opened a new proceeding to receive and consider proposals for construction of new generation resources in Maryland. In December 2009, Governor Martin O Malley filed a letter in this proceeding in which he characterized the electricity market in Maryland as a failure and urged the MDPSC to use its existing authority to order the construction of new generation in Maryland, vary the means used by utilities to procure generation and include more renewables in the generation mix. In August 2010, the MDPSC opened another new proceeding to solicit comments on the PJM RPM process. Public hearings on the comments were held in October 2010. In December 2010, the MDPSC issued an order soliciting comments on a model request for proposal for solicitation of long-term energy commitments by Maryland electric utilities. PE and numerous other parties filed comments, and at this time no further proceedings have been set by the MDPSC in this matter.

In September 2007, the MDPSC issued an order that required the Maryland utilities to file detailed plans for how they will meet the EmPOWER Maryland proposal that, in Maryland, electric consumption be reduced by 10% and electricity demand be reduced by 15%, in each case by 2015. In October 2007, PE filed its initial report on energy efficiency, conservation and demand reduction plans in connection with this order. The MDPSC conducted hearings on PE s and other utilities plans in November 2007 and May 2008.

In a related development, the Maryland legislature in 2008 adopted a statute codifying the EmPOWER Maryland goals. In 2008, PE filed its comprehensive plans for attempting to achieve those goals, asking the MDPSC to approve programs for residential, commercial, industrial, and governmental customers, as well as a customer education program, and a pilot deployment of Advanced Utility Infrastructure (AUI) that Allegheny had previously tested in West Virginia. The MDPSC ultimately approved the programs in August 2009 after certain modifications had been made as required by the MDPSC, and approved cost recovery for the programs in October 2009. Expenditures were estimated to be approximately $101 million and would be recovered over the following six years. The AUI pilot was placed on a separate track to be re-examined after further discussion with the Staff of the MDPSC and other stakeholders. Meanwhile, extensive meetings with the MDPSC Staff and other stakeholders to discuss details of PE s plans for additional and improved programs for the period 2012-2014 began in April 2011.

In March 2009, the Maryland PSC issued an order suspending until further notice the right of all electric and gas utilities in the state to terminate service to residential customers for non-payment of bills. The MDPSC subsequently issued an order making various rule changes relating to terminations, payment plans, and customer deposits that make it more difficult for Maryland utilities to collect deposits or to terminate service for non-payment. PE and several other utilities filed requests for reconsideration of various parts of the order, which were denied. The MDPSC is continuing to conduct hearings and collect data on payment plan and related issues and has adopted a set of proposed regulations that expand the summer and winter severe weather termination moratoria when temperatures are very high or very low, from one day, as provided by statute, to three days on each occurrence.

On March 24, 2011, the MDPSC held an initial hearing to discuss possible new regulations relating to service interruptions, storm response, call center metrics, and related reliability standards. The proposed rules included provisions for civil penalties for non-compliance. Numerous parties filed comments on the proposed rules and participated in the hearing, with many noting issues of cost and practicality relating to implementation. Concurrently, the Maryland legislature is considering a bill addressing the same topics. The final bill passed on April 11, 2011, requires the MDPSC to promulgate rules by July 1, 2012 that address service interruptions, downed wire response, customer communication, vegetation management, equipment inspection, and annual reporting. In crafting the regulations, the MDPSC is directed to consider cost-effectiveness, and may adopt different standards for different utilities based on such factors as system design and existing infrastructure, geography, and customer density. Beginning in July 2013, the MDPSC is to assess each utility s compliance with the standards, and may assess penalties of up to $25,000 per day per violation. The MDPSC has ordered that a working group of utilities, regulators, and other interested stakeholders meet to address the topics of the proposed rules.

In December 2009, PE filed an application with the MDPSC for authorization to construct the Maryland portions of the PATH Project to be owned by PATH Allegheny Maryland Transmission Company, LLC, which is owned by Potomac Edison and PATH-Allegheny. On February 28, 2011, PE withdrew its application. See Transmission Expansion in the Federal Regulation and Rate Matters section for further discussion of this matter.

New Jersey

JCP&L is permitted to defer for future collection from customers the amounts by which its costs of supplying BGS to non-shopping customers, costs incurred under NUG agreements, and certain other stranded costs, exceed amounts collected through BGS and NUG rates and market sales of NUG energy and capacity. As of March 31, 2011, the accumulated deferred cost balance was a credit of approximately $102 million. To better align the recovery of expected costs, in July 2010, JCP&L filed a request to decrease the amount recovered for the costs incurred under the NUG agreements by $180 million annually, which the NJBPU approved, allowing the change in rates to become effective March 1, 2011.

In March 2009 and again in February 2010, JCP&L filed annual SBC Petitions with the NJBPU that included a requested zero level of recovery of TMI-2 decommissioning costs based on an updated TMI-2 decommissioning cost analysis dated January 2009 estimated at $736 million (in 2003 dollars). Both matters are currently pending before the NJBPU.

Ohio

The Ohio Companies operate under an ESP, which expires on May 31, 2011, that provides for generation supplied through a CBP. The ESP also allows the Ohio Companies to collect a delivery service improvement rider (Rider DSI) at an overall average rate of $0.002 per KWH for the period of April 1, 2009 through December 31, 2011. The Ohio Companies currently purchase generation at the average wholesale rate of a CBP conducted in May 2009. FES is one of the suppliers to the Ohio Companies through the May 2009 CBP. The PUCO approved a $136.6 million distribution rate increase for the Ohio Companies in January 2009, which went into effect on January 23, 2009 for OE ($68.9 million) and TE ($38.5 million) and on May 1, 2009 for CEI ($29.2 million).

In March 2010, the Ohio Companies filed an application for a new ESP, which the PUCO approved in August 2010, with certain modifications. The new ESP will go into effect on June 1, 2011 and conclude on May 31, 2014. The material terms of the new ESP include: a CBP similar to the one used in May 2009 and the one proposed on the October 2009 MRO filing (initial auctions held on October 20, 2010 and January 25, 2011); a load cap of no less than 80%, which also applies to tranches assigned post-auction; a 6% generation discount to certain low income customers provided by the Ohio Companies through a bilateral wholesale contract with FES; no increase in base distribution rates through May 31, 2014; and a new distribution rider, Delivery Capital Recovery Rider (Rider DCR), to recover a return of, and on, capital investments in the delivery system. Rider DCR substitutes for Rider DSI which terminates under the current ESP. The Ohio Companies also agreed not to recover from retail customers certain costs related to the companies integration into PJM for the longer of the five-year period from June 1, 2011 through May 31, 2015 or when the amount of costs avoided by customers for certain types of products totals $360 million dependent on the outcome of certain PJM proceedings, agreed to establish a $12 million fund to assist low income customers over the term of the ESP and agreed to additional matters related to energy efficiency and alternative energy requirements. Many of the existing riders approved in the previous ESP remain in effect, with some modifications. The new ESP resolved proceedings pending at the PUCO regarding corporate separation, elements of the smart grid proceeding and expenses related to the ESP.

Under the provisions of SB221, the Ohio Companies are required to implement energy efficiency programs that will achieve a total annual energy savings equivalent to approximately 166,000 MWH in 2009, 290,000 MWH in 2010, 410,000 MWH in 2011, 470,000 MWH in 2012 and 530,000 MWH in 2013, with additional savings required through 2025. Utilities are also required to reduce peak demand in 2009 by 1%, with an additional 0.75% reduction each year thereafter through 2018.

In December 2009, the Ohio Companies filed the required three year portfolio plan seeking approval for the programs they intend to implement to meet the energy efficiency and peak demand reduction requirements for the 2010-2012 period. The Ohio Companies expect that all costs associated with compliance will be recoverable from customers. The PUCO issued an Opinion and Order generally approving the Ohio Companies 3-year plan, and the Companies are in the process of implementing those programs included in the Plan. Because of the delay in issuing the Order, the launch of the programs included in the plan for 2010 was delayed and will launch during the second quarter of this year. As a result, OE fell short of its statutory 2010 energy efficiency and peak demand reduction benchmarks. Therefore, on January 11, 2011, it requested that its 2010 energy efficiency and peak demand reduction benchmarks be amended to actual levels achieved in 2010. Moreover, because the PUCO indicated, when approving the 2009 benchmark request, that it would modify the Companies 2010 (and 2011 and 2012) energy efficiency benchmarks when addressing the portfolio plan, the Ohio Companies were not certain of their 2010 energy efficiency obligations. Therefore, CEI and TE (each of which achieved its 2010 energy efficiency and peak demand reduction statutory benchmarks) also requested an amendment if and only to the degree one was deemed necessary to bring these them into compliance with their yet-to-be-defined modified benchmarks. Failure to comply with the benchmarks or to obtain such an amendment may subject the Companies to an assessment by the PUCO of a penalty. In addition to approving the programs included in the plan, with only minor modifications, the PUCO authorized the Companies to recover all costs related to the original CFL program that the Ohio Companies had previously suspended at the request of the PUCO. Applications for Rehearing were filed on April 22, 2011, regarding portions of the PUCO s decision, including the method for calculating savings and certain changes made by the PUCO to specific programs.

Additionally under SB221, electric utilities and electric service companies are required to serve part of their load from renewable energy resources equivalent to 0.25% of the KWH they served in 2009. In August and October 2009, the Ohio Companies conducted RFPs to secure RECs. The RFPs sought RECs, including solar RECs and RECs generated in Ohio in order to meet the Ohio Companies alternative energy requirements as set forth in SB221 for 2009, 2010 and 2011. The RECs acquired through these two RFPs were used to help meet the renewable energy requirements established under SB221 for 2009, 2010 and 2011. In March 2010, the PUCO found that there was an insufficient quantity of solar energy resources reasonably available in the market. The PUCO reduced the Ohio Companies aggregate 2009 benchmark to the level of solar RECs the Ohio Companies acquired through their 2009 RFP processes, provided the Ohio Companies 2010 alternative energy requirements be increased to include the shortfall for the 2009 solar REC benchmark. FES also applied for a force majeure determination from the PUCO regarding a portion of their compliance with the 2009 solar energy resource benchmark. On February 23, 2011, the PUCO granted FES force majeure request for 2009 and increased its 2010 benchmark by the amount of SRECs that FES was short of in its 2009 benchmark. In July 2010, the Ohio Companies initiated an additional RFP to secure RECs and solar RECs needed to meet the Ohio Companies alternative energy requirements as set forth in SB221 for 2010 and 2011 and executed related contracts in August 2010. On April 15, 2011, the Ohio Companies filed an application seeking an amendment to each of their 2010 alternative energy requirements for solar RECs generated in Ohio on the basis that an insufficient quantity of solar resources are available in the market but reflecting solar RECs that they have obtained and providing additional information regarding efforts to secure solar RECs. The PUCO has not yet acted on that application.

In February 2010, OE and CEI filed an application with the PUCO to establish a new credit for all-electric customers. In March 2010, the PUCO ordered that rates for the affected customers be set at a level that will provide bill impacts commensurate with charges in place on December 31, 2008 and authorized the Ohio Companies to defer incurred costs equivalent to the difference between what the affected customers would have paid under previously existing rates and what they pay with the new credit in place. Tariffs implementing this new credit went into effect in March 2010. In April 2010, the PUCO issued a Second Entry on Rehearing that expanded the group of customers to which the new credit would apply and authorized deferral for the associated additional amounts. The PUCO also stated that it expected that the new credit would remain in place through at least the 2011 winter season, and charged its staff to work with parties to seek a long term solution to the issue. Tariffs implementing this newly expanded credit went into effect in May 2010 and the proceeding remains open. The hearing on the matter was held in February 2011. The matter has now been briefed and the Ohio Companies await the PUCO s decision.

Pennsylvania

The PPUC entered an Order on March 3, 2010 that denied the recovery of marginal transmission losses through the TSC rider for the period of June 1, 2007 through March 31, 2008, directed Met-Ed and Penelec to submit a new tariff or tariff supplement reflecting the removal of marginal transmission losses from the TSC, and instructed Met-Ed and Penelec to work with the various intervening parties to file a recommendation to the PPUC regarding the establishment of a separate account for all marginal transmission losses collected from ratepayers plus interest to be used to mitigate future generation rate increases beginning January 1, 2011. In March 2010, Met-Ed and Penelec filed a Petition with the PPUC requesting that it stay the portion of the March 3, 2010 Order requiring the filing of tariff supplements to end collection of costs for marginal transmission losses. The PPUC granted the requested stay until December 31, 2010. Pursuant to the PPUC s order, Met-Ed and Penelec filed plans to establish separate accounts for marginal transmission loss revenues and related interest and carrying charges and for the use of these funds to mitigate future generation rate increases which the PPUC approved. In April 2010, Met-Ed and Penelec filed a Petition for Review with the Commonwealth Court of Pennsylvania appealing the PPUC s March 3, 2010 Order. The argument before the Commonwealth Court, en banc, was held in December 2010. Although the ultimate outcome of this matter cannot be determined at this time, Met-Ed and Penelec believe that they should prevail in the appeal and therefore expect to fully recover the approximately $252.7 million ($188.0 million for Met-Ed and $64.7 million for Penelec) in marginal transmission losses for the period prior to January 1, 2011.

In May 2008, May 2009 and May 2010, the PPUC approved Met-Ed s and Penelec s annual updates to their TSC rider for the annual periods between June 1, 2008 to December 31, 2010, including marginal transmission losses as approved by the PPUC, although the recovery of marginal losses will be subject to the outcome of the proceeding related to the 2008 TSC filing as described above. The PPUC s approval in May 2010 authorized an increase to the TSC for Met-Ed s customers to provide for full recovery by December 31, 2010.

Met-Ed and Penelec filed with the PPUC a generation procurement plan covering the period January 1, 2011 through May 31, 2013. The plan is designed to provide adequate and reliable service through a prudent mix of long-term, short-term and spot market generation supply with a staggered procurement schedule that varies by customer class, using a descending clock auction. In August 2009, the parties to the proceeding filed a settlement agreement of all but two issues, and the PPUC entered an Order approving the settlement and the generation procurement plan in November 2009. Generation procurement began in January 2010.

In February 2010, Penn filed a Petition for Approval of its Default Service Plan for the period June 1, 2011 through May 31, 2013. In July 2010, the parties to the proceeding filed a Joint Petition for Settlement of all issues. Although the PPUC s Order approving the Joint Petition held that the provisions relating to the recovery of MISO exit fees and one-time PJM integration costs (resulting from Penn s June 1, 2011 exit from MISO and integration into PJM) were approved, it made such provisions subject to the approval of cost recovery by FERC. Therefore, Penn may not put these provisions into effect until FERC has approved the recovery and allocation of MISO exit fees and PJM integration costs.

