CLEVELAND ELECTRIC ILLUMINATING CO
Form 10-Q
August 02, 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 June 30, 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. 76 South Main Street Akron, OH 44308	34-4375005

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., 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 JULY 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-l 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.
- 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, including the Cross-State Air Pollution Rule (CSAPR), 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 with respect to our nuclear operations (including, but not limited to the revocation or non-renewal of necessary licenses, approvals or operating permits 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 ability to recover certain transmission costs through their transmission service charge riders.
- The continuing availability of generating units and changes in their ability to operate at or near full capacity.
- Replacement power costs being higher than anticipated or inadequately hedged.
- 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 FirstEnergy s nuclear decommissioning trusts, pension trusts and other trust funds, and cause us 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 FirstEnergy and its subsidiaries.

- Changes in general economic conditions affecting FirstEnergy and its subsidiaries.
- Interest rates and any actions taken by credit rating agencies that could negatively affect FirstEnergy s and its subsidiaries 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 FirstEnergy s and its subsidiaries major industrial and commercial customers.
- Issues concerning the soundness of financial institutions and counterparties with which FirstEnergy and its 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
AET	Allegheny Energy Transmission, LLC, a parent of TrAIL and PATH
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
ARR	Auction Revenue Rights
BGS	Basic Generation Service
BMP	Bruce Mansfield Plant
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CATR	Clean Air Transport Rule
CBP	Competitive Bid Process

GLOSSARY OF TERMS, Cont d.

CCB	Coal Combustion By-products
CDWR	California Department of Water Resources
CO_2	Carbon Dioxide
CSAPR	Cross-State Air Pollution Rule
CTC	Competitive Transition Charge
CWA	Clean Water Act
CWIP	Construction Work in Progress
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
LBR	Little Blue Run
LED	Light-Emitting Diode
LOC	Letter of Credit
LSE	Load Serving Entity
LTIP	Long-Term Incentive Plan
MACT	Maximum Achievable Control Technology
MDE	Maryland Department of the Environment
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

MVP	Multi-value Project
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
NPDES	National Pollutant Discharge Elimination System
NRC	Nuclear Regulatory Commission

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GLOSSARY OF TERMS, Cont d.

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
OSBA	Office of Small Business Advocate
OVEC	Ohio Valley Electric Corporation
PA DEP	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
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
RPM	Reliability Pricing Model
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 June 30 2011	Three Months Ended June 30 2010	Six Months Ended June 30 2011	Six Months Ended June 30 2010
REVENUES:				
Electric utilities	$ 2,590	$ 2,373	$ 4,925	$ 4,916
Unregulated businesses	1,470	766	2,711	1,522
Total revenues*	4,060	3,139	7,636	6,438
EXPENSES:				
Fuel	635	350	1,088	684
Purchased power	1,220	1,063	2,406	2,301
Other operating expenses	1,105	673	2,138	1,374
Provision for depreciation	282	190	502	383
Amortization of regulatory assets	90	161	222	373
General taxes	242	176	479	381
Total expenses	3,574	2,613	6,835	5,496
OPERATING INCOME	486	526	801	942
OTHER INCOME (EXPENSE):				
Investment income	31	31	52	47
Interest expense	(265)	(207)	(496)	(420)
Capitalized interest	20	40	38	81
Total other expense	(214)	(136)	(406)	(292)
INCOME BEFORE INCOME TAXES	272	390	395	650
INCOME TAXES	101	134	179	245
NET INCOME	171	256	216	405
Loss attributable to noncontrolling interest	(10)	(9)	(15)	(15)
EARNINGS AVAILABLE TO FIRSTENERGY CORP.	$ 181	$ 265	$ 231	$ 420

EARNINGS PER SHARE OF COMMON STOCK:				
Basic	$ 0.43	$ 0.87	$ 0.61	$ 1.38
Diluted	$ 0.43	$ 0.87	$ 0.61	$ 1.37
AVERAGE SHARES OUTSTANDING:				
Basic	418	304	380	304
Diluted	420	305	382	305
DIVIDENDS DECLARED PER SHARE OF COMMON STOCK			$ 0.55	$ 0.55

* Includes excise tax collections of $116 million and $99 million in the three months ended June 30, 2011 and 2010, respectively, and $235 million and $208 million in the six months ended June 30, 2011 and 2010, respectively.

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 COMPREHENSIVE INCOME
(Unaudited)

(In millions)	Three Months Ended June 30 2011	Three Months Ended June 30 2010	Six Months Ended June 30 2011	Six Months Ended June 30 2010
NET INCOME	$ 171	$ 256	$ 216	$ 405
OTHER COMPREHENSIVE INCOME:				
Pension and other postretirement benefits	111	17	130	30
Unrealized gain on derivative hedges	17	6	11	10
Change in unrealized gain on available-for-sale securities	10	6	19	12
Other comprehensive income	138	29	160	52
Income tax expense related to other comprehensive income	53	9	54	16
Other comprehensive income, net of tax	85	20	106	36
COMPREHENSIVE INCOME	256	276	322	441
COMPREHENSIVE LOSS ATTRIBUTABLE TO NONCONTROLLING INTEREST	(10)	(9)	(15)	(15)
COMPREHENSIVE INCOME AVAILABLE TO FIRSTENERGY CORP.	$ 266	$ 285	$ 337	$ 456