Pennsylvania adopted Act 129 in 2008 to address issues such as: energy efficiency and peak load reduction; generation procurement; time-of-use rates; smart meters; and alternative energy. Among other things, Act 129 required utilities to file with the PPUC an energy efficiency and peak load reduction plan, or EE&C Plan, by July 1, 2009, setting forth the utilities plans to reduce energy consumption by a minimum of 1% and 3% by May 31, 2011 and May 31, 2013, respectively, and to reduce peak demand by a minimum of 4.5% by May 31, 2013. Act 129 also required utilities to file with the PPUC a Smart Meter Implementation Plan (SMIP).

The PPUC entered an Order in February 2010 giving final approval to all aspects of the EE&C Plans of Met-Ed, Penelec and Penn and the tariff rider with rates effective March 1, 2010.

WP filed its original EE&C Plan in June 2009, which the PPUC approved, in large part, by Opinion and Order entered in October 2009. In November 2009, the Office of Consumer Advocate (OCA) filed an appeal with the Commonwealth Court of the PPUC s October Order. The OCA contends that the PPUC s Order failed to include WP s costs for smart meter implementation in the EE&C Plan, and that inclusion of such costs would cause the EE&C Plan to exceed the statutory cap for EE&C expenditures. The OCA also contends that WP s EE&C plan does not meet the Total Resource Cost Test. The appeal remains pending but has been stayed by the Commonwealth Court pending possible settlement of WP s SMIP. In September, 2010, WP filed an amended EE&C Plan that is less reliant on smart meter deployment, which the PPUC approved in January 2011.

Met-Ed, Penelec and Penn jointly filed a SMIP with the PPUC in August 2009. This plan proposed a 24-month assessment period in which the Pennsylvania Companies will assess their needs, select the necessary technology, secure vendors, train personnel, install and test support equipment, and establish a cost effective and strategic deployment schedule, which currently is expected to be completed in fifteen years. Met-Ed, Penelec and Penn estimate assessment period costs of approximately $29.5 million, which the Pennsylvania Companies, in their plan, proposed to recover through an automatic adjustment clause. The ALJ s Initial Decision approved the SMIP as modified by the ALJ, including: ensuring that the smart meters to be deployed include the capabilities listed in the PPUC s Implementation Order; denying the recovery of interest through the automatic adjustment clause; providing for the recovery of reasonable and prudent costs net of resulting savings from installation and use of smart meters; and requiring that administrative start-up costs be expensed and the costs incurred for research and development in the assessment period be capitalized. In April 2010, the PPUC adopted a Motion by Chairman Cawley that modified the ALJ s initial decision, and decided various issues regarding the SMIP for Met-Ed, Penelec and Penn. The PPUC entered its Order in June 2010, consistent with the Chairman s Motion. Met-Ed, Penelec and Penn filed a Petition for Reconsideration of a single portion of the PPUC s Order regarding the future ability to include smart meter costs in base rates, which the PPUC granted in part by deleting language from its original order that would have precluded Met-Ed, Penelec and Penn from seeking to include smart meter costs in base rates at a later time. The costs to implement the SMIP could be material. However, assuming these costs satisfy a just and reasonable standard, they are expected to be recovered in a rider (Smart Meter Technologies Charge Rider) which was approved when the PPUC approved the SMIP.

In August 2009, WP filed its original SMIP, which provided for extensive deployment of smart meter infrastructure with replacement of all of WP s approximately 725,000 meters by the end of 2014. In December 2009, WP filed a motion to reopen the evidentiary record to submit an alternative smart meter plan proposing, among other things, a less-rapid deployment of smart meters. In an Initial Decision dated April 29, 2010, an ALJ determined that WP s alternative smart meter deployment plan, which contemplated deployment of 375,000 smart meters by May 2012, complied with the requirements of Act 129 and recommended approval of the alternative plan, including WP s proposed cost recovery mechanism.

In light of the significant expenditures that would be associated with its smart meter deployment plans and related infrastructure upgrades, as well as its evaluation of recent PPUC decisions approving less-rapid deployment proposals by other utilities, WP re-evaluated its Act 129 compliance strategy, including both its plans with respect to smart meter deployment and certain smart meter dependent aspects of the EE&C Plan. In October 2010, WP and Pennsylvania s Office of Consumer Advocate filed a Joint Petition for Settlement addressing WP s smart meter implementation plan with the PPUC. Under the terms of the proposed settlement, WP proposed to decelerate its previously contemplated smart meter deployment schedule and to target the installation of approximately 25,000 smart meters in support of its EE&C Plan, based on customer requests, by mid-2012. The proposed settlement also contemplates that WP take advantage of the 30-month grace period authorized by the PPUC to continue WP s efforts to re-evaluate full-scale smart meter deployment plans. WP currently anticipates filing its plan for full-scale deployment of smart meters in June 2012. Under the terms of the proposed settlement, WP would be permitted to recover certain previously incurred and anticipated smart-meter related expenditures through a levelized customer surcharge, with certain expenditures amortized over a ten-year period. Additionally, WP would be permitted to seek recovery of certain other costs as part of its revised SMIP that it currently intends to file in June 2012, or in a future base distribution rate case.

In December 2010, the PPUC directed that the SMIP proceeding be referred to the ALJ for further proceedings to ensure that the impact of the proposed merger with FirstEnergy is considered and that the Joint Petition for Settlement has adequate support in the record. On March 9, 2011, WP submitted an Amended Joint Petition for Settlement which restates the Joint Petition for Settlement filed in October 2010, adds the PPUC s Office of Trial Staff as a signatory party, and confirms the support or non-opposition of all parties to the settlement. The proposed settlement also obligates OCA to withdraw its November 2009 appeal of the PPUC s Order in WP s EE&C plan proceeding. A Joint Stipulation with the OSBA was also filed on March 9, 2011. The proposed settlement remains subject to review by the ALJ, who will prepare an Initial Decision for consideration by the PPUC.

By Tentative Order entered in September 2009, the PPUC provided for an additional 30-day comment period on whether the 1998 Restructuring Settlement, which addressed how Met-Ed and Penelec were going to implement direct access to a competitive market for the generation of electricity, allows Met-Ed and Penelec to apply over-collection of NUG costs for select and isolated months to reduce non-NUG stranded costs when a cumulative NUG stranded cost balance exists. In response to the Tentative Order, various parties filed comments objecting to the above accounting method utilized by Met-Ed and Penelec. Met-Ed and Penelec are awaiting further action by the PPUC.

In the PPUC Order approving the FirstEnergy and Allegheny merger, the PPUC announced that a separate statewide investigation into Pennsylvania s retail electricity market will be conducted with the goal of making recommendations for improvements to ensure that a properly functioning and workable competitive retail electricity market exists in the state. The PPUC has not yet initiated that investigation.

Virginia

In September 2010, PATH-VA filed an application with the Virginia SCC for authorization to construct the Virginia portions of the PATH Project. On February 28, 2011, PATH-VA filed a motion to withdraw the application. See Transmission Expansion in the Federal Regulation and Rate Matters section for further discussion of this matter.

West Virginia

In August 2009, MP and PE filed with the WVPSC a request to increase retail rates by approximately $122.1 million annually, effective June 10, 2010. In January 2010, MP and PE filed supplemental testimony discussing a tax treatment change that would result in a revenue requirement approximately $7.7 million lower than the requirement included in the original filing. In addition, in December 2009, subsidiaries of MP and PE completed a securitization transaction to finance certain costs associated with the installation of scrubbers at the Fort Martin generating station, which costs would otherwise have been included in the request for rate recovery. Consequently, MP and PE ultimately requested an annual increase in retail rates of approximately $95 million, rather than $122.1 million. In April 2010, MP and PE filed with the WVPSC a Joint Stipulation and Agreement of Settlement reached with the other parties in the proceeding that provided for:

- a $40 million annualized base rate increase effective June 29, 2010;
- a deferral of February 2010 storm restoration expenses in West Virginia over a maximum five-year period;
- an additional $20 million annualized base rate increase effective in January 2011;
- a decrease of $20 million in ENEC rates effective January 2011, which amount is deferred for later recovery in 2012; and
- a moratorium on filing for further increases in base rates before December 1, 2011, except under specified circumstances.

The WVPSC approved the Joint Petition and Agreement of Settlement in June 2010.

In 2009, the West Virginia Legislature enacted the Alternative and Renewable Energy Portfolio Act (Portfolio Act), which generally requires that a specified minimum percentage of electricity sold to retail customers in West Virginia by electric utilities each year be derived from alternative and renewable energy resources according to a predetermined schedule of increasing percentage targets, including ten percent by 2015, fifteen percent by 2020, and twenty-five percent by 2025. In November 2010, the WVPSC issued Rules Governing Alternative and Renewable Energy Portfolio Standard (RPS Rules), which became effective on January 4, 2011. Under the RPS Rules, on or before January 1, 2011, each electric utility subject to the provisions of this rule was required to prepare an alternative and renewable energy portfolio standard compliance plan and file an application with the WVPSC seeking approval of such plan. MP and PE filed their combined compliance plan in December 2010. Additionally, in January 2011, MP and PE filed an application with the WVPSC seeking to certify three facilities as Qualified Energy Resource Facilities. If the application is approved, the three facilities would then be capable of generating renewable credits which would assist the Companies in meeting their combined requirements under the Portfolio Act. Further, in February 2011, MP and PE filed a petition with the WVPSC seeking an Order declaring that MP is entitled to all alternative & renewable energy resource credits associated with the electric energy, or energy and capacity, that MP is required to purchase pursuant to electric energy purchase agreements between MP and three non-utility electric generating facilities in WV. The City of New Martinsville, the owner of one of the contracted resources, has filed an opposition to the Petition.

FERC Matters

Rates for Transmission Service Between MISO and PJM

In November 2004, the FERC issued an order eliminating the through and out rate for transmission service between the MISO and PJM regions. The FERC s intent was to eliminate multiple transmission charges for a single transaction between the MISO and PJM regions. The FERC also ordered MISO, PJM and the transmission owners within MISO and PJM to submit compliance filings containing a rate mechanism to recover lost transmission revenues created by elimination of this charge (referred to as SECA) during a 16-month transition period. In 2005, the FERC set the SECA for hearing. The presiding ALJ issued an initial decision in August 2006, rejecting the compliance filings made by MISO, PJM and the transmission owners, and directing new compliance filings. This decision was subject to review and approval by the FERC. In May 2010, FERC issued an order denying pending rehearing requests and an Order on

Initial Decision which reversed the presiding ALJ s rulings in many respects. Most notably, these orders affirmed the right of transmission owners to collect SECA charges with adjustments that modestly reduce the level of such charges, and changes to the entities deemed responsible for payment of the SECA charges. The Ohio Companies were identified as load serving entities responsible for payment of additional SECA charges for a portion of the SECA period (Green Mountain/Quest issue). FirstEnergy executed settlements with AEP, Dayton and the Exelon parties to fix FirstEnergy s liability for SECA charges originally billed to Green Mountain and Quest for load that returned to regulated service during the SECA period. The AEP, Dayton and Exelon, settlements were approved by the FERC in November 2010, and the relevant payments made. The Utilities have refund obligations that are under review by FERC as part of a compliance filing. Potential refund obligations of FirstEnergy are not expected to be material. Rehearings remain pending in this proceeding.

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PJM Transmission Rate

In April 2007, FERC issued an order (Opinion 494) finding that the PJM transmission owners existing license plate or zonal rate design was just and reasonable and ordered that the current license plate rates for existing transmission facilities be retained. On the issue of rates for new transmission facilities, FERC directed that costs for new transmission facilities that are rated at 500 kV or higher are to be collected from all transmission zones throughout the PJM footprint by means of a postage-stamp rate based on the amount of load served in a transmission zone. Costs for new transmission facilities that are rated at less than 500 kV, however, are to be allocated on a load flow methodology (DFAX), which is generally referred to as a beneficiary pays approach to allocating the cost of high voltage transmission facilities.

The FERC s Opinion 494 order was appealed to the U.S. Court of Appeals for the Seventh Circuit, which issued a decision in August 2009. The court affirmed FERC s ratemaking treatment for existing transmission facilities, but found that FERC had not supported its decision to allocate costs for new 500+ kV facilities on a load ratio share basis and, based on this finding, remanded the rate design issue back to FERC.

In an order dated January 21, 2010, FERC set the matter for paper hearings meaning that FERC called for parties to submit comments or written testimony pursuant to the schedule described in the order. FERC identified nine separate issues for comments and directed PJM to file the first round of comments on February 22, 2010, with other parties submitting responsive comments and then reply comments on later dates. PJM filed certain studies with FERC on April 13, 2010, in response to the FERC order. PJM s filing demonstrated that allocation of the cost of high voltage transmission facilities on a beneficiary pays basis results in certain eastern utilities in PJM bearing the majority of the costs. Numerous parties filed responsive comments or studies on May 28, 2010 and reply comments on June 28, 2010. FirstEnergy and a number of other utilities, industrial customers and state commissions supported the use of the beneficiary pays approach for cost allocation for high voltage transmission facilities. Certain eastern utilities and their state commissions supported continued socialization of these costs on a load ratio share basis. This matter is awaiting action by the FERC.

RTO Realignment

On February 1, 2011, ATSI in conjunction with PJM filed its proposal with FERC for moving its transmission rate into PJM s tariffs. FirstEnergy expects ATSI to enter PJM on June 1, 2011, and that if legal proceedings regarding its rate are outstanding at that time, ATSI will be permitted to start charging its proposed rates, subject to refund. On April 1, 2011, the MISO Transmission Owners (including ATSI) filed proposed tariff language that describes the mechanics of collecting and administering MTEP costs from ATSI-zone ratepayers. From March 20, 2011 through April 1, 2011, FirstEnergy, PJM and the MISO submitted numerous filings for the purpose of effecting movement of the ATSI zone to PJM on June 1, 2011. These filings include clean-up of the MISO s tariffs (to remove the ATSI zone), submission of load and generation interconnection agreements to reflect the move into PJM, and submission of changes to PJM s tariffs to support the move into PJM.

FERC proceedings are pending in which ATSI s transmission rate, the exit fee payable to MISO, transmission cost allocations and costs associated with long term firm transmission rights payable by the ATSI zone upon its departure from the MISO are under review. The outcome of these proceedings cannot be predicted.

MISO Multi-Value Project Rule Proposal

In July 2010, MISO and certain MISO transmission owners jointly filed with FERC their proposed cost allocation methodology for certain new transmission projects. The new transmission projects described as MVPs are a class of MTEP projects. The filing parties proposed to allocate the costs of MVPs by means of a usage-based charge that will be applied to all loads within the MISO footprint, and to energy transactions that call for power to be wheeled through the MISO as well as to energy transactions that source in the MISO but sink outside of MISO. The filing parties expect that the MVP proposal will fund the costs of large transmission projects designed to bring wind generation from the upper Midwest to load centers in the east. The filing parties requested an effective date for the proposal of July 16, 2011. On August 19, 2010, MISO s Board approved the first MVP project the Michigan Thumb Project. Under MISO s proposal, the costs of MVP projects approved by MISO s Board prior to the anticipated June 1, 2011 effective date of FirstEnergy s integration into PJM would continue to be allocated to FirstEnergy. MISO estimated that approximately $15 million in annual revenue requirements would be allocated to the ATSI zone associated with the Michigan Thumb Project upon its completion.

In September 2010, FirstEnergy filed a protest to the MVP proposal arguing that MISO s proposal to allocate costs of MVP projects across the entire MISO footprint does not align with the established rule that cost allocation is to be based on cost causation (the beneficiary pays approach). FirstEnergy also argued that, in light of progress to date in the ATSI integration into PJM, it would be unjust and unreasonable to allocate any MVP costs to the ATSI zone, or to ATSI. Numerous other parties filed pleadings on MISO s MVP proposal.

In December 2010, FERC issued an order approving the MVP proposal without significant change. FERC s order was not clear, however, as to whether the MVP costs would be payable by ATSI or load in the ATSI zone. FERC stated that the MISO s tariffs obligate ATSI to pay all charges that attach prior to ATSI s exit but ruled that the question of the amount of costs that are to be allocated to ATSI or to load in the ATSI zone were beyond the scope of FERC s order and would be addressed in future proceedings.

On January 18, 2011, FirstEnergy filed for rehearing of FERC s order. In its rehearing request, FirstEnergy argued that because the MVP rate is usage-based, costs could not be applied to ATSI, which is a stand-alone transmission company that does not use the transmission system. FirstEnergy also renewed its arguments regarding cost causation and the impropriety of allocating costs to the ATSI zone or to ATSI. FirstEnergy cannot predict the outcome of these proceedings at this time.

PJM Calculation Error

In March 2010, MISO filed two complaints at FERC against PJM relating to a previously-reported modeling error in PJM s system that impacted the manner in which market-to-market power flow calculations were made between PJM and MISO since April 2005. MISO claimed that this error resulted in PJM underpaying MISO by approximately $130 million over the time period in question. Additionally, MISO alleged that PJM did not properly trigger market-to-market settlements between PJM and MISO during times when it was required to do so, which MISO claimed may have cost it $5 million or more. As PJM market participants, AE Supply and MP may be liable for a portion of any refunds ordered in this case. PJM, Allegheny and other PJM market participants filed responses to MISO complaints and PJM filed a related complaint at FERC against MISO claiming that MISO improperly called for market-to-market settlements several times during the same time period covered by the two MISO complaints filed against PJM, which PJM claimed may have cost PJM market participants $25 million or more. On January 4, 2011, an Offer of Settlement was filed at FERC that, if approved, would resolve all pending issues in the dispute. The Offer of Settlement calls for the withdrawal of all pending complaints with no payments being made by any parties. Initial comments on the Offer of Settlement were filed at FERC on January 24, 2011. FirstEnergy and Allegheny Energy filed comments supporting the proposed settlement. A report on the partially contested settlement was issued by the settlement judge to the FERC on March 9, 2011. On March 16, 2011, the settlement judge terminated the settlement proceedings and forwarded the partially contested settlement to the FERC for review. The case is awaiting a decision by the FERC.

California Claims Matters

In October 2006, several California governmental and utility parties presented AE Supply with a settlement proposal to resolve alleged overcharges for power sales by AE Supply to the California Energy Resource Scheduling division of the California Department of Water Resources (CDWR) during 2001. The settlement proposal claims that CDWR is owed approximately $190 million for these alleged overcharges. This proposal was made in the context of mediation efforts by the FERC and the United States Court of Appeals for the Ninth Circuit in pending proceedings to resolve all outstanding refund and other claims, including claims of alleged price manipulation in the California energy markets during 2000 and 2001. The Ninth Circuit has since remanded one of those proceedings to the FERC, which arises out of claims previously filed with the FERC by the California Attorney General on behalf of certain California parties against various sellers in the California wholesale power market, including AE Supply (the Lockyer case). AE Supply and several other sellers have filed motions to dismiss the Lockyer case. In March 2010, the judge assigned to the case entered an opinion that granted the motions to dismiss filed by AE Supply and other sellers and dismissed the claims of the California Parties. In April 2010, the California parties filed exceptions to the judge s ruling with the FERC, and briefing is complete on those exceptions. The parties are awaiting a ruling from the FERC on the exceptions.

In June 2009, the California Attorney General, on behalf of certain California parties, filed a second lawsuit with the FERC against various sellers, including AE Supply (the Brown case), again seeking refunds for trades in the California energy markets during 2000 and 2001. The above-noted trades with CDWR are the basis for the joining of AE Supply in this new lawsuit. AE Supply has filed a motion to dismiss the Brown case that is pending before the FERC. No scheduling order has been entered in the Brown case. Allegheny intends to vigorously defend against these claims but cannot predict their outcome.

Transmission Expansion

TrAIL Project. TrAIL is a 500 kV transmission line currently under construction that will extend from southwest Pennsylvania through West Virginia and into northern Virginia. On April 15, 2011, the TrAIL 500 kV line segment from Meadowbrook substation to Loudoun substation in Virginia was successfully energized and is carrying load. The other segments are planned to be energized in May. The entire TrAIL line is scheduled to be completed and placed in service no later than June 2011.

PATH Project. The PATH Project is comprised of a 765 kV transmission line that is proposed to extend from West Virginia through Virginia and into Maryland, modifications to an existing substation in Putnam County, West Virginia, and the construction of new substations in Hardy County, West Virginia and Frederick County, Maryland.

PJM initially authorized construction of the PATH Project in June 2007 and, on June 17, 2010, requested that PATH, LLC proceed with all efforts related to the PATH Project, including state regulatory proceedings, assuming a required in-service date of June 1, 2015. In December 2010, PJM advised that its 2011 Load Forecast Report included load projections that are different from previous forecasts and that may have an impact on the proposed in-service date for the PATH Project. As part of its 2011 RTEP, and in response to a January 19, 2011 directive by a Virginia Hearing Examiner, PJM conducted a series of analyses using the most current economic forecasts and demand response commitments, as well as potential new generation resources. Preliminary analysis revealed the expected reliability violations that necessitated the PATH Project had moved several years into the future. Based on those results, PJM announced on February 28, 2011 that its Board of Managers had decided to hold the PATH Project in abeyance in its 2011 RTEP and directed FirstEnergy and AEP, as the sponsoring transmission owners, to suspend current development efforts on the project, subject to those activities necessary to maintain the project in its current state, while PJM conducts more rigorous analysis of the potential need for the project as part of its continuing RTEP process. PJM stated that its action did not constitute a directive to FirstEnergy and AEP to cancel or abandon the PATH Project. PJM further stated that it will complete a more rigorous analysis of the PATH Project and other transmission requirements and its Board will review this comprehensive analysis as part of its consideration of the 2011 RTEP. On February 28, 2011, affiliates of FirstEnergy and AEP filed motions or notices to withdraw applications for authorization to construct the project that were pending before state commissions in West Virginia, Virginia and Maryland. Withdrawal was deemed effective upon filing the notice with the MDPSC and the WVPSC has granted the motion to withdraw. The VSCC has not ruled on the motion to withdraw.

PATH, LLC submitted a filing to FERC to implement a formula rate tariff effective March 1, 2008. In a November 19, 2010 order addressing various matters relating to the formula rate, FERC set the project s base return on equity for hearing and reaffirmed its prior authorization of a return on CWIP, recovery of start-up costs and recovery of abandonment costs. In the order, FERC also granted a 1.5% return on equity incentive adder and a 0.50% return on equity adder for RTO participation. These adders will be applied to the base return on equity determined as a result of the hearing. PATH, LLC is currently engaged in settlement discussions with the staff of FERC and intervenors regarding resolution of the base return on equity. FirstEnergy cannot predict the outcome of this proceeding or whether it will have a material impact on its operating results.

Sales to Affiliates

FES has received authorization from the FERC to make wholesale power sales to affiliated regulated utilities in New Jersey, Ohio, and Pennsylvania. FES actively participates in auctions conducted by or on behalf the regulated affiliates to obtain power necessary to meet the utilities POLR obligations. AE Supply, a merchant affiliate acquired in the FirstEnergy-Allegheny merger, also participates in these auctions, and obtains prior FERC authorization when necessary to make sales to FE affiliates.

Environmental Matters

Various federal, state and local authorities regulate FirstEnergy with regard to air and water quality and other environmental matters. Compliance with environmental regulations could have a material adverse effect on FirstEnergy s earnings and competitive position to the extent that FirstEnergy 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.

CAA Compliance

FirstEnergy is required to meet federally-approved SO_2 and NOx emissions regulations under the CAA. FirstEnergy complies with SO_2 and NOx reduction requirements under the CAA and SIP(s) by burning lower-sulfur fuel, combustion controls and post-combustion controls, generating more electricity from lower-emitting plants and/or using emission allowances. Violations can result in the shutdown of the generating unit involved and/or civil or criminal penalties.

The Sammis, Eastlake and Mansfield coal-fired plants are operated under a consent decree with the EPA and DOJ that requires reductions of NOx and SO_2 emissions through the installation of pollution control devices or repowering. OE and Penn are subject to stipulated penalties for failure to install and operate such pollution controls in accordance with that agreement.

In July 2008, three complaints were filed against FGCO in the U.S. District Court for the Western District of Pennsylvania seeking damages based on Bruce Mansfield Plant air emissions. Two of these complaints also seek to enjoin the Bruce Mansfield Plant from operating except in a safe, responsible, prudent and proper manner one being a complaint filed on behalf of twenty-one individuals and the other being a class action complaint seeking certification as a class action with the eight named plaintiffs as the class representatives. FGCO believes the claims are without merit and intends to defend itself against the allegations made in these three complaints.

The states of New Jersey and Connecticut filed CAA citizen suits in 2007 alleging NSR violations at the Portland Generation Station against GenOn Energy, Inc. (formerly RRI Energy, Inc. and the current owner and operator), Sithe Energy (the purchaser of the Portland Station from Met-Ed in 1999) and Met-Ed. Specifically, these suits allege that modifications at Portland Units 1 and 2 occurred between 1980 and 2005 without preconstruction NSR permitting in violation of the CAA s PSD program, and seek injunctive relief, penalties, attorney fees and mitigation of the harm caused by excess emissions. In September 2009, the Court granted Met-Ed s motion to dismiss New Jersey s and Connecticut s claims for injunctive relief against Met-Ed, but denied Met-Ed s motion to dismiss the claims for civil penalties. The parties dispute the scope of Met-Ed s indemnity obligation to and from Sithe Energy, and Met-Ed is unable to predict the outcome of this matter.

In January 2009, the EPA issued a NOV to GenOn Energy, Inc. alleging NSR violations at the Portland Generation Station based on modifications dating back to 1986 and also alleged NSR violations at the Keystone and Shawville Stations based on modifications dating back to 1984. Met-Ed, JCP&L, as the former owner of 16.67% of the Keystone Station, and Penelec, as former owner and operator of the Shawville Station, are unable to predict the outcome of this matter.

In June 2008, the EPA issued a Notice and Finding of Violation to Mission Energy Westside, Inc. (Mission) alleging that modifications at the Homer City Power Station occurred from 1988 to the present without preconstruction NSR permitting in violation of the CAA s PSD program. In May 2010, the EPA issued a second NOV to Mission, Penelec, New York State Electric & Gas Corporation and others that have had an ownership interest in the Homer City Power Station containing in all material respects allegations identical to those included in the June 2008 NOV. On July 20, 2010, the states of New York and Pennsylvania provided Mission, Penelec, NYSEG and others that have had an ownership interest in the Homer City Power Station a notification that was required 60 days prior to filing a citizen suit under the CAA. In January 2011, the DOJ filed a complaint against Penelec in the U.S. District Court for the Western District of Pennsylvania seeking injunctive relief against Penelec based on alleged modifications at the Homer City Power Station between 1991 to 1994 without preconstruction NSR permitting in violation of the CAA s PSD and Title V permitting programs. The complaint was also filed against the former co-owner, New York State Electric and Gas Corporation, and various current owners of the Homer City Station, including EME Homer City Generation L.P. and affiliated companies, including Edison International. In January 2011, another complaint was filed against Penelec and the other entities described above in the U.S. District Court for the Western District of Pennsylvania seeking damages based on the Homer City Station s air emissions as well as certification as a class action and to enjoin the Homer City Station from operating except in a safe, responsible, prudent and proper manner. Penelec believes the claims are without merit and intends to defend itself against the allegations made in the complaint, but, at this time, is unable to predict the outcome of this matter. In addition, the Commonwealth of Pennsylvania and the States of New Jersey and New York intervened and have filed separate complaints regarding the Homer City Station seeking injunctive relief and civil penalties. Mission is seeking indemnification from Penelec, the co-owner and operator of the Homer City Power Station prior to its sale in 1999. The scope of Penelec s indemnity obligation to and from Mission is under dispute and Penelec is unable to predict the outcome of this matter.

In August 2009, the EPA issued a Finding of Violation and NOV alleging violations of the CAA and Ohio regulations, including the PSD, NNSR and Title V regulations at the Eastlake, Lakeshore, Bay Shore and Ashtabula generating plants. The EPA s NOV alleges equipment replacements occurring during maintenance outages dating back to 1990 triggered the pre-construction permitting requirements under the PSD and NNSR programs. FGCO received a request for certain operating and maintenance information and planning information for these same generating plants and notification that the EPA is evaluating whether certain maintenance at the Eastlake generating plant may constitute a major modification under the NSR provision of the CAA. Later in 2009, FGCO also received another information request regarding emission projections for the Eastlake generating plant. FGCO intends to comply with the CAA, including the EPA s information requests but, at this time, is unable to predict the outcome of this matter.

In August 2000, AE received a letter from the EPA requesting that it provide information and documentation relevant to the operation and maintenance of the following ten electric generation facilities, which collectively include 22 generation units: Albright, Armstrong, Fort Martin, Harrison, Hatfield s Ferry, Mitchell, Pleasants, Rivesville, R. Paul Smith and Willow Island. The letter requested information under Section 114 of the CAA to determine compliance with the CAA and related requirements, including potential application of the NSR standards under the CAA, which can require the installation of additional air emission control equipment when the major modification of an existing facility results in an increase in emissions. AE has provided responsive information to this and a subsequent request but is unable to predict the outcome of this matter.