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

FIRSTENERGY CORP.
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions)	June 30, 2011	December 31, 2010
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 476	$ 1,019
Receivables-		
Customers, net of allowance for uncollectible accounts of $35 in 2011 and $36 in 2010	1,578	1,392
Other, net of allowance for uncollectible accounts of $8 in 2011 and 2010	256	176
Materials and supplies, at average cost	866	638
Prepaid taxes	474	199
Derivatives	265	182
Other	203	92
	4,118	3,698
PROPERTY, PLANT AND EQUIPMENT:		
In service	39,568	29,451
Less Accumulated provision for depreciation	11,593	11,180
	27,975	18,271
Construction work in progress	1,465	1,517
Property, plant and equipment held for sale, net	502	
	29,942	19,788
INVESTMENTS:		
Nuclear plant decommissioning trusts	2,051	1,973
Investments in lease obligation bonds	414	476
Nuclear fuel disposal trust	212	208
Other	479	345
	3,156	3,002
DEFERRED CHARGES AND OTHER ASSETS:		
Goodwill	6,456	5,575
Regulatory assets	2,182	1,826
Intangible assets	973	256
Other	769	660
	10,380	8,317
	$ 47,596	$ 34,805

LIABILITIES AND CAPITALIZATION

CURRENT LIABILITIES:				
Currently payable long-term debt	$	2,058	$	1,486
Short-term borrowings		656		700
Accounts payable		1,122		872
Accrued taxes		399		326
Accrued compensation and benefits		331		315
Derivatives		287		266
Other		691		733
		5,544		4,698
CAPITALIZATION:				
Common stockholders equity-				
Common stock, $0.10 par value, authorized 490,000,000 and 375,000,000 shares, respectively- 418,216,437 and 304,835,407 shares outstanding, respectively		42		31
Other paid-in capital		9,782		5,444
Accumulated other comprehensive loss		(1,433)		(1,539)
Retained earnings		4,607		4,609
Total common stockholders equity		12,998		8,545
Noncontrolling interest		(48)		(32)
Total equity		12,950		8,513
Long-term debt and other long-term obligations		16,491		12,579
		29,441		21,092
NONCURRENT LIABILITIES:				
Accumulated deferred income taxes		5,219		2,879
Retirement benefits		2,134		1,868
Asset retirement obligations		1,459		1,407
Deferred gain on sale and leaseback transaction		942		959
Adverse power contract liability		649		466
Other		2,208		1,436
		12,611		9,015
COMMITMENTS, GUARANTEES AND CONTINGENCIES (Note 9)				
	$	47,596	$	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)	Six Months Ended June 30 2011	2010
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net Income	$ 216	$ 405
Adjustments to reconcile net income to net cash from operating activities-		
Provision for depreciation	502	383
Amortization of regulatory assets	222	373
Nuclear fuel and lease amortization	92	76
Deferred purchased power and other costs	(168)	(146)
Deferred income taxes and investment tax credits, net	552	159
Deferred rents and lease market valuation liability	(61)	(62)
Accrued compensation and retirement benefits	49	(27)
Commodity derivative transactions, net	(21)	(29)
Pension trust contribution	(262)	
Asset impairments	41	21
Cash collateral paid, net	(31)	(63)
Interest rate swap transactions		43
Decrease (increase) in operating assets-		
Receivables	199	(156)
Materials and supplies	24	(17)
Prepayments and other current assets	(268)	(81)
Increase (decrease) in operating liabilities-		
Accounts payable	(28)	18
Accrued taxes	(66)	(58)
Accrued interest	(4)	10
Other	43	9
Net cash provided from operating activities	1,031	858
CASH FLOWS FROM FINANCING ACTIVITIES:		
New Financing-		
Long-term debt	503	
Short-term borrowings, net		281
Redemptions and Repayments-		
Long-term debt	(1,002)	(407)
Short-term borrowings, net	(44)	
Common stock dividend payments	(420)	(335)
Other	(76)	(23)
Net cash used for financing activities	(1,039)	(484)

CASH FLOWS FROM INVESTING ACTIVITIES:				
Property additions		(1,018)		(997)
Proceeds from asset sales				116
Sales of investment securities held in trusts		1,703		1,915
Purchases of investment securities held in trusts		(1,807)		(1,934)
Customer acquisition costs		(2)		(105)
Cash investments		50		59
Cash received in Allegheny merger		590		
Other		(51)		(21)
Net cash used for investing activities		(535)		(967)
Net change in cash and cash equivalents		(543)		(593)
Cash and cash equivalents at beginning of period		1,019		874
Cash and cash equivalents at end of period	$	476	$	281
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 June 30		Six Months Ended June 30	
(In millions)	2011	2010	2011	2010
STATEMENTS OF INCOME				
REVENUES:				
Electric sales to non-affiliates	$ 1,052	$ 729	$ 2,097	$ 1,397
Electric sales to affiliates	170	539	431	1,146
Other	70	58	156	171
Total revenues	1,292	1,326	2,684	2,714
EXPENSES:				
Fuel	316	343	659	671
Purchased power from affiliates	65	69	134	130
Purchased power from non-affiliates	329	310	626	760
Other operating expenses	429	304	910	608
Provision for depreciation	68	63	136	126
General taxes	30	22	60	49
Impairment of long-lived assets	7		20	2
Total expenses	1,244	1,111	2,545	2,346
OPERATING INCOME	48	215	139	368
OTHER INCOME (EXPENSE):				
Investment income	16	13	22	14
Miscellaneous income (expense)	4	4	8	7
Interest expense affiliates	(2)	(2)	(3)	(5)
Interest expense other	(52)	(51)	(105)	(101)
Capitalized interest	10	24	20	44
Total other expense	(24)	(12)	(58)	(41)
INCOME BEFORE INCOME TAXES	24	203	81	327
INCOME TAXES	4	69	25	113
NET INCOME	$ 20	$ 134	$ 56	$ 214

STATEMENTS OF COMPREHENSIVE INCOME

NET INCOME	$ 20	$ 134	$ 56	$ 214
OTHER COMPREHENSIVE INCOME:				
Pension and other postretirement benefits	1	1	3	(9)
Unrealized gain on derivative hedges	14	3	5	4
Change in unrealized gain on available-for-sale securities	8	6	15	11
Other comprehensive income	23	10	23	6
Income taxes related to other comprehensive income	10	4	8	2
Other comprehensive income, net of tax	13	6	15	4
COMPREHENSIVE INCOME	$ 33	$ 140	$ 71	$ 218

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

FIRSTENERGY SOLUTIONS CORP.

CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions)	June 30, 2011	December 31, 2010
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 6	$ 9
Receivables-		
Customers, net of allowance for uncollectible accounts of $18 in 2011 and $17 in 2010	450	366
Associated companies	490	478
Other, net of allowances for uncollectible accounts of $3 in 2011 and $7 in 2010	51	90
Notes receivable from associated companies	490	397
Materials and supplies, at average cost	499	545
Derivatives	221	182
Prepayments and other	49	59
	2,256	2,126
PROPERTY, PLANT AND EQUIPMENT:		
In service	11,455	11,321
Less Accumulated provision for depreciation	4,206	4,024
	7,249	7,297
Construction work in progress	694	1,063
Property, plant and equipment held for sale, net	487	
	8,430	8,360
INVESTMENTS:		
Nuclear plant decommissioning trusts	1,184	1,146
Other	10	12
	1,194	1,158
DEFERRED CHARGES AND OTHER ASSETS:		
Customer intangibles	129	134
Goodwill	24	24
Property taxes	41	41
Unamortized sale and leaseback costs	76	73
Derivatives	135	98
Other	75	48
	480	418

	$ 12,360	$ 12,062
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Currently payable long-term debt	$ 1,088	$ 1,132
Short-term borrowings-		
Associated companies	541	12
Other	1	
Accounts payable-		
Associated companies	393	467
Other	191	241
Derivatives	242	266
Other	262	322
	2,718	2,440
CAPITALIZATION:		
Common stockholder s equity-		
Common stock, without par value, authorized 750 shares- 7 shares outstanding	1,488	1,490
Accumulated other comprehensive loss	(105)	(120)
Retained earnings	2,474	2,418
Total common stockholder s equity	3,857	3,788
Long-term debt and other long-term obligations	3,000	3,181
	6,857	6,969
NONCURRENT LIABILITIES:		
Deferred gain on sale and leaseback transaction	942	959
Accumulated deferred income taxes	216	58
Asset retirement obligations	875	892
Retirement benefits	295	285
Lease market valuation liability	194	217
Derivatives	85	81
Other	178	161
	2,785	2,653
COMMITMENTS, GUARANTEES AND CONTINGENCIES (Note 9)		
	$ 12,360	$ 12,062

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

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

(In millions)	Six Months Ended June 30 2011	2010
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net Income	$ 56	$ 214
Adjustments to reconcile net income to net cash from operating activities-		
Provision for depreciation	136	126
Nuclear fuel and lease amortization	92	78
Deferred rents and lease market valuation liability	(58)	(59)
Deferred income taxes and investment tax credits, net	126	114
Asset impairments	28	21
Accrued compensation and retirement benefits	8	7
Commodity derivative transactions, net	(60)	(29)
Cash collateral paid, net	(40)	(38)
Decrease (increase) in operating assets-		
Receivables	(36)	(193)
Materials and supplies	50	(29)
Prepayments and other current assets	12	25
Decrease in operating liabilities-		
Accounts payable	(124)	(32)
Accrued taxes	(29)	(8)
Other	21	21
Net cash provided from operating activities	182	218
CASH FLOWS FROM FINANCING ACTIVITIES:		
New financing-		
Long-term debt	247	
Short-term borrowings, net	530	76
Redemptions and repayments-		
Long-term debt	(472)	(295)
Other	(11)	(1)
Net cash provided from (used for) financing activities	294	(220)
CASH FLOWS FROM INVESTING ACTIVITIES:		
Property additions	(334)	(566)
Proceeds from asset sales		116
Sales of investment securities held in trusts	513	957
Purchases of investment securities held in trusts	(545)	(979)
Loans to associated companies, net	(93)	631
Customer acquisition costs	(2)	(105)

Leasehold improvement payments to associated companies				(51)
Other		(18)		(1)
Net cash provided from (used for) investing activities		(479)		2
Net change in cash and cash equivalents		(3)		
Cash and cash equivalents at beginning of period		9		
Cash and cash equivalents at end of period	$	6	$	

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)

	Three Months Ended June 30		Six Months Ended June 30	
(In thousands)	**2011**	**2010**	**2011**	**2010**
STATEMENTS OF INCOME				
REVENUES:				
Electric sales	$ 360,203	$ 415,437	$ 724,034	$ 895,362
Excise and gross receipts tax collections	24,941	23,949	53,136	52,424
Total revenues	385,144	439,386	777,170	947,786
EXPENSES:				
Purchased power from affiliates	69,134	134,050	162,396	287,727
Purchased power from non-affiliates	62,667	78,826	123,046	173,057
Other operating expenses	110,778	88,275	212,240	177,130
Provision for depreciation	22,470	22,014	44,346	43,894
Amortization of regulatory assets, net	2,405	9,424	3,179	38,769
General taxes	45,592	43,362	95,018	90,854
Total expenses	313,046	375,951	640,225	811,431
OPERATING INCOME	72,098	63,435	136,945	136,355
OTHER INCOME (EXPENSE):				
Investment income	5,043	6,309	9,351	11,553
Miscellaneous income (expense)	(477)	1,295	(187)	1,003
Interest expense	(22,011)	(22,155)	(44,156)	(44,465)
Capitalized interest	510	295	841	503
Total other expense	(16,935)	(14,256)	(34,151)	(31,406)
INCOME BEFORE INCOME TAXES	55,163	49,179	102,794	104,949
INCOME TAXES	16,538	11,856	34,029	31,465
NET INCOME	38,625	37,323	68,765	73,484
Income attributable to noncontrolling interest	114	130	230	262