In May 2004, AE, AE Supply, MP and WP received a Notice of Intent to Sue Pursuant to CAA §7604 from the Attorneys General of New York, New Jersey and Connecticut and from the PA DEP, alleging that Allegheny performed major modifications in violation of the PSD provisions of the CAA at the following West Virginia coal-fired facilities: Albright Unit 3; Fort Martin Units 1 and 2; Harrison Units 1, 2 and 3; Pleasants Units 1 and 2 and Willow Island Unit 2. The Notice also alleged PSD violations at the Armstrong, Hatfield s Ferry and Mitchell generation facilities in Pennsylvania and identifies PA DEP as the lead agency regarding those facilities. In September 2004, AE, AE Supply, MP and WP received a separate Notice of Intent to Sue from the Maryland Attorney General that essentially mirrored the previous Notice.

In June 2005, the PA DEP and the Attorneys General of New York, New Jersey, Connecticut and Maryland filed suit against AE, AE Supply, MP, PE and WP in the United States District Court for the Western District of Pennsylvania alleging, among other things, that Allegheny performed major modifications in violation of the CAA and the Pennsylvania Air Pollution Control Act at the Hatfield s Ferry, Armstrong and Mitchell facilities in Pennsylvania. On January 17, 2006, the PA DEP and the Attorneys General filed an amended complaint. In May 2006, the District Court denied Allegheny s motion to dismiss the amended complaint. In July 2006, the Court determined that discovery would proceed regarding liability issues, but not remedies. Discovery on the liability phase closed on December 31, 2007, and summary judgment briefing was completed during the first quarter of 2008. In November 2008, the District Court issued a Memorandum Order denying all motions for summary judgment and establishing certain legal standards to govern at trial. In December 2009, a new trial judge was assigned to the case, who then entered an order granting a motion to reconsider the rulings in the November 2008 Memorandum Order. In April 2010, the new judge issued an opinion, again denying all motions for summary judgment and establishing certain legal standards to govern at trial. The non-jury trial on liability only was held in September 2010. Plaintiffs filed their proposed findings of fact and conclusions of law in December 2010, Allegheny made its related filings in February 2011 and plaintiffs filed their responses in April 2011. The parties are awaiting a decision from the District Court, but there is no deadline for that decision.

In September 2007, Allegheny also received a NOV from the EPA alleging NSR and PSD violations under the CAA, as well as Pennsylvania and West Virginia state laws at the Hatfield s Ferry and Armstrong generation facilities in Pennsylvania and the Fort Martin and Willow Island generation facilities in West Virginia.

FirstEnergy intends to vigorously defend against the CAA matters described above but cannot predict their outcomes.

State Air Quality Compliance

In early 2006, Maryland passed the Healthy Air Act, which imposes state-wide emission caps on SO_2 and NO_X, requires mercury emission reductions and mandates that Maryland join the RGGI and participate in that coalition s regional efforts to reduce CO_2 emissions. On April 20, 2007, Maryland became the 10th state to join the RGGI. The Healthy Air Act provides a conditional exemption for the R. Paul Smith power station for NO_X, SO_2 and mercury, based on a PJM declaration that the station is vital to reliability in the Baltimore/Washington DC metropolitan area, which PJM determined in 2006. Pursuant to the legislation, the Maryland Department of the Environment (MDE) passed alternate NO_X and SO_2 limits for R. Paul Smith, which became effective in April 2009. However, R. Paul Smith is still required to meet the Healthy Air Act mercury reductions of 80% beginning in 2010. The statutory exemption does not extend to R. Paul Smith s CO_2 emissions. Maryland issued final regulations to implement RGGI requirements in February 2008. Ten RGGI auctions have been held through the end of calendar year 2010. RGGI allowances are also readily available in the allowance markets, affording another mechanism by which to secure necessary allowances. On March 14, 2011, MDE requested PJM perform an analysis to determine if termination of operation at R. Paul Smith would adversely impact the reliability of electrical service in the PJM region under current system conditions. FirstEnergy is unable to predict the outcome of this matter.

In January 2010, the WVDEP issued a NOV for opacity emissions at Allegheny s Pleasants generating facility. FirstEnergy is discussing with WVDEP steps to resolve the NOV including installing a reagent injection system to reduce opacity.

National Ambient Air Quality Standards

The EPA s CAIR requires reductions of NOx and SO_2 emissions in two phases (2009/2010 and 2015), ultimately capping SO_2 emissions in affected states to 2.5 million tons annually and NOx emissions to 1.3 million tons annually. In 2008, the U.S. Court of Appeals for the District of Columbia Circuit vacated CAIR in its entirety and directed the EPA to redo its analysis from the ground up. In December 2008, the Court reconsidered its prior ruling and allowed CAIR to remain in effect to temporarily preserve its environmental values until the EPA replaces CAIR with a new rule consistent with the Court s opinion. The Court ruled in a different case that a cap-and-trade program similar to CAIR, called the NOx SIP Call, cannot be used to satisfy certain CAA requirements (known as reasonably available control technology) for areas in non-attainment under the 8-hour ozone NAAQS. In July 2010, the EPA proposed the Clean Air Transport Rule (CATR) to replace CAIR, which remains in effect until the EPA finalizes CATR. CATR requires reductions of NOx and SO_2 emissions in two phases (2012 and 2014), ultimately capping SO_2 emissions in affected states to 2.6 million tons annually and NOx emissions to 1.3 million tons annually. The EPA proposed a preferred regulatory approach that allows trading of NOx and SO_2 emission allowances between power plants located in the same state and severely limits interstate trading of NOx and SO_2 emission allowances. The EPA also requested comment on two alternative approaches the first eliminates interstate trading of NOx and SO_2 emission allowances and the second eliminates trading of NOx and SO_2 emission allowances in its entirety. Depending on the actions taken by the EPA with respect to CATR, the proposed MACT regulations discussed below and any future regulations that are ultimately implemented, FGCO s future cost of compliance may be substantial. Management is currently assessing the impact of these environmental proposals and other factors on FGCO s facilities, particularly on the operation of its smaller, non-supercritical units. For example, as disclosed herein, management decided to idle certain units or operate them on a seasonal basis until developments clarify.

Hazardous Air Pollutant Emissions

On March 16, 2011, the EPA released its MACT proposal to establish emission standards for mercury, hydrochloric acid and various metals for electric generating units. Depending on the action taken by the EPA and how any future regulations are ultimately implemented, FirstEnergy s future cost of compliance with MACT regulations may be substantial and changes to FirstEnergy s operations may result.

Climate Change

There are a number of initiatives to reduce GHG emissions under consideration at the federal, state and international level. At the federal level, members of Congress have introduced several bills seeking to reduce emissions of GHG in the United States, and the House of Representatives passed one such bill, the American Clean Energy and Security Act of 2009, in June 2009. The Senate continues to consider a number of measures to regulate GHG emissions. President Obama has announced his Administration s New Energy for America Plan that includes, among other provisions, proposals to ensure that 10% of electricity used in the United States comes from renewable sources by 2012, to increase to 25% by 2025, to implement an economy-wide cap-and-trade program to reduce GHG emissions by 80% by 2050. Certain states, primarily the northeastern states participating in the RGGI and western states, led by California, have coordinated efforts to develop regional strategies to control emissions of certain GHGs.

In September 2009, the EPA finalized a national GHG emissions collection and reporting rule that required FirstEnergy to measure GHG emissions commencing in 2010 and will require it to submit reports commencing in 2011. In December 2009, the EPA released its final Endangerment and Cause or Contribute Findings for Greenhouse Gases under the Clean Air Act. The EPA s finding concludes that concentrations of several key GHGs increase the threat of climate change and may be regulated as air pollutants under the CAA. In April 2010, the EPA finalized new GHG standards for model years 2012 to 2016 passenger cars, light-duty trucks and medium-duty passenger vehicles and clarified that GHG regulation under the CAA would not be triggered for electric generating plants and other stationary sources until January 2, 2011, at the earliest. In May 2010, the EPA finalized new thresholds for GHG emissions that define when permits under the CAA s NSR program would be required. The EPA established an emissions applicability threshold of 75,000 tons per year (tpy) of carbon dioxide equivalents (CO2e) effective January 2, 2011 for existing facilities under the CAA s PSD program. Until July 1, 2011, this emissions applicability threshold will only apply if PSD is triggered by non-CO_2 pollutants.

At the international level, the Kyoto Protocol, signed by the U.S. in 1998 but never submitted for ratification by the U.S. Senate, was intended to address global warming by reducing the amount of man-made GHG, including CO_2, emitted by developed countries by 2012. A December 2009 U.N. Climate Change Conference in Copenhagen did not reach a consensus on a successor treaty to the Kyoto Protocol, but did take note of the Copenhagen Accord, a non-binding political agreement that recognized the scientific view that the increase in global temperature should be below two degrees Celsius; includes a commitment by developed countries to provide funds, approaching $30 billion over the next three years with a goal of increasing to $100 billion by 2020; and establishes the Copenhagen Green Climate Fund to support mitigation, adaptation, and other climate-related activities in developing countries. To the extent that they have become a party to the Copenhagen Accord, developed economies, such as the European Union, Japan, Russia and the United States, would commit to quantified economy-wide emissions targets from 2020, while developing countries, including Brazil, China and India, would agree to take mitigation actions, subject to their domestic measurement, reporting and verification.

In 2009, the U.S. Court of Appeals for the Second Circuit and the U.S. Court of Appeals for the Fifth Circuit reversed and remanded lower court decisions that had dismissed complaints alleging damage from GHG emissions on jurisdictional grounds. However, a subsequent ruling from the U.S. Court of Appeals for the Fifth Circuit reinstated the lower court dismissal of a complaint alleging damage from GHG emissions. These cases involve common law tort claims, including public and private nuisance, alleging that GHG emissions contribute to global warming and result in property damages. The U.S. Supreme Court granted a writ of certiorari to review the decision of the Second Circuit. Oral argument was held on April 19, 2011, and a decision is expected by July 2011. While FirstEnergy is not a party to this litigation, FirstEnergy and/or one or more of its subsidiaries could be named in actions making similar allegations.

FirstEnergy cannot currently estimate the financial impact of climate change policies, although potential legislative or regulatory programs restricting CO_2 emissions, or litigation alleging damages from GHG emissions, could require significant capital and other expenditures or result in changes to its operations. The CO_2 emissions per KWH of electricity generated by FirstEnergy is lower than many of its regional competitors due to its diversified generation sources, which include low or non-CO_2 emitting gas-fired and nuclear generators.

Clean Water Act

Various water quality regulations, the majority of which are the result of the federal Clean Water Act and its amendments, apply to FirstEnergy s plants. In addition, the states in which FirstEnergy operates have water quality standards applicable to FirstEnergy s operations.

The EPA established new performance standards under Section 316(b) of the Clean Water Act for reducing impacts on fish and shellfish from cooling water intake structures at certain existing electric generating plants. The regulations call for reductions in impingement mortality (when aquatic organisms are pinned against screens or other parts of a cooling water intake system) and entrainment (which occurs when aquatic life is drawn into a facility s cooling water system). The EPA has taken the position that until further rulemaking occurs, permitting authorities should continue the existing practice of applying their best professional judgment to minimize impacts on fish and shellfish from cooling water intake structures. In April 2009, the U.S. Supreme Court reversed one significant aspect of the Second Circuit s opinion and decided that Section 316(b) of the Clean Water Act authorizes the EPA to compare costs with benefits in determining the best technology available for minimizing adverse environmental impact at cooling water intake structures. On March 28, 2011, the EPA released a new proposed regulation under Section 316(b) of the Clean Water Act generally requiring fish impingement to be reduced to a 12% annual average and studies to be conducted at the majority of our existing generating facilities to assist permitting authorities to determine whether and what site-specific controls, if any, would be required to reduce entrainment of aquatic life. FirstEnergy is studying various control options and their costs and effectiveness, including pilot testing of reverse louvers in a portion of the Bay Shore power plant s water intake channel to divert fish away from the plant s water intake system. In November 2010, the Ohio EPA issued a permit for the Bay Shore power plant requiring installation of reverse louvers in its entire water intake channel by December 31, 2014. Depending on the results of such studies and the EPA s further rulemaking and any final action taken by the states exercising best professional judgment, the future costs of compliance with these standards may require material capital expenditures.

In April 2011, the U.S. Attorney s Office in Cleveland, Ohio advised FGCO that it is no longer considering prosecution under the Clean Water Act and the Migratory Bird Treaty Act for three petroleum spills at the Edgewater, Lakeshore and Bay Shore plants which occurred on November 1, 2005, January 26, 2007 and February 27, 2007. This matter has been referred back to EPA for civil enforcement and FGCO is unable to predict the outcome of this matter.

Monongahela River Water Quality

In late 2008, the PA DEP imposed water quality criteria for certain effluents, including TDS and sulfate concentrations in the Monongahela River, on new and modified sources, including the scrubber project at the Hatfield s Ferry generation facility. These criteria are reflected in the current PA DEP water discharge permit for that project. AE Supply appealed the PA DEP s permitting decision, which would require it to incur significant costs or negatively affect its ability to operate the scrubbers as designed. Preliminary studies indicate an initial capital investment in excess of $150 million in order to install technology to meet the TDS and sulfate limits in the permit. The permit has been independently appealed by Environmental Integrity Project and Citizens Coal Council, which seeks to impose more stringent technology-based effluent limitations. Those same parties have intervened in the appeal filed by AE Supply, and both appeals have been consolidated for discovery purposes. An order has been entered that stays the permit limits that AE Supply has challenged while the appeal is pending. The hearing is scheduled to begin on September 13, 2011. AE Supply intends to vigorously pursue these issues, but cannot predict the outcome of these appeals.

In a parallel rulemaking, the PA DEP recommended, and in August 2010, the Pennsylvania Environmental Quality Board issued, a final rule imposing end-of-pipe TDS effluent limitations. FirstEnergy could incur significant costs for additional control equipment to meet the requirements of this rule, although its provisions do not apply to electric generating units until the end of 2018, and then only if the EPA has not promulgated TDS effluent limitation guidelines applicable to such units.

In December 2010, PA DEP submitted its Clean Water Act 303(d) list to the EPA with a recommended sulfate impairment designation for an approximately 68 mile stretch of the Monongahela River north of the West Virginia border. EPA has not acted on PA DEP s recommendation. If the designation is approved, Pennsylvania will then need to develop a TMDL limit for the river, a process that will take about five years. Based on the stringency of the TMDL, FirstEnergy may incur significant costs to reduce sulfate discharges into the Monongahela River from its Hatfield s Ferry and Mitchell facilities in Pennsylvania and its Fort Martin facility in West Virginia.

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In October 2009, the WVDEP issued the water discharge permit for the Fort Martin generation facility. Similar to the Hatfield s Ferry water discharge permit issued for the scrubber project, the Fort Martin permit imposes effluent limitations for TDS and sulfate concentrations. The permit also imposes temperature limitations and other effluent limits for heavy metals that are not contained in the Hatfield s Ferry water permit. Concurrent with the issuance of the Fort Martin permit, WVDEP also issued an administrative order that sets deadlines for MP to meet certain of the effluent limits that are effective immediately under the terms of the permit. MP appealed the Fort Martin permit and the administrative order. The appeal included a request to stay certain of the conditions of the permit and order while the appeal is pending, which was granted pending a final decision on appeal and subject to WVDEP moving to dissolve the stay. The appeals have been consolidated. MP moved to dismiss certain of the permit conditions for the failure of the WVDEP to submit those conditions for public review and comment during the permitting process. An agreed-upon order that suspends further action on this appeal, pending WVDEP s release for public review and comment on those conditions, was entered on August 11, 2010. The stay remains in effect during that process. The current terms of the Fort Martin permit would require MP to incur significant costs or negatively affect operations at Fort Martin. Preliminary information indicates an initial capital investment in excess of the capital investment that may be needed at Hatfield s Ferry in order to install technology to meet the TDS and sulfate limits in the Fort Martin permit, which technology may also meet certain of the other effluent limits in the permit. Additional technology may be needed to meet certain other limits in the permit. MP intends to vigorously pursue these issues but cannot predict the outcome of these appeals.

Regulation of Waste Disposal

Federal and state hazardous waste regulations have been promulgated as a result of the Resource Conservation and Recovery Act of 1976, as amended, and the Toxic Substances Control Act of 1976. Certain fossil-fuel combustion residuals, such as coal ash, were exempted from hazardous waste disposal requirements pending the EPA s evaluation of the need for future regulation. In February 2009, the EPA requested comments from the states on options for regulating coal combustion residuals, including whether they should be regulated as hazardous or non-hazardous waste.

In December 2009, in an advanced notice of public rulemaking, the EPA asserted that the large volumes of coal combustion residuals produced by electric utilities pose significant financial risk to the industry. In May 2010, the EPA proposed two options for additional regulation of coal combustion residuals, including the option of regulation as a special waste under the EPA s hazardous waste management program which could have a significant impact on the management, beneficial use and disposal of coal combustion residuals. FirstEnergy s future cost of compliance with any coal combustion residuals regulations that may be promulgated could be substantial and would depend, in part, on the regulatory action taken by the EPA and implementation by the EPA or the states.

The Utility Registrants have been named as potentially responsible parties 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 potentially responsible parties for a particular site may be liable on a joint and several basis. Environmental liabilities that are considered probable have been recognized on the consolidated balance sheet as of March 31, 2011, based on estimates of the total costs of cleanup, the Utility Registrants proportionate responsibility for such costs and the financial ability of other unaffiliated entities to pay. Total liabilities of approximately $104 million (JCP&L $69 million, TE $1 million, CEI $1 million, FGCO $1 million and FirstEnergy $32 million) have been accrued through March 31, 2011. Included in the total are accrued liabilities of approximately $64 million for environmental remediation of former manufactured gas plants and gas holder facilities in New Jersey, which are being recovered by JCP&L through a non-bypassable SBC.

Other Legal Proceedings

Power Outages and Related Litigation

In July 1999, the Mid-Atlantic States experienced a severe heat wave, which resulted in power outages throughout the service territories of many electric utilities, including JCP&L. Two class action lawsuits (subsequently consolidated into a single proceeding) were filed in New Jersey Superior Court in July 1999 against JCP&L, GPU and other GPU companies, seeking compensatory and punitive damages due to the outages. After various motions, rulings and appeals, the Plaintiffs claims for consumer fraud, common law fraud, negligent misrepresentation, strict product liability and punitive damages were dismissed, leaving only the negligence and breach of contract causes of actions. On July 29, 2010, the Appellate Division upheld the trial court s decision decertifying the class. Plaintiffs have filed, and JCP&L has opposed, a motion for leave to appeal to the New Jersey Supreme Court. In November 2010, the Supreme Court issued an order denying Plaintiffs motion. The Court s order effectively ends the class action attempt, and leaves only nine (9) plaintiffs to pursue their respective individual claims. The remaining individual plaintiffs have not taken any affirmative steps to pursue their individual claims.

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Nuclear Plant Matters

Under NRC regulations, FirstEnergy must ensure that adequate funds will be available to decommission its nuclear facilities. As of March 31, 2011, FirstEnergy had approximately $2 billion invested in external trusts to be used for the decommissioning and environmental remediation of Davis-Besse, Beaver Valley, Perry and TMI-2. FirstEnergy provides an additional $15 million parental guarantee associated with the funding of decommissioning costs for these units. As required by the NRC, FirstEnergy annually recalculates and adjusts the amount of its parental guarantee, as appropriate. The values of FirstEnergy s nuclear decommissioning trusts fluctuate based on market conditions. If the value of the trusts decline by a material amount, FirstEnergy s obligation to fund the trusts may increase. Disruptions in the capital markets and their effects on particular businesses and the economy could also affect the values of the nuclear decommissioning trusts. The NRC issued guidance anticipating an increase in low-level radioactive waste disposal costs associated with the decommissioning of FirstEnergy s nuclear facilities. On March 28, 2011, FENOC submitted its biennial report on nuclear decommissioning funding to the NRC. This submittal identified a total shortfall in nuclear decommissioning funding for Beaver Valley Unit 1 and Perry of approximately $92.5 million. This estimate encompasses the shortfall covered by the existing $15 million parental guarantee. FENOC agreed to increase the parental guarantee to $95 million within 90 days of the submittal.

In August 2010, FENOC submitted an application to the NRC for renewal of the Davis-Besse Nuclear Power Station operating license for an additional twenty years, until 2037. By an order dated April 26, 2011, the NRC Atomic Safety and Licensing Board (ASLB) granted a hearing on the Davis-Besse license renewal application to a group of petitioners. By this order, the ASLB also admitted two contentions regarding (1) a combination of renewable alternatives to the renewal of Davis-Besse s operating license, and (2) the cost of mitigating a severe accident at Davis-Besse. FENOC is currently evaluating these developments and considering an appropriate response. On April 14, 2011, a group of environmental organizations petitioned the NRC Commissioners to suspend all pending nuclear license renewal proceedings, including the Davis-Besse proceeding, to ensure that any safety and environmental implications of the Fukushima Daiichi Nuclear Power Station event in Japan are considered.

In January 2004, subsidiaries of FirstEnergy filed a lawsuit in the U.S. Court of Federal Claims seeking damages in connection with costs incurred at the Beaver Valley, Davis-Besse and Perry Nuclear facilities as a result of the DOE failure to begin accepting spent nuclear fuel on January 31, 1998. DOE was required to so commence accepting spent nuclear fuel by the Nuclear Waste Policy Act (42 USC 10101 et seq) and the contracts entered into by the DOE and the owners and operators of these facilities pursuant to the Act. On January 18, 2011, the parties, FirstEnergy and DOJ, filed a joint status report that established a schedule for the litigation of these claims. FirstEnergy filed damages schedules and disclosures with the DOJ on February 11, 2011, seeking approximately $57 million in damages for delay costs incurred through September 30, 2010. The damage claim is subject to review and audit by DOE.

Other Legal Matters

In February 2010, a class action lawsuit was filed in Geauga County Court of Common Pleas against FirstEnergy, CEI and OE seeking declaratory judgment and injunctive relief, as well as compensatory, incidental and consequential damages, on behalf of a class of customers related to the reduction of a discount that had previously been in place for residential customers with electric heating, electric water heating, or load management systems. The reduction in the discount was approved by the PUCO. In March 2010, the named-defendant companies filed a motion to dismiss the case due to the lack of jurisdiction of the court of common pleas. The court granted the motion to dismiss on September 7, 2010. The plaintiffs appealed the decision to the Court of Appeals of Ohio, which has not yet rendered an opinion.

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

FirstEnergy accrues legal liabilities only when it concludes that it is probable that it has an obligation for such costs and can reasonably estimate the amount of such costs. If it were ultimately determined that FirstEnergy or its subsidiaries have legal liability or are otherwise made subject to liability based on the above matters, it could have a material adverse effect on FirstEnergy s or its subsidiaries financial condition, results of operations and cash flows.

NEW ACCOUNTING STANDARDS AND INTERPRETATIONS

See Note 12 of the Combined Notes to the Consolidated Financial Statements (Unaudited) for discussion of new accounting pronouncements.

FIRSTENERGY SOLUTIONS CORP.
MANAGEMENT S NARRATIVE
ANALYSIS OF RESULTS OF OPERATIONS

FES is a wholly owned subsidiary of FirstEnergy. FES provides energy-related products and services, and through its subsidiaries, FGCO and NGC, owns or leases, operates and maintains FirstEnergy s fossil and hydroelectric generation facilities (excluding the Allegheny facilities), and owns FirstEnergy s nuclear generation facilities, respectively. FENOC, a wholly owned subsidiary of FirstEnergy, operates and maintains the nuclear generating facilities.

FES revenues are derived from sales to individual retail customers, sales to communities in the form of government aggregation programs, and its participation in affiliated and non-affiliated POLR auctions. FES sales are primarily concentrated in Ohio, Pennsylvania, Illinois, Maryland, Michigan and New Jersey. In 2010, FES also supplied the POLR default service requirements of Met-Ed and Penelec.

The demand for electricity produced and sold by FES, along with the price of that electricity, is impacted by conditions in competitive power markets, global economic activity, economic activity in the Midwest and Mid-Atlantic regions and weather conditions.

For additional information with respect to FES, please see the information contained in FirstEnergy s Management s Discussion and Analysis of Financial Condition and Results of Operations under the following subheadings, which information is incorporated by reference herein: Capital Resources and Liquidity, Guarantees and Other Assurances, Off-Balance Sheet Arrangements, Market Risk Information, Credit Risk, Outlook and New Accounting Standards and Interpretations.

Results of Operations

Earnings available to parent decreased by $44 million in the first three months of 2011 compared to the same period of 2010. The decrease was primarily due to increased transmission expenses, an inventory valuation adjustment, non-core asset impairments and mark-to-market accounting.

Revenues

Total revenues increased $3 million in the first three months of 2011, compared to the same period of 2010, primarily due to growth in direct and government aggregation sales, partially offset by decreases in POLR sales.

The increase in revenues resulted from the following sources:

Revenues by Type of Service	Three Months Ended March 31 2011	2010	Increase (Decrease)
	(In millions)		
Direct and Government Aggregation	$ 840	$ 512	$ 328
POLR	369	673	(304)
Other Wholesale	96	91	5
Transmission	26	17	9
RECs	32	67	(35)
Other	28	28	
Total Revenues	**$ 1,391**	**$ 1,388**	**$ 3**

MWH Sales by Type of Service	Three Months Ended March 31 2011	2010	Increase (Decrease)
	(In thousands)		
Direct	9,671	5,854	65.2%
Government Aggregation	4,310	2,732	57.8%
POLR	5,714	13,276	(57.0)%

Wholesale	1,113	898	23.9%
Total Sales	**20,808**	**22,760**	**(8.6)%**

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The increase in direct and government aggregation revenues of $328 million resulted from the acquisition of new commercial and industrial customers and new government aggregation contracts with communities in Ohio, in addition, sales to residential and small commercial customers were bolstered by weather in the delivery area that was 5.2% colder than in 2010.

The decrease in POLR revenues of $304 million was due to lower sales volumes to the Pennsylvania and Ohio Companies, partially offset by increased sales to non-associated companies and higher unit prices to the Pennsylvania Companies. Participation in POLR auctions and RFPs are expected to continue, but the concentration of these sales will primarily be dependent on our success in our direct retail and aggregation sales channels.

Wholesale revenues increased $5 million due to increased volumes partially offset by lower wholesale prices. The higher sales volumes were the result of increased short term (net hourly position) transactions in MISO. $22 million of wholesale revenue resulted from long positions in MISO that were unable to be netted with short positions in PJM, due to separate settlement requirements within each RTO.

The following tables summarize the price and volume factors contributing to changes in revenues from generation sales:

Source of Change in Direct and Government Aggregation	**Increase (Decrease)** *(In millions)*
Direct Sales:	
Effect of increase in sales volumes	$ 223
Change in prices	(4)
	219
Government Aggregation:	
Effect of increase in sales volumes	100
Change in prices	9
	109
Net Increase in Direct and Government Aggregation Revenues	$ 328

Source of Change in POLR Revenues	**Increase (Decrease)** *(In millions)*
POLR:	
Effect of decrease in sales volumes	$ (384)
Change in prices	80
	(304)

Source of Change in Wholesale Revenues	**Increase (Decrease)** *(In millions)*
Wholesale:	
Effect of increase in sales volumes	12
Change in prices	(7)

5

Transmission revenues increased $9 million due primarily to higher MISO congestion revenues. The revenues derived from the sale of RECs declined $35 million in the first quarter of 2011.

Expenses

Total operating expenses increased $81 million in the first three months of 2011, compared with the same period of 2010.

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The following table summarizes the factors contributing to the changes in fuel and purchased power costs in the first three months of 2011, compared with the same period last year:

Source of Change in Fuel and Purchased Power	**Increase (Decrease)** *(In millions)*
Fossil Fuel:	
Change due to decreased unit costs	$ (22)
Change due to volume consumed	31
	9
Nuclear Fuel:	
Change due to increased unit costs	6
Change due to volume consumed	
	6
Non-affiliated Purchased Power:	
Change due to increased unit costs	32
Change due to volume purchased	(185)
	(153)
Affiliated Purchased Power:	
Change due to increased unit costs	20
Change due to volume purchased	(12)
	8
Net Decrease in Fuel and Purchased Power Costs	**$ (130)**

Fossil fuel costs increased $9 million in the first three months of 2011, compared to the same period of 2010, as a result of higher generation at the fossil units, partially offset by decreased fossil unit costs. Fossil unit prices declined primarily due to improved generating unit availability at more efficient units, partially offset by increased coal transportation costs. Nuclear fuel expenses increased primarily due to higher unit prices following the refueling outages that occurred in 2010.