EARNINGS AVAILABLE TO PARENT	$ 38,511	$ 37,193	$ 68,535	$ 73,222
STATEMENTS OF COMPREHENSIVE INCOME				
NET INCOME	$ 38,625	$ 37,323	$ 68,765	$ 73,484
OTHER COMPREHENSIVE INCOME:				
Pension and other postretirement benefits	1,122	322	1,461	4,337
Increase in unrealized gain on available-for-sale securities	1,591	520	1,569	811
Other comprehensive income	2,713	842	3,030	5,148
Income tax expense (benefit) related to other comprehensive income	386	(26)	(1,110)	667
Other comprehensive income, net of tax	2,327	868	4,140	4,481
COMPREHENSIVE INCOME	40,952	38,191	72,905	77,965
COMPREHENSIVE INCOME ATTRIBUTABLE TO NONCONTROLLING INTEREST	114	130	230	262
COMPREHENSIVE INCOME AVAILABLE TO PARENT	$ 40,838	$ 38,061	$ 72,675	$ 77,703

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)	June 30, 2011	December 31, 2010
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 176	$ 420,489
Receivables-		
Customers, net of allowance for uncollectible accounts of $3,564 in 2011 and $4,086 in 2010	159,393	176,591
Associated companies	68,709	118,135
Other	32,798	12,232
Notes receivable from associated companies	95,884	16,957
Prepayments and other	35,339	6,393
	392,299	750,797
UTILITY PLANT:		
In service	3,176,455	3,136,623
Less Accumulated provision for depreciation	1,230,570	1,207,745
	1,945,885	1,928,878
Construction work in progress	66,656	45,103
	2,012,541	1,973,981
OTHER PROPERTY AND INVESTMENTS:		
Investment in lease obligation bonds	177,835	190,420
Nuclear plant decommissioning trusts	133,354	127,017
Other	92,440	95,563
	403,629	413,000
DEFERRED CHARGES AND OTHER ASSETS:		
Regulatory assets	392,580	400,322
Pension assets	62,612	28,596
Property taxes	71,331	71,331
Unamortized sale and leaseback costs	27,628	30,126
Other	19,041	17,634
	573,192	548,009
	$ 3,381,661	$ 3,685,787
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		

Currently payable long-term debt	$ 1,429	$ 1,419
Short-term borrowings-		
Associated companies		142,116
Other	166	320
Accounts payable-		
Associated companies	94,821	99,421
Other	41,417	29,639
Accrued taxes	69,364	78,707
Accrued interest	25,374	25,382
Other	79,795	74,947
	312,366	451,951
CAPITALIZATION:		
Common stockholder s equity-		
Common stock, without par value, authorized 175,000,000 shares 60 shares outstanding	783,871	951,866
Accumulated other comprehensive loss	(174,936)	(179,076)
Retained earnings	110,156	141,621
Total common stockholder s equity	719,091	914,411
Noncontrolling interest	5,313	5,680
Total equity	724,404	920,091
Long-term debt and other long-term obligations	1,151,720	1,152,134
	1,876,124	2,072,225
NONCURRENT LIABILITIES:		
Accumulated deferred income taxes	749,687	696,410
Accumulated deferred investment tax credits	9,439	10,159
Retirement benefits	183,345	183,712
Asset retirement obligations	69,164	74,456
Other	181,536	196,874
	1,193,171	1,161,611
COMMITMENTS AND CONTINGENCIES (Note 9)		
	$ 3,381,661	$ 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)	Six Months Ended June 30 2011	2010
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net Income	$ 68,765	$ 73,484
Adjustments to reconcile net income to net cash from operating activities-		
Provision for depreciation	44,346	43,894
Amortization of regulatory assets, net	3,179	38,769
Purchased power cost recovery reconciliation	(8,584)	(1,514)
Amortization of lease costs	(4,696)	(4,619)
Deferred income taxes and investment tax credits, net	62,216	4,964
Accrued compensation and retirement benefits	(8,328)	(16,154)
Accrued regulatory obligations	(3,309)	(2,309)
Cash collateral from (to) suppliers, net	(850)	1,215
Pension trust contribution	(27,000)	
Decrease (increase) in operating assets-		
Receivables	80,968	49,250
Prepayments and other current assets	(28,947)	5,072
Decrease in operating liabilities-		
Accounts payable	(22,253)	(57,208)
Accrued taxes	(9,360)	(25,685)
Other	4,261	(114)
Net cash provided from operating activities	150,408	109,045
CASH FLOWS FROM FINANCING ACTIVITIES:		
Redemptions and Repayments-		
Long-term debt	(707)	(2,957)
Short-term borrowings, net	(142,270)	(93,017)
Common stock dividend payments	(268,000)	(250,000)
Other	(2,340)	(881)
Net cash used for financing activities	(413,317)	(346,855)
CASH FLOWS FROM INVESTING ACTIVITIES:		
Property additions	(78,894)	(71,698)
Leasehold improvement payments from associated companies		18,375
Sales of investment securities held in trusts	19,595	59,804
Purchases of investment securities held in trusts	(25,547)	(64,063)
Loans to associated companies, net	(78,927)	12,420
Cash investments	11,962	11,774
Other	(5,593)	(1,298)