Non-affiliated purchased power costs decreased $153 million due primarily to lower volumes purchased, partially offset by higher unit costs. The decrease in volume relates to the absence in 2011 of a 1,300 MW third party contract associated with serving Met-Ed and Penelec. $35 million of purchased power expense resulted from long positions in MISO that were unable to be netted with short positions in PJM, due to separate settlement requirements within each RTO.

Other operating expenses increased $191 million in the first three months of 2011, compared to the same period of 2010, as a result of increased RTO transmission costs ($111 million), an inventory valuation adjustment ($54 million) and increased nuclear operating costs ($15 million) related to higher labor and related benefits, partially offset by lower professional and contractor costs.

In the first three month of 2011, impairment charges of long-lived assets increased expenses by $14 million.

General taxes increased $2 million due to an increase in revenue-related taxes.

Other Expense

Total other expense decreased $9 million in the first three months of 2011, compared to the same period of 2010, primarily due to an increase in miscellaneous income ($16 million) and increased investment income ($5 million), partially offset by an increase in interest expense (net of capitalized interest $12 million). Increased miscellaneous income was the result of mark-to-market adjustments on power related derivatives. Increased investment income was the result of higher nuclear decommissioning trust investment income. The increase in interest expense was the result of reduced capitalized interest associated with the completion of the Sammis AQC project in 2010 combined with increased interest expense associated with the restructuring of certain variable rate PCRBs into fixed rate modes.

OHIO EDISON COMPANY
MANAGEMENT S NARRATIVE
ANALYSIS OF RESULTS OF OPERATIONS

OE is a wholly owned electric utility subsidiary of FirstEnergy. OE and its wholly owned subsidiary, Penn, conduct business in portions of Ohio and Pennsylvania, providing regulated electric distribution services. They procure generation services for those franchise customers electing to retain OE and Penn as their power supplier.

For additional information with respect to OE, please see the information contained in FirstEnergy s Management s Discussion and Analysis of Financial Condition and Results of Operations under the following subheadings, which information is incorporated by reference herein: Capital Resources and Liquidity, Guarantees and Other Assurances, Off-Balance Sheet Arrangements, Market Risk Information, Credit Risk, Outlook and New Accounting Standards and Interpretations.

Results of Operations

Earnings available to parent decreased by $6 million in the first three months of 2011, compared to the same period of 2010. The decrease primarily resulted from lower revenues and higher other operating costs, partially offset by lower purchased power costs and amortization of regulatory assets.

Revenues

Revenues decreased $116 million, or 23%, in the first three months of 2011, compared with the same period in 2010, due primarily to a decrease in generation revenues, partially offset by higher distribution revenues.

Distribution revenues increased $10 million in the first three months of 2011, compared to the same period in 2010, primarily due to an increase in KWH deliveries and higher average prices in all customer classes. The higher KWH deliveries in the residential class were influenced by increased weather-related usage in the first three months of 2011, reflecting a 5% increase in heating degree days in OE s service territory.

Changes in distribution KWH deliveries and revenues in the first three months of 2011, compared to the same period in 2010, are summarized in the following tables:

Distribution KWH Deliveries	**Increase**
Residential	1.4%
Commercial	1.2%
Industrial	9.3%
Increase in Distribution Deliveries	**3.7%**

Distribution Revenues	**Increase** *(In millions)*
Residential	$ 7
Commercial	1
Industrial	2
Increase in Distribution Revenues	**$ 10**

Retail generation revenues decreased $127 million primarily due to a decrease in KWH sales and lower average prices in all customer classes. Retail generation obligations are attributable to non-shopping customers and are procured through full-requirements auctions. OE defers the difference between retail generation revenues and costs, resulting in no material effect to current period earnings. Lower KWH sales were primarily the result of increased customer shopping, partially offset by increased weather-related usage in the first three months of 2011, as described above.

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Changes in retail generation KWH sales and revenues in the first three months of 2011, compared to the same period in 2010, are summarized in the following tables:

Retail Generation KWH Sales	Decrease
Residential	(33.0)%
Commercial	(43.2)%
Industrial	(16.3)%
Decrease in Retail Generation Sales	**(32.0)%**

Retail Generation Revenues	Decrease (In millions)
Residential	$ (85)
Commercial	(30)
Industrial	(12)
Decrease in Retail Generation Revenues	**$ (127)**

Expenses

Total expenses decreased $108 million in the first three months of 2011, compared to the same period of 2010. The following table presents changes from the prior period by expense category:

Expenses Changes	Increase (Decrease) (In millions)
Purchased power costs	$ (94)
Other operating expenses	13
Amortization of regulatory assets, net	(29)
General taxes	2
Net Decrease in Expenses	**$ (108)**

Purchased power costs decreased in the first three months of 2011, compared to the same period of 2010, primarily due to lower KWH purchases resulting from reduced generation sales requirements in the first three months of 2011 coupled with lower unit costs. The increase in other operating costs for the first three months of 2011 was primarily due to expenses associated with the 2011 Beaver Valley Unit 2 refueling outage that were absent in 2010. The amortization of regulatory assets decreased primarily due to higher deferred residential generation credits in 2011.

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THE CLEVELAND ELECTRIC ILLUMINATING COMPANY
MANAGEMENT S NARRATIVE
ANALYSIS OF RESULTS OF OPERATIONS

CEI is a wholly owned electric utility subsidiary of FirstEnergy. CEI conducts business in northeastern Ohio, providing regulated electric distribution services. CEI also procures generation services for those customers electing to retain CEI as their power supplier.

For additional information with respect to CEI, please see the information contained in FirstEnergy s Management s Discussion and Analysis of Financial Condition and Results of Operations under the following subheadings, which information is incorporated by reference herein: Capital Resources and Liquidity, Guarantees and Other Assurances, Off-Balance Sheet Arrangements, Market Risk Information, Credit Risk, Outlook and New Accounting Standards and Interpretations.

Results of Operations

Earnings available to parent decreased by $1 million in the first three months of 2011, compared to the same period of 2010. The decrease in earnings was primarily due to lower revenues, partially offset by lower purchased power and amortization of regulatory assets.

Revenues

Revenues decreased $105 million, or 32%, in the first three months of 2011, compared to the same period of 2010, due to lower retail generation and distribution revenues.

Distribution revenues decreased $5 million in the first three months of 2011, compared to the same period of 2010, due to lower average unit prices for the industrial and residential customer classes offset by increased KWH deliveries across all sectors. The lower average unit prices were the result of the absence of transition charges in 2011. Higher KWH deliveries in the residential class were influenced by increased weather-related usage in the first three months of 2011, reflecting a 10% increase in heating degree days in CEI s service territory.

Changes in distribution KWH deliveries and revenues in the first three months of 2011, compared to the same period of 2010, are summarized in the following tables:

Distribution KWH Deliveries	**Increase**
Residential	2.3%
Commercial	3.1%
Industrial	0.9%
Increase in Distribution Deliveries	**2.1%**

Distribution Revenues	**Increase (Decrease)** ***(In millions)***
Residential	$
Commercial	7
Industrial	(12)
Net Decrease in Distribution Revenues	**$ (5)**

Retail generation revenues decreased $101 million in the first three months of 2011, compared to the same period of 2010, primarily due to lower KWH sales and lower average unit prices across all customer classes. Retail generation obligations are attributable to non-shopping customers and are procured through full-requirements auctions. CEI defers the difference between retail generation revenues and costs, resulting in no material effect to current period earnings. Reduced KWH sales were primarily the result of increased customer shopping in the first three months of 2011, partially offset by higher residential KWH deliveries resulting from the colder weather conditions. Lower average unit prices in the residential customer class were the result of generation credits in place for 2011.
Changes in retail generation sales and revenues in the first three months of 2011, compared to the same period of 2010, are summarized in the following tables:

Retail Generation KWH Sales	Decrease
Residential	(48.4)%
Commercial	(48.3)%
Industrial	(62.8)%
Decrease in Retail Generation Sales	**(53.3)%**

Retail Generation Revenues	Decrease
	(In millions)
Residential	$ (46)
Commercial	(29)
Industrial	(26)
Decrease in Retail Generation Revenues	**$ (101)**

Expenses
Total expenses decreased $98 million in the first three months of 2011, compared to the same period of 2010. The following table presents the change from the prior period by expense category:

Expenses Changes	Increase (Decrease)
	(In millions)
Purchased power costs	$ (82)
Other operating costs	4
Amortization of regulatory assets, net	(22)
General taxes	2
Net Decrease in Expenses	**$ (98)**

Purchased power costs decreased in the first three months of 2011 due to lower KWH purchases resulting from reduced sales requirements in the first three months of 2011. Other operating expenses increased due to 2011 inventory valuation adjustments. Decreased amortization of regulatory assets was primarily due to completion of transition cost recovery at the end of 2010 and 2011 and deferred residential generation credits, partially offset by increased recovery of non-residential distribution deferrals and the absence in 2010 of deferred renewable energy credit expenses. General taxes increased in the first three months of 2011 due to increased property taxes in 2011.

THE TOLEDO EDISON COMPANY
MANAGEMENT S NARRATIVE
ANALYSIS OF RESULTS OF OPERATIONS

TE is a wholly owned electric utility subsidiary of FirstEnergy. TE conducts business in northwestern Ohio, providing regulated electric distribution services. TE also procures generation services for those customers electing to retain TE as their power supplier.

For additional information with respect to TE, please see the information contained in FirstEnergy s Management s Discussion and Analysis of Financial Condition and Results of Operations under the following subheadings, which information is incorporated by reference herein: Capital Resources and Liquidity, Guarantees and Other Assurances, Off-Balance Sheet Arrangements, Market Risk Information, Credit Risk, Outlook and New Accounting Standards and Interpretations.

Results of Operations

Earnings available to parent decreased by $2 million in the first three months of 2011, compared to the same period of 2010. The decrease primarily resulted from lower revenues and higher other operating costs, partially offset by lower purchased power costs and deferral of regulatory assets.

Revenues

Revenues decreased $19 million, or 14%, in the first three months of 2011, compared to the same period of 2010, due to a decrease in retail generation revenues, partially offset by higher distribution revenues and wholesale generation revenues.

Distribution revenues increased $2 million in the first three months of 2011, compared to the same period of 2010, due to higher residential and industrial revenues, partially offset by lower commercial revenues. Residential and industrial revenues were the result of higher average unit prices and higher KWH deliveries. The higher KWH deliveries in the residential class were influenced by increased weather-related usage in the first three months of 2011, reflecting a 9% increase in heating degree days in TE s service territory. Commercial revenues were impacted by lower KWH deliveries and lower average unit prices.

Changes in distribution KWH deliveries and revenues in the first three months of 2011, compared to the same period of 2010, are summarized in the following tables:

Distribution KWH Deliveries	**Increase (Decrease)**
Residential	3.6%
Commercial	(2.3)%
Industrial	5.3%
Net Increase in Distribution Deliveries	**3.3%**

Distribution Revenues	**Increase (Decrease)** *(In millions)*
Residential	$ 2
Commercial	(1)
Industrial	1
Net Increase in Distribution Revenues	**$ 2**

Retail generation revenues decreased $25 million in the first three months of 2011, compared to the same period of 2010, due to lower KWH sales to all customer classes and lower unit prices to residential and industrial customers.

Retail generation obligations are attributable to non-shopping customers and are procured through full-requirements auctions. TE defers the difference between retail generation revenues and costs, resulting in no material effect to current period earnings. Lower KWH sales were the result of increased customer shopping, partially offset by increased weather-related usage in the first three months of 2011, as described above.

Changes in retail generation KWH sales and revenues in the first three months of 2011, compared to the same period of 2010, are summarized in the following tables:

Retail Generation KWH Sales	**Decrease**
Residential	(28.5)%
Commercial	(49.5)%
Industrial	(13.1)%
Decrease in Retail Generation Sales	**(24.0)%**

Retail Generation Revenues	**Decrease**	
	(In millions)	
Residential	$	(10)
Commercial		(6)
Industrial		(9)
Decrease in Retail Generation Revenues	**$**	**(25)**

Wholesale revenues increased $3 million in the first three months of 2011, compared to the same period of 2010, primarily due to higher revenues from sales to NGC from TE s leasehold interest in Beaver Valley Unit 2.

Expenses

Total expenses decreased $15 million in the first three months of 2011, compared to the same period of 2010. The following table presents changes from the prior period by expense category:

Expenses Changes	**Increase (Decrease)**	
	(In millions)	
Purchased power costs	$	(24)
Other operating expenses		11
Deferral of regulatory assets, net		(3)
General Taxes		1
Net Decrease in Expenses	**$**	**(15)**

Purchased power costs decreased in the first three months of 2011, compared to the same period of 2010, due to lower KWH purchases resulting from reduced generation sales requirements in the first three months of 2011 coupled with lower unit costs. The increase in other operating costs for the first three months of 2011 was primarily due to expenses associated with the 2011 Beaver Valley Unit 2 refueling outage that were absent in 2010 and higher storm restoration expenses. The deferral of regulatory assets increased due to higher PUCO-approved cost deferrals in the first three months of 2011, compared to the same period of 2010.

JERSEY CENTRAL POWER & LIGHT COMPANY
MANAGEMENT S NARRATIVE
ANALYSIS OF RESULTS OF OPERATIONS

JCP&L is a wholly owned, electric utility subsidiary of FirstEnergy. JCP&L conducts business in New Jersey, providing regulated electric transmission and distribution services. JCP&L also procures generation services for franchise customers electing to retain JCP&L as their power supplier. JCP&L procures electric supply to serve its BGS customers through a statewide auction process approved by the NJBPU.

For additional information with respect to JCP&L, please see the information contained in FirstEnergy s Management s Discussion and Analysis of Financial Condition and Results of Operations under the following subheadings, which information is incorporated by reference herein: Capital Resources and Liquidity, Market Risk Information, Credit Risk, Outlook, Regulatory Matters, Environmental Matters, Other Legal Proceedings and New Accounting Standards and Interpretations.

Results of Operations

Net income decreased by $10 million in the first three months of 2011, compared to the same period of 2010. The decrease was primarily due to lower revenues and increased net amortization of regulatory assets, partially offset by lower purchased power costs and other operating costs.

Revenues

In the first three months of 2011, revenues decreased $57 million, or 8%, compared to the same period of 2010. The decrease in revenues was primarily due to lower distribution and retail generation revenues, partially offset by an increase in wholesale generation and other revenues.

Distribution revenues decreased $17 million in the first three months of 2011, compared to the same period of 2010, primarily due to a NJBPU-approved rate adjustment which became effective March 1, 2011 for all customer classes, partially offset by higher KWH deliveries in the residential class resulting from a 6% increase in heating degree days.

Changes in distribution KWH deliveries and revenues in the first three months of 2011 compared to the same period of 2010 are summarized in the following tables:

Distribution KWH Deliveries	**Increase (Decrease)**
Residential	1.4%
Commercial	(3.4)%
Industrial	(2.0)%
Net Decrease in Distribution Deliveries	**(1.1)%**

Distribution Revenues	**Decrease**
	(In millions)
Residential	$ (5)
Commercial	(10)
Industrial	(2)
Decrease in Distribution Revenues	**$ (17)**

Retail generation revenues decreased $47 million due to lower retail generation KWH sales in all customer classes. Retail generation obligations are attributable to non-shopping customers and are procured through full-requirements auctions. JCP&L defers the difference between retail generation revenues and costs, resulting in no material effect to current period earnings. These lower sales were primarily due to an increase in customer shopping.

Changes in retail generation KWH sales and revenues in the first three months of 2011, compared to the same period of 2010, are summarized in the following tables:

Retail Generation KWH Sales	Decrease
Residential	(7.5)%
Commercial	(26.4)%
Industrial	(23.1)%
Decrease in Retail Generation Sales	**(13.7)%**

Retail Generation Revenues	Decrease *(In millions)*
Residential	$ (15)
Commercial	(29)
Industrial	(3)
Decrease in Retail Generation Revenues	**$ (47)**

Wholesale generation revenues increased $3 million in the first three months of 2011, compared to the same period of 2010, due primarily to an increase in sales volumes.
Other revenues increased $4 million in the first three months of 2011, compared to the same period of 2010, primarily due to an increase in transition bond revenues as a result of higher KWH deliveries to residential customers.

Expenses

Total expenses decreased $43 million in the first three months of 2011, compared to the same period of 2010. The following table presents changes from the prior period by expense category:

Expenses Changes	Increase (Decrease) *(In millions)*
Purchased power costs	$ (44)
Other operating costs	(9)
Provision for depreciation	(3)
Amortization of regulatory assets, net	12
General taxes	1
Net Decrease in Expenses	**$ (43)**

Purchased power costs decreased in the first three months of 2011 primarily due to lower requirements from reduced sales. Other operating costs decreased in the first three months of 2011 primarily due to lower storm restoration costs, partially offset by inventory valuation adjustments. The amortization of regulatory assets increased primarily due to lower storm cost deferrals and the write-off of nonrecoverable NUG costs, partially offset by lower purchased power deferrals in the first quarter of 2011.

METROPOLITAN EDISON COMPANY
MANAGEMENT S NARRATIVE
ANALYSIS OF RESULTS OF OPERATIONS

Met-Ed is a wholly owned electric utility subsidiary of FirstEnergy. Met-Ed conducts business in eastern Pennsylvania, providing regulated electric transmission and distribution services. Met-Ed also procures generation service for those customers electing to retain Met-Ed as their power supplier. In 2011, Met-Ed procures power under its Default Service Plan (DSP) in which full requirements products (energy, capacity, ancillary services, and applicable transmission services) are procured through descending clock auctions.

As authorized by Met-Ed s Board of Directors, Met-Ed repurchased 118,595 shares of its common stock from its parent, FirstEnergy, for $150 million on January 28, 2011.

For additional information with respect to Met-Ed, please see the information contained in FirstEnergy s Management s Discussion and Analysis of Financial Condition and Results of Operations under the following subheadings, which information is incorporated by reference herein: Market Risk Information, Credit Risk, Outlook, Capital Resources and Liquidity, Regulatory Matters, Environmental Matters, Other Legal Proceedings and New Accounting Standards and Interpretations.

Results of Operations

Net income increased by $10 million in the first three months of 2011, compared to the same period of 2010. The increase was primarily due to decreased purchased power, other operating expenses and amortization of net regulatory assets, partially offset by decreased revenues.

Revenues

Revenue decreased $116 million, or 24%, in the first three months of 2011 compared to the same period of 2010, reflecting lower distribution, wholesale generation and transmission revenues, partially offset by an increase in retail generation revenues.

Distribution revenues decreased $72 million in the first three months of 2011, compared to the same period of 2010, primarily due to lower rates resulting from the DSP that began in 2011 that eliminated the transmission component from the distribution rate. Higher KWH deliveries to industrial customers were due to improving economic conditions in Met-Ed s service territory. Higher residential and commercial KWH deliveries reflect increased weather-related usage due to an 8% increase in heating degree days in the first three months of 2011, compared to the same period in 2010.

Changes in distribution KWH deliveries and revenues in the first three months of 2011, compared to the same period of 2010, are summarized in the following tables:

Distribution KWH Deliveries	**Increase**
Residential	3.4%
Commercial	2.5%
Industrial	5.8%
Increase in Distribution Deliveries	**4.1%**

Distribution Revenues	**Decrease** *(In millions)*
Residential	$ (29)
Commercial	(17)
Industrial	(26)
Decrease in Distribution Revenues	**$ (72)**

Retail generation revenues increased $18 million in the first three months of 2011 compared to the same period of 2010, due to an increase in generation rates from the auctions and now including transmission services in the rates under the DSP effective January 1, 2011. The DSP resulted in higher composite unit prices across all customer classes. Higher KWH sales to residential customers were primarily due to weather-related usage as described above. Increased customer shopping in the commercial and industrial classes of 36% and 81%, respectively, reduced KWH sales to these classes. Retail generation obligations are attributable to non-shopping customers and are procured through full-requirements auctions. Met-Ed defers the difference between retail generation revenues and costs, resulting in no material effect to current period earnings.

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Changes in retail generation KWH sales and revenues in the first three months of 2011, compared to the same period of 2010, are summarized in the following tables:

Retail Generation KWH Sales	Increase (Decrease)
Residential	2.7%
Commercial	(34.1)%
Industrial	(80.0)%
Net Decrease in Retail Generation Sales	**(34.5)%**

Retail Generation Revenues	Increase (Decrease) *(In millions)*
Residential	$ 53
Commercial	3
Industrial	(38)
Net Increase in Retail Generation Revenues	**$ 18**

Wholesale revenues decreased $54 million in the first three months of 2011 compared to the same period of 2010, primarily due to Met-Ed ending certain capacity purchase for resale contracts.

Transmission revenues decreased $8 million in the first three months of 2011 compared to the same period of 2010 primarily due to decreased FTR revenues. Met-Ed defers the difference between transmission revenues and transmission costs incurred, resulting in no material effect to current period earnings.

Expenses

Total expenses decreased $121 million in the first three months of 2011 compared to the same period of 2010. The following table presents changes from the prior year by expense category:

Expenses Changes	Decrease *(In millions)*
Purchased power costs	$ (50)
Other operating costs	(54)
Amortization of regulatory assets, net	(17)
Decrease in Expenses	**$ (121)**

Purchased power costs decreased $50 million in the first three months of 2011 due to a decrease in KWH purchased to source generation sales requirements, partially offset by higher unit costs. Other operating costs decreased $54 million in the first three months of 2011 compared to the same period in 2010 primarily due to lower transmission congestion and transmission loss expenses (see reference to deferral accounting above). The amortization of regulatory assets decreased $17 million in the first three months of 2011 primarily due to the termination of transmission and transition tariff riders at the end of 2010.

Other Expense

In the first three months of 2011, interest income decreased due to reduced CTC stranded asset balances compared to the same period of 2010.

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PENNSYLVANIA ELECTRIC COMPANY
MANAGEMENT S NARRATIVE
ANALYSIS OF RESULTS OF OPERATIONS

Penelec is a wholly owned electric utility subsidiary of FirstEnergy. Penelec conducts business in northern and south central Pennsylvania, providing regulated transmission and distribution services. Penelec also procures generation service for those customers electing to retain Penelec as their power supplier. Beginning in 2011, Penelec procures power under its Default Service Plan (DSP) in which full requirements products (energy, capacity, ancillary services, and applicable transmission services) are procured through descending clock auctions.

For additional information with respect to Penelec, please see the information contained in FirstEnergy s Management s Discussion and Analysis of Financial Condition and Results of Operations under the following subheadings, which information is incorporated by reference herein: Capital Resources and Liquidity, Market Risk Information, Credit Risk, Outlook, Regulatory Matters, Environmental Matters, Other Legal Proceedings and New Accounting Standards and Interpretations.

Results of Operations

Net income increased slightly in the first three months of 2011, compared to the same period of 2010. The increase was primarily due to lower purchased power and other operating costs, partially offset by lower revenues, net amortization of regulatory assets and higher general taxes.

Revenues

Revenue decreased $79 million, or 19.5%, in the first three months of 2011 compared to the same period of 2010. The decrease in revenue was primarily due to lower retail and wholesale generation revenues and lower transmission revenues, partially offset by higher distribution revenues.

Distribution revenues increased by $1 million in the first three months of 2011, compared to the same period of 2010, primarily due to an increase in the retail transition rates and energy efficiency rates for all customer classes, partially offset by decreased KWH sales in the residential and commercial classes.

Changes in distribution KWH deliveries and revenues in the first three months of 2011, compared to the same period of 2010, are summarized in the following tables:

Distribution KWH Deliveries	**Increase (Decrease)**
Residential	(0.2)%
Commercial	(3.0)%
Industrial	10.0%
Net Increase in Distribution Deliveries	**3.1%**

Distribution Revenues	**Increase (Decrease)** ***(In millions)***
Residential	$ 3
Commercial	(5)
Industrial	3
Net Increase in Distribution Revenues	**$ 1**

Retail generation revenues decreased $22 million in the first three months of 2011, compared to the same period of 2010, primarily due to lower KWH sales to all customer classes, partially offset by higher generation rates for all customer classes. Retail generation obligations are attributable to non-shopping customers and are procured through full-requirements auctions. Penelec defers the difference between retail generation revenues and costs, resulting in no material effect to current period earnings. Lower sales to all customer classes were primarily due to an increase in customer shopping following the expiration of generation rate caps at the end of 2010. Higher generation rates reflect the inclusion of transmission services in generation rates under the DSP, effective January 1, 2011.

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Changes in retail generation KWH sales and revenues in the first three months of 2011, compared to the same period of 2010, are summarized in the following tables:

Retail Generation KWH Sales	Decrease
Residential	(0.4)%
Commercial	(38.3)%
Industrial	(78.5)%
Decrease in Retail Generation Sales	**(39.1)%**

Retail Generation Revenues	Increase (Decrease) *(In millions)*
Residential	$ 31
Commercial	(9)
Industrial	(44)
Net Decrease in Retail Generation Revenues	**$ (22)**

Wholesale generation revenues decreased $49 million in the first three months of 2011, compared to the same period of 2010, due to Penelec no longer purchasing non-NUG capacity for resale to the PJM market beginning in 2011. Transmission revenues decreased $8 million in the first three months of 2011, compared to the same period of 2010, primarily due to lower Financial Transmission Rights revenues. Penelec defers the difference between transmission revenues and transmission costs incurred, resulting in no material effect to current period earnings.

Expenses

Total expenses decreased by $75 million in the first three months of 2011, as compared with the same period of 2010. The following table presents changes from the prior year by expense category:

Expenses Changes	Increase (Decrease) *(In millions)*
Purchased power costs	$ (71)
Other operating costs	(31)
Amortization of regulatory assets, net	23
General taxes	4
Net Decrease in Expenses	**$ (75)**

Purchased power costs decreased $71 million in the first three months of 2011, compared to the same period of 2010, primarily due to decreased KWH purchased to source generation sales requirements. Other operating costs decreased $31 million in the first three months of 2011, primarily due to lower transmission congestion and transmission loss expenses (see reference to deferral accounting above). The amortization of net regulatory assets increased $23 million in the first three months of 2011, primarily due to reduced NUG deferrals as a result of a NUG Rider implemented in January 2011. General taxes increased $4 million primarily due to higher Pennsylvania Sales and Use Taxes and the absence of a favorable ruling on a property tax appeal in the first quarter of 2010.

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ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

See Management s Discussion and Analysis of Financial Condition and Results of Operations Market Risk Information in Item 2 above.

ITEM 4. CONTROLS AND PROCEDURES

(a) EVALUATION OF DISCLOSURE CONTROLS AND PROCEDURES FIRSTENERGY

FirstEnergy s management, with the participation of its chief executive officer and chief financial officer, have reviewed and evaluated the effectiveness of the registrant s disclosure controls and procedures, as defined in the Securities Exchange Act of 1934, as amended, Rules 13a-15(e) and 15(d)-15(e), as of the end of the period covered by this report. Based on that evaluation, the chief executive officer and chief financial officer have concluded that the registrant s disclosure controls and procedures were effective as of the end of the period covered by this report.

(b) CHANGES IN INTERNAL CONTROL OVER FINANCIAL REPORTING

During the quarter ended March 31, 2011, other than changes resulting from the Allegheny merger discussed below, there have been no changes in internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, FirstEnergy s internal control over financial reporting.

On February 25, 2011, the merger between FirstEnergy and Allegheny closed. FirstEnergy is currently in the process of integrating Allegheny s operations, processes, and internal controls. See Note 2 to the consolidated financial statements in Part I, Item I for additional information relating to the merger.

PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

ICG Litigation

On December 28, 2006, AE Supply and MP filed a complaint in the Court of Common Pleas of Allegheny County, Pennsylvania against International Coal Group, Inc. (ICG), Anker West Virginia Mining Company, Inc. (Anker WV), and Anker Coal Group, Inc. (Anker Coal). Anker WV, now known as Wolf Mining Company, entered into a long term Coal Sales Agreement with AE Supply and MP for the supply of coal to the Harrison generating facility. Anker Coal, now known as Hunter Ridge Holdings Inc., guaranteed performance under the contract. Prior to the time of trial, ICG was dismissed as a defendant by the Court, which issue can be the subject of a future appeal. As a result of defendants past and continued failure to supply the contracted coal, AE Supply and MP have incurred and will continue to incur significant additional costs for purchasing replacement coal. A non-jury trial was held on January 10, 2011 through February 1, 2011. At trial, AE Supply and MP presented evidence that they have incurred damages for replacement coal purchased through the end of 2010 and will incur additional damages for future shortfalls. The total damages claimed were in excess of $150 million. Defendants primarily claim that their performance is excused under a force majeure clause in the coal sales agreement and presented evidence at trial that they will continue to not provide the contracted yearly tonnage amounts. On May 2, 2011, the court entered a verdict in favor of AE Supply and MP for $104 million, which may be challenged in post-trial filings and an appeal.

Additional Information required for Part II, Item 1 is incorporated by reference to the discussions in Notes 10 and 11 of the Consolidated Financial Statements in Part I, Item 1 of this Form 10-Q.