Net cash used for investing activities	(157,404)	(34,686)
Net change in cash and cash equivalents	(420,313)	(272,496)
Cash and cash equivalents at beginning of period	420,489	324,175
Cash and cash equivalents at end of period	$ 176	$ 51,679

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 June 30		Six Months Ended June 30	
(In thousands)	**2011**	**2010**	**2011**	**2010**
STATEMENTS OF INCOME				
REVENUES:				
Electric sales	$ 202,148	$ 280,180	$ 408,890	$ 592,677
Excise tax collections	15,706	15,495	33,851	33,068
Total revenues	217,854	295,675	442,741	625,745
EXPENSES:				
Purchased power from affiliates	36,040	99,422	82,208	208,815
Purchased power from non-affiliates	23,099	32,651	41,319	70,049
Other operating expenses	31,625	28,937	66,661	60,172
Provision for depreciation	18,488	18,336	36,914	36,447
Amortization of regulatory assets, net	18,166	30,807	41,536	75,946
General taxes	36,954	28,840	77,166	67,329
Total expenses	164,372	238,993	345,804	518,758
OPERATING INCOME	53,482	56,682	96,937	106,987
OTHER INCOME (EXPENSE):				
Investment income	5,637	6,605	12,234	14,152
Miscellaneous income	1,038	675	1,674	1,257
Interest expense	(32,135)	(33,262)	(65,213)	(66,883)
Capitalized interest	36	7	63	33
Total other expense	(25,424)	(25,975)	(51,242)	(51,441)
INCOME BEFORE INCOME TAXES	28,058	30,707	45,695	55,546
INCOME TAXES	6,209	8,785	10,645	19,628
NET INCOME	21,849	21,922	35,050	35,918
Income attributable to noncontrolling interest	309	366	675	785

EARNINGS AVAILABLE TO PARENT	$	21,540	$	21,556	$	34,375	$	35,133
STATEMENTS OF COMPREHENSIVE INCOME								
NET INCOME	$	21,849	$	21,922	$	35,050	$	35,918
OTHER COMPREHENSIVE INCOME (LOSS):								
Pension and other postretirement benefits (charges)		2,975		3,228		5,942		(19,357)
Income tax expense (benefit) related to other comprehensive income		860		976		398		(7,301)
Other comprehensive income (loss), net of tax		2,115		2,252		5,544		(12,056)
COMPREHENSIVE INCOME		23,964		24,174		40,594		23,862
COMPREHENSIVE INCOME ATTRIBUTABLE TO NONCONTROLLING INTEREST		309		366		675		785
COMPREHENSIVE INCOME AVAILABLE TO PARENT	$	23,655	$	23,808	$	39,919	$	23,077

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)	June 30, 2011	December 31, 2010
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 244	$ 238
Receivables-		
Customers, net of allowance for uncollectible accounts of $2,801 in 2011 and $4,589 in 2010	97,997	183,744
Associated companies	32,348	77,047
Other	13,476	11,544
Notes receivable from associated companies	71,911	23,236
Materials and supplies, at average cost	13,784	398
Prepayments and other	6,431	3,258
	236,191	299,465
UTILITY PLANT:		
In service	2,417,031	2,396,893
Less Accumulated provision for depreciation	944,379	932,246
	1,472,652	1,464,647
Construction work in progress	59,281	38,610
	1,531,933	1,503,257
OTHER PROPERTY AND INVESTMENTS:		
Investment in lessor notes	286,745	340,029
Other	10,048	10,074
	296,793	350,103
DEFERRED CHARGES AND OTHER ASSETS:		
Goodwill	1,688,521	1,688,521
Regulatory assets	320,337	370,403
Pension assets	14,652	
Property taxes	80,614	80,614
Other	12,884	11,486
	2,117,008	2,151,024
	$ 4,181,925	$ 4,303,849
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		