ITEM 1A. RISK FACTORS

FirstEnergy s Annual Report on Form 10-K for the year ended December 31, 2010, includes a detailed discussion of its risk factors. In connection with the recent acquisition of Allegheny and the current events in Japan, the information presented below updates and supplements the risk factors appearing in our annual Report on Form 10-K for the year ended December 31, 2010.

Potential NRC Regulation in Response to the Incident at Japan s Fukushima Daiichi Nuclear Plant

As a result of the NRC s investigation of the incident at the Fukushima Daiichi nuclear plant, potential exists for the NRC to promulgate new or revised requirements with respect to nuclear plants located in the United States, which could necessitate additional expenditures at our nuclear plants. It is also possible that the NRC could suspend or otherwise delay pending nuclear relicensing proceedings, including the Davis-Besse relicensing proceeding. FirstEnergy cannot currently estimate the impact of any such regulatory actions on its financial condition or results of operations.

Risks Associated With Our Recently Completed Merger

Our Merger with AE May Not Achieve Its Intended Results.

We entered into the merger agreement with AE with the expectation that the merger would result in various benefits, including, among other things, cost savings and operating efficiencies relating to the regulated segments and the unregulated competitive segment. Our ability to achieve the anticipated benefits of the merger is subject to a number of uncertainties, including whether the business of Allegheny is integrated in an efficient and effective manner and maintenance of the current credit ratings of the combined company and its subsidiaries. Failure to achieve these anticipated benefits could result in increased costs, decreases in the amount of expected revenues generated by the combined company and diversion of management s time and energy and could have an adverse effect on the combined company s business, financial results and prospects.

As a Result of the Merger We Will be Subject to Business Uncertainties That Could Adversely Affect Our Financial Results.

Although we are taking steps designed to reduce any adverse effects, uncertainty about the effect of the merger with AE on employees and customers may have an adverse effect on us. Employee retention and recruitment may be particularly challenging, as employees and prospective employees may experience uncertainty about their future roles with the combined company. Despite our retention and recruiting efforts, key employees may depart or fail to accept employment with us because of issues relating to the uncertainty and difficulty of integration or a desire not to remain with the combined company. Additionally, customers, suppliers and others that deal with us may seek to change existing relationships.

Furthermore, the integration of Allegheny into our company may place a significant burden on management and internal resources. The diversion of management attention away from day-to-day business concerns and any difficulties encountered in the transition and integration process could affect our financial results. In each case, our business results could be affected.

The Combined Company Will Have a Higher Percentage of Coal-Fired Generation Capacity Compared to FirstEnergy s Previous Generation Mix. As a Result, FirstEnergy May Be Exposed to Greater Risk from Regulations of Coal and Coal Combustion By-Products Than it Faced Prior to the Merger

The combined company s generation fleet has a higher percentage of coal-fired generation capacity compared to FirstEnergy s previous generation mix. As a result, FirstEnergy s exposure to new or changing legislation, regulation or other legal requirements related to greenhouse gas or other emissions may be increased compared to its previous exposure. Approximately 52% of FirstEnergy s pre-merger generation fleet capacity was coal-fired, with the remainder being low-emitting natural gas, oil fired or non-emitting nuclear and pumped storage. Approximately 78% of Allegheny s generation fleet capacity is coal-fired. Approximately 62% of the combined company s fleet capacity is coal-fired. Historically, coal-fired generating plants face greater exposure to the costs of complying with federal, state and local environmental statutes, rules and regulations relating to emissions of substances such as sulfur dioxide, nitrogen oxide and mercury. In addition, there are currently a number of federal, state and international initiatives under consideration to, among other things, require reductions in greenhouse gas emissions from power generation or other facilities and to regulate coal combustion by-products, such as coal ash, as hazardous waste. These legal requirements and initiatives could require substantial additional costs, extensive mitigation efforts and, in the case of greenhouse gas legislation, could raise uncertainty about the future viability of fossil fuels as an energy source for new and existing electric generation facilities. Failure to comply with any such existing or future legal requirements may also result in the assessment of fines and penalties. Significant resources also may be expended to defend against allegations of violations of any such requirements. FirstEnergy expects approximately 70% of its generation fleet to be non-emitting or low-emitting by the end of 2011. All of Allegheny s supercritical coal-fired generation assets are scrubbed, and its generation portfolio also includes pumped storage and natural gas generation capacity. The combined company s generation fleet nevertheless could face greater exposure to risks relating to the foregoing legal requirements than FirstEnergy s pre-merger fleet due to the combined company s increased percentage of coal-fired generation facilities.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

(c) FirstEnergy

The table below includes information on a monthly basis regarding purchases made by FirstEnergy of its common stock during the first quarter of 2011.

	Period			
	January	**February**	**March**	**First Quarter**
Total Number of Shares Purchased[(a)]	32,053	543,138	1,344,212	1,919,403
Average Price Paid per Share	$ 38.36	$ 38.44	$ 37.55	$ 37.81
Total Number of Shares Purchased As Part of Publicly Announced Plans or Programs				
Maximum Number (or Approximate Dollar Value) of Shares that May Yet Be Purchased Under the Plans or Programs				

(a) Share amounts reflect purchases on the open market to satisfy FirstEnergy s obligations to deliver common stock for some or all of the following: 2007 Incentive Plan, Deferred Compensation Plan for Outside Directors, Executive Deferred Compensation Plan, Savings Plan, Director Compensation, Allegheny Energy, Inc. 1998 Long-Term Incentive Plan, Allegheny Energy, Inc. 2008 Long-Term Incentive Plan, Allegheny Energy, Inc, Non-Employee Director Stock Plan, Allegheny Energy, Inc, amended and Restated Revised Plan for Deferral of Compensation of Directors, and Stock Investment Plan.

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ITEM 5. OTHER INFORMATION

Signal Peak Mine Safety

FirstEnergy, through its FEV wholly-owned subsidiary, has a 50% interest in Global Mining Group LLC, a joint venture that owns Signal Peak which is a company that constructed and operates the Bull Mountain Mine No. 1 (Mine), an underground coal mine near Roundup, Montana. The operation of the Mine is subject to regulation by the Federal Mine Safety and Health Administration (MSHA) under the Federal Mine Safety and Health Act of 1977 (Mine Act).

Section 1503 of the Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act), which was enacted on July 21, 2010, contains new reporting requirements regarding mine safety, including, to the extent applicable, disclosing in periodic reports filed under the Securities Exchange Act of 1934 the receipt of certain notifications from the MSHA.

On November 19, 2010, Signal Peak received a letter from MSHA placing it on notice that the Mine has a potential pattern of violations of mandatory health or safety standards under Section 104(e) of the Mine Act. If implemented, Section 104(e) requires all subsequent violations designated as Significant and Substantial be issued as closure orders with all persons withdrawn from the affected area except those necessary to correct the violation. On March 16, 2011, Signal Peak Mine received a letter from MSHA indicating that the mine is no longer being considered for a pattern of potential violations notice.

Signal Peak received the following notices of violation and proposed assessments for the Mine under the Mine Act during the three months ended March 31, 2011:

	Signal Peak
Number of significant and substantial violations of mandatory health or safety standards under 104*	22
Number of orders issued under 104(b)*	
Number of citations and orders for unwarrantable failure to comply with mandatory health or safety standards under 104(d)*	
Number of flagrant violations under 110(b)(2)*	
Number of imminent danger orders issued under 107(a)*	
MSHA written notices under Mine Act section 104(e)* of a pattern of violation of mandatory health or safety standards or of the potential to have such a pattern	
Pending Mine Safety Commission legal actions (including any contested citations issued)	13
Number of mining related fatalities	
Total dollar value of proposed assessments	$ 1,892

* References to sections under Mine Act

The inclusion of this information in this report is not an admission by FirstEnergy that it controls Signal Peak or that Signal Peak is FirstEnergy s subsidiary for purposes of Section 1503 or for any other purpose,

More detailed information about the Mine, including safety-related data, can be found at MSHA s website, www.MSHA.gov. Signal Peak operates the Mine under the MSHA identification number 2401950.

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ITEM 6. EXHIBITS

Exhibit Number

FirstEnergy

3.1	Amendment to the Amended Articles of Incorporation of FirstEnergy Corp. dated as of February 25, 2011 (incorporated by reference to FirstEnergy s Form 8-K filed February 25, 2011, Exhibit 3.1, File No. 21011)
10.1	Allegheny Energy, Inc. 1998 Long-Term Incentive Plan (incorporated by reference to FirstEnergy s Form 8-K filed February 25, 2011, Exhibit 10.2, File No. 21011)
10.2	Allegheny Energy, Inc. 2008 Long-Term Incentive Plan (incorporated by reference to FirstEnergy s Form 8-K filed February 25, 2011, Exhibit 10.3, File No. 21011)
10.3	Allegheny Energy, Inc. Non-Employee Director Stock Plan (incorporated by reference to FirstEnergy s Form 8-K filed February 25, 2011, Exhibit 10.4, File No. 21011)
10.4	Allegheny Energy, Inc. Amended and Restated Revised Plan for Deferral of Compensation of directors (incorporated by reference to FirstEnergy s Form 8-K filed February 25, 2011, Exhibit 10.5, File No. 21011)
10.5	Amendment to FirstEnergy Corp. 2007 Incentive Compensation Plan, effective January 1, 2011
10.6	Amendment to FirstEnergy Corp. Executive Deferred Compensation Plan, effective January 1, 2012
10.7	Amendment to FirstEnergy Corp. Deferred Compensation Plan for Outside Directors, effective January 1, 2012
10.8	Amendment to FirstEnergy Corp. Supplemental Executive Retirement Plan, effective January 1, 2012
10.9	FirstEnergy Corp. Change in Control Severance Plan
10.10	Amendment to Employment Agreement, dated February 25, 2011, between FirstEnergy Service Company and Gary R. Leidich
12	Fixed charge ratios
31.1	Certification of chief executive officer, as adopted pursuant to Rule 13a-14(a)
31.2	Certification of chief financial officer, as adopted pursuant to Rule 13a-14(a)
32	Certification of chief executive officer and chief financial officer, pursuant to 18 U.S.C. Section 1350

101*	The following materials from the Quarterly Report on Form 10-Q of FirstEnergy Corp. for the period ended March 31, 2011, formatted in XBRL (extensible Business Reporting Language): (i) Consolidated Statements of Income and Comprehensive Income, (ii) Consolidated Balance Sheets, (iii) Consolidated Statements of Cash Flows, (iv) related notes to these financial statements tagged as blocks of text and (v) document and entity information.

FES

10.1	Asset Purchase Agreement dated as of March 11, 2011 by and between FirstEnergy Generation Corp. and American Municipal Power, Inc.
12	Fixed charge ratios
31.1	Certification of chief executive officer, as adopted pursuant to Rule 13a-14(a)
31.2	Certification of chief financial officer, as adopted pursuant to Rule 13a-14(a)
32	Certification of chief executive officer and chief financial officer, pursuant to 18 U.S.C. Section 1350

OE

12	Fixed charge ratios
31.1	Certification of chief executive officer, as adopted pursuant to Rule 13a-14(a)
31.2	Certification of chief financial officer, as adopted pursuant to Rule 13a-14(a)
32	Certification of chief executive officer and chief financial officer, pursuant to 18 U.S.C. Section 1350

CEI

12	Fixed charge ratios
31.1	Certification of chief executive officer, as adopted pursuant to Rule 13a-14(a)
31.2	Certification of chief financial officer, as adopted pursuant to Rule 13a-14(a)
32	Certification of chief executive officer and chief financial officer, pursuant to 18 U.S.C. Section 1350

TE

12	Fixed charge ratios
31.1	Certification of chief executive officer, as adopted pursuant to Rule 13a-14(a)
31.2	Certification of chief financial officer, as adopted pursuant to Rule 13a-14(a)
32	Certification of chief executive officer and chief financial officer, pursuant to 18 U.S.C. Section 1350

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JCP&L

12	Fixed charge ratios
31.1	Certification of chief executive officer, as adopted pursuant to Rule 13a-14(a)
31.2	Certification of chief financial officer, as adopted pursuant to Rule 13a-14(a)
32	Certification of chief executive officer and chief financial officer, pursuant to 18 U.S.C. Section 1350

Met-Ed

12	Fixed charge ratios
31.1	Certification of chief executive officer, as adopted pursuant to Rule 13a-14(a)
31.2	Certification of chief financial officer, as adopted pursuant to Rule 13a-14(a)
32	Certification of chief executive officer and chief financial officer, pursuant to 18 U.S.C. Section 1350

Penelec

12	Fixed charge ratios
31.1	Certification of chief executive officer, as adopted pursuant to Rule 13a-14(a)
31.2	Certification of chief financial officer, as adopted pursuant to Rule 13a-14(a)
32	Certification of chief executive officer and chief financial officer, pursuant to 18 U.S.C. Section 1350

* Users of these data are advised pursuant to Rule 401 of Regulation S-T that the financial information contained in the XBRL-Related Documents is unaudited and, as a result, investors should not rely on the XBRL-Related Documents in making investment decisions. Furthermore, users of these data are advised in accordance with Rule 406T of Regulation S-T promulgated by the Securities and Exchange Commission that this Interactive Data File is deemed not filed or part of a registration statement or prospectus for purposes of sections 11 or 12 of the Securities Act of 1933, as amended, is deemed not filed for purposes of section 18 of the Securities Exchange Act of 1934, as amended, and otherwise is not subject to liability under these sections.

Pursuant to reporting requirements of respective financings, FirstEnergy, FES, OE, CEI, TE, JCP&L, Met-Ed and Penelec are required to file fixed charge ratios as an exhibit to this Form 10-Q.

Pursuant to paragraph (b)(4)(iii)(A) of Item 601 of Regulation S-K, neither FirstEnergy, FES, OE, CEI, TE, JCP&L, Met-Ed nor Penelec have filed as an exhibit to this Form 10-Q any instrument with respect to long-term debt if the respective total amount of securities authorized thereunder does not exceed 10% of its respective total assets, but each hereby agrees to furnish to the SEC on request any such documents.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, each Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

May 3, 2011

FIRSTENERGY CORP.

Registrant

FIRSTENERGY SOLUTIONS CORP.

Registrant

OHIO EDISON COMPANY

Registrant

THE CLEVELAND ELECTRIC ILLUMINATING COMPANY

Registrant

THE TOLEDO EDISON COMPANY

Registrant

METROPOLITAN EDISON COMPANY

Registrant

PENNSYLVANIA ELECTRIC COMPANY

Registrant

/s/ Harvey L. Wagner

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

JERSEY CENTRAL POWER & LIGHT COMPANY

Registrant

/s/ K. Jon Taylor

K. Jon Taylor
Controller
(Principal Accounting Officer)