Currently payable long-term debt	$ 188	$ 161
Short-term borrowings from associated companies	23,303	105,996
Accounts payable-		
Associated companies	51,001	32,020
Other	18,700	14,947
Accrued taxes	83,265	84,668
Accrued interest	18,551	18,555
Other	38,685	44,569
	233,693	300,916
CAPITALIZATION:		
Common stockholder s equity-		
Common stock, without par value, authorized 105,000,000 shares, 67,930,743 shares outstanding	887,053	887,087
Accumulated other comprehensive loss	(147,643)	(153,187)
Retained earnings	539,280	568,906
Total common stockholder s equity	1,278,690	1,302,806
Noncontrolling interest	15,195	18,017
Total equity	1,293,885	1,320,823
Long-term debt and other long-term obligations	1,831,023	1,852,530
	3,124,908	3,173,353
NONCURRENT LIABILITIES:		
Accumulated deferred income taxes	640,059	622,771
Accumulated deferred investment tax credits	10,574	10,994
Retirement benefits	76,010	95,654
Other	96,681	100,161
	823,324	829,580
COMMITMENTS AND CONTINGENCIES (Note 9)		
	$ 4,181,925	$ 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)	Six Months Ended June 30 2011	2010
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net Income	$ 35,050	$ 35,918
Adjustments to reconcile net income to net cash from operating activities-		
Provision for depreciation	36,914	36,447
Amortization of regulatory assets, net	41,536	75,946
Deferred income taxes and investment tax credits, net	17,221	(18,083)
Accrued compensation and retirement benefits	5,421	5,421
Accrued regulatory obligations	(2,001)	(444)
Cash collateral from suppliers, net		685
Pension trust contribution	(35,000)	
Decrease (increase) in operating assets-		
Receivables	140,455	51,757
Prepayments and other current assets	(17,469)	5,392
Increase (decrease) in operating liabilities-		
Accounts payable	10,135	(34,488)
Accrued taxes	(346)	(11,317)
Other	(4,436)	2,023
Net cash provided from operating activities	227,480	149,257
CASH FLOWS FROM FINANCING ACTIVITIES:		
Redemptions and Repayments-		
Long-term debt	(74)	(54)
Short-term borrowings, net	(104,228)	(136,013)
Common stock dividend payments	(64,000)	(100,000)
Other	(5,239)	(3,367)
Net cash used for financing activities	(173,541)	(239,434)
CASH FLOWS FROM INVESTING ACTIVITIES:		
Property additions	(52,743)	(44,373)
Loans to associated companies, net	(48,676)	2,322
Redemptions of lessor notes	53,283	48,608
Other	(5,797)	(2,365)
Net cash provided from (used for) investing activities	(53,933)	4,192
Net change in cash and cash equivalents	6	(85,985)

Cash and cash equivalents at beginning of period		238		86,230
Cash and cash equivalents at end of period	$	244	$	245

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)

	Three Months Ended June 30		Six Months Ended June 30	
(In thousands)	**2011**	**2010**	**2011**	**2010**
STATEMENTS OF INCOME				
REVENUES:				
Electric sales	$ 93,048	$ 114,691	$ 199,373	$ 240,122
Excise tax collections	6,270	6,059	13,572	13,100
Total revenues	99,318	120,750	212,945	253,222
EXPENSES:				
Purchased power from affiliates	17,037	47,106	52,554	101,725
Purchased power from non-affiliates	16,114	15,223	30,102	33,713
Other operating expenses	32,549	25,499	69,136	51,044
Provision for depreciation	7,959	8,013	15,890	15,963
Deferral of regulatory assets, net	(7,054)	(1,800)	(18,532)	(10,299)
General taxes	12,438	12,282	26,890	25,743
Total expenses	79,043	106,323	176,040	217,889
OPERATING INCOME	20,275	14,427	36,905	35,333
OTHER INCOME (EXPENSE):				
Investment income	2,599	5,057	5,521	8,857
Miscellaneous income (expense)	396	(945)	(1,233)	(2,351)
Interest expense	(10,415)	(10,455)	(20,858)	(20,942)
Capitalized interest	135	80	237	158
Total other expense	(7,285)	(6,263)	(16,333)	(14,278)
INCOME BEFORE INCOME TAXES	12,990	8,164	20,572	21,055
INCOME TAXES	1,429	948	3,164	6,330
NET INCOME	11,561	7,216	17,408	14,725
Income attributable to noncontrolling interest	2	2	4	5

EARNINGS AVAILABLE TO PARENT	$ 11,559	$ 7,214	$ 17,404	$ 14,720
STATEMENTS OF COMPREHENSIVE INCOME				
NET INCOME	$ 11,561	$ 7,216	$ 17,408	$ 14,725
OTHER COMPREHENSIVE INCOME:				
Pension and other postretirement benefits	575	714	1,167	1,010
Increase (decrease) in unrealized gain on available-for-sale securities	754	(330)	2,059	39
Other comprehensive income	1,329	384	3,226	1,049
Income tax expense related to other comprehensive income	351	65	685	235
Other comprehensive income, net of tax	978	319	2,541	814
COMPREHENSIVE INCOME	12,539	7,535	19,949	15,539
COMPREHENSIVE INCOME ATTRIBUTABLE TO NONCONTROLLING INTEREST	2	2	4	5
COMPREHENSIVE INCOME AVAILABLE TO PARENT	$ 12,537	$ 7,533	$ 19,945	$ 15,534

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)	June 30, 2011	December 31, 2010
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 12	$ 149,262
Receivables-		
Customers, net of allowance for uncollectible accounts of $1,142 in 2011 and $1 in 2010	45,931	29
Associated companies	48,340	31,777
Other, net of allowance for uncollectible accounts of $339 in 2011 and $330 in 2010	5,272	18,464
Notes receivable from associated companies	128,815	96,765
Prepayments and other	12,052	2,306
	240,422	298,603
UTILITY PLANT:		
In service	955,002	947,203
Less Accumulated provision for depreciation	453,517	446,401
	501,485	500,802
Construction work in progress	17,386	12,604
	518,871	513,406
OTHER PROPERTY AND INVESTMENTS:		
Investment in lessor notes	82,153	103,872
Nuclear plant decommissioning trusts	79,018	75,558
Other	1,448	1,492
	162,619	180,922
DEFERRED CHARGES AND OTHER ASSETS:		
Goodwill	500,576	500,576
Regulatory assets	89,112	72,059
Pension assets	24,603	
Property taxes	24,990	24,990
Other	42,341	23,750
	681,622	621,375
	$ 1,603,534	$ 1,614,306

LIABILITIES AND CAPITALIZATION

CURRENT LIABILITIES:		
Currently payable long-term debt	$ 188	$ 199
Accounts payable-		
Associated companies	22,144	17,168
Other	12,524	7,351
Accrued taxes	23,699	24,401
Accrued interest	5,933	5,931
Lease market valuation liability	36,900	36,900
Other	18,060	23,145
	119,448	115,095
CAPITALIZATION:		
Common stockholder s equity-		
Common stock, $5 par value, authorized 60,000,000 shares, 29,402,054 shares outstanding	147,010	147,010
Other paid-in capital	178,157	178,182
Accumulated other comprehensive loss	(46,642)	(49,183)
Retained earnings	100,937	117,534
Total common stockholder s equity	379,462	393,543
Noncontrolling interest	2,593	2,589
Total equity	382,055	396,132
Long-term debt and other long-term obligations	600,524	600,493
	982,579	996,625
NONCURRENT LIABILITIES:		
Accumulated deferred income taxes	168,429	132,019
Accumulated deferred investment tax credits	5,715	5,930
Retirement benefits	51,764	71,486
Asset retirement obligations	29,737	28,762
Lease market valuation liability	180,850	199,300
Other	65,012	65,089
	501,507	502,586
COMMITMENTS, GUARANTEES AND CONTINGENCIES (Note 9)		
	$ 1,603,534	$ 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)

(In thousands)	Six Months Ended June 30 2011	2010
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net Income	$ 17,408	$ 14,725
Adjustments to reconcile net income to net cash from operating activities-		
Provision for depreciation	15,890	15,963
Deferral of regulatory assets, net	(18,532)	(10,299)
Deferred rents and lease market valuation liability	(43,851)	(42,264)
Deferred income taxes and investment tax credits, net	41,457	16,503
Accrued compensation and retirement benefits	1,085	2,600
Accrued regulatory obligations	(1,193)	(632)
Pension trust contribution	(45,000)	
Cash collateral from (to) suppliers, net	(14)	343
Increase (decrease) in operating assets-		
Receivables	(48,807)	52,754
Prepayments and other current assets	(9,758)	3,608
Increase (decrease) in operating liabilities-		
Accounts payable	3,661	(61,195)
Accrued taxes	(701)	(4,007)
Other	5,771	(8,960)
Net cash used for operating activities	(82,584)	(20,861)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Redemptions and Repayments-		
Long-term debt	(105)	(111)
Short-term borrowings, net		(225,975)
Common stock dividend payments	(34,000)	(130,000)
Other	(1,742)	(112)
Net cash used for financing activities	(35,847)	(356,198)
CASH FLOWS FROM INVESTING ACTIVITIES:		
Property additions	(17,386)	(20,237)
Leasehold improvement payments from associated companies		32,829
Loans to associated companies, net	(32,050)	(10,818)
Redemptions of lessor notes	21,739	20,485
Sales of investment securities held in trusts	28,401	106,814
Purchases of investment securities held in trusts	(30,050)	(107,978)
Other	(1,473)	(2,905)

Net cash provided from (used for) investing activities		(30,819)		18,190
Net change in cash and cash equivalents		(149,250)		(358,869)
Cash and cash equivalents at beginning of period		149,262		436,712
Cash and cash equivalents at end of period	$	12	$	77,843

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 STATEMENTS OF INCOME AND COMPREHENSIVE INCOME
(Unaudited)

	Three Months Ended June 30		Six Months Ended June 30	
(In thousands)	**2011**	**2010**	**2011**	**2010**
STATEMENTS OF INCOME				
REVENUES:				
Electric sales	$ 576,977	$ 709,606	$ 1,211,000	$ 1,400,998
Excise tax collections	11,120	11,012	23,607	23,364
Total revenues	588,097	720,618	1,234,607	1,424,362
EXPENSES:				
Purchased power	328,463	410,470	698,631	824,486
Other operating expenses	78,603	75,177	164,682	170,837
Provision for depreciation	26,773	27,093	52,087	55,064
Amortization of regulatory assets, net	40,046	81,326	121,633	150,774
General taxes	15,115	14,902	32,526	31,338
Total expenses	489,000	608,968	1,069,559	1,232,499
OPERATING INCOME	99,097	111,650	165,048	191,863
OTHER INCOME (EXPENSE):				
Miscellaneous income	3,554	1,649	5,464	3,482
Interest expense	(31,125)	(30,041)	(61,782)	(59,464)
Capitalized interest	618	156	1,045	289
Total other expense	(26,953)	(28,236)	(55,273)	(55,693)
INCOME BEFORE INCOME TAXES	72,144	83,414	109,775	136,170
INCOME TAXES	30,383	33,521	48,461	57,051
NET INCOME	$ 41,761	$ 49,893	$ 61,314	$ 79,119
STATEMENTS OF COMPREHENSIVE INCOME				
NET INCOME	$ 41,761	$ 49,893	$ 61,314	$ 79,119

OTHER COMPREHENSIVE INCOME:				
Pension and other postretirement benefits	4,290	4,135	8,511	20,063
Unrealized gain on derivative hedges	69	69	138	138
Other comprehensive income	4,359	4,204	8,649	20,201
Income tax expense related to other comprehensive income	1,612	1,441	3,202	7,999
Other comprehensive income, net of tax	2,747	2,763	5,447	12,202
COMPREHENSIVE INCOME	$ 44,508	$ 52,656	$ 66,761	$ 91,321

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

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

(In thousands)	June 30, 2011	December 31, 2010
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 42	$ 4
Receivables-		
Customers, net of allowance for uncollectible accounts of $3,306 in 2011 and $3,769 in 2010	259,313	323,044
Associated companies	66,069	53,780
Other	25,580	26,119
Notes receivable associated companies	16,288	177,228
Prepaid taxes	135,679	10,889
Other	15,421	12,654
	518,392	603,718
UTILITY PLANT:		
In service	4,589,369	4,562,781
Less Accumulated provision for depreciation	1,682,577	1,656,939
	2,906,792	2,905,842
Construction work in progress	112,573	63,535
	3,019,365	2,969,377
OTHER PROPERTY AND INVESTMENTS:		
Nuclear fuel disposal trust	212,419	207,561
Nuclear plant decommissioning trusts	190,422	181,851
Other	2,118	2,104
	404,959	391,516
DEFERRED CHARGES AND OTHER ASSETS:		
Goodwill	1,810,936	1,810,936
Regulatory assets	469,490	513,395
Other	34,028	27,938
	2,314,454	2,352,269
	$ 6,257,170	$ 6,316,880

LIABILITIES AND CAPITALIZATION

CURRENT LIABILITIES:		
Currently payable long-term debt	$ 33,315	$ 32,402
Short-term borrowings-		
Associated companies	360,917	
Other	50,000	
Accounts payable-		
Associated companies	56,544	28,571
Other	159,720	158,442
Accrued compensation and benefits	35,578	35,232
Customer deposits	23,684	23,385
Accrued taxes	1,346	2,509
Accrued interest	18,059	18,111
Other	13,487	22,263
	752,650	320,915
CAPITALIZATION:		
Common stockholder s equity-		
Common stock, $10 par value, authorized 16,000,000 shares- 13,628,447 shares outstanding	136,284	136,284
Other paid-in capital	2,008,847	2,508,874
Accumulated other comprehensive loss	(248,095)	(253,542)
Retained earnings	288,484	227,170
Total common stockholder s equity	2,185,520	2,618,786
Long-term debt and other long-term obligations	1,754,582	1,769,849
	3,940,102	4,388,635
NONCURRENT LIABILITIES:		
Accumulated deferred income taxes	761,844	715,527
Power purchase contract liability	239,943	233,492
Nuclear fuel disposal costs	196,868	196,768
Retirement benefits	71,711	182,364
Asset retirement obligations	111,831	108,297
Other	182,221	170,882
	1,564,418	1,607,330
COMMITMENTS, GUARANTEES AND CONTINGENCIES (Note 9)		
	$ 6,257,170	$ 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)	Six Months Ended June 30 2011	Six Months Ended June 30 2010
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net Income	$ 61,314	$ 79,119
Adjustments to reconcile net income to net cash from operating activities-		
Provision for depreciation	52,087	55,064
Amortization of regulatory assets, net	121,633	150,774
Deferred purchased power and other costs	(70,998)	(67,664)
Deferred income taxes and investment tax credits, net	51,222	(1,425)
Accrued compensation and retirement benefits	1,319	2,608
Cash collateral paid, net	(235)	(23,400)
Pension trust contribution	(105,000)	
Decrease (increase) in operating assets-		
Receivables	58,466	(46,788)
Prepaid taxes	(124,790)	(111,968)
Increase (decrease) in operating liabilities-		
Accounts payable	13,856	11,924
Accrued taxes	(1,167)	10,368
Other	612	(6,446)
Net cash provided from operating activities	58,319	52,166
CASH FLOWS FROM FINANCING ACTIVITIES:		
New Financing-		
Short-term borrowings, net	410,917	57,850
Redemptions and Repayments-		
Long-term debt	(14,671)	(13,830)
Common stock dividend payments		(90,000)
Equity payment to parent	(500,000)	
Other	(1,452)	
Net cash used for financing activities	(105,206)	(45,980)
CASH FLOWS FROM INVESTING ACTIVITIES:		
Property additions	(98,153)	(80,727)
Loans to associated companies, net	160,940	85,049
Sales of investment securities held in trusts	375,885	281,242
Purchases of investment securities held in trusts	(385,448)	(289,454)
Other	(6,299)	(2,224)
Net cash provided from (used for) investing activities	46,925	(6,114)

Net change in cash and cash equivalents		38		72
Cash and cash equivalents at beginning of period		4		27
Cash and cash equivalents at end of period	$	42	$	99

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 June 30		Six Months Ended June 30	
(In thousands)	2011	2010	2011	2010
REVENUES:				
Electric sales	$ 265,363	$ 422,030	$ 603,779	$ 873,590
Gross receipts tax collections	14,601	20,629	33,401	42,196
Total revenues	279,964	442,659	637,180	915,786
EXPENSES:				
Purchased power from affiliates	34,935	149,000	84,824	310,080
Purchased power from non-affiliates	100,836	85,276	253,879	177,204
Other operating expenses	50,075	90,151	97,307	192,134
Provision for depreciation	12,766	13,440	25,189	26,198
Amortization of regulatory assets, net	22,167	48,589	54,261	97,389
General taxes	17,152	19,894	39,302	41,634
Total expenses	237,931	406,350	554,762	844,639
OPERATING INCOME	42,033	36,309	82,418	71,147
OTHER INCOME (EXPENSE):				
Interest income	13	880	106	2,097
Miscellaneous income	915	1,381	1,885	3,554
Interest expense	(13,130)	(13,002)	(26,187)	(26,775)
Capitalized interest	228	159	375	285
Total other expense	(11,974)	(10,582)	(23,821)	(20,839)
INCOME BEFORE INCOME TAXES	30,059	25,727	58,597	50,308
INCOME TAXES	13,281	8,618	19,232	20,884
NET INCOME	$ 16,778	$ 17,109	$ 39,365	$ 29,424
STATEMENTS OF COMPREHENSIVE INCOME				
NET INCOME	$ 16,778	$ 17,109	$ 39,365	$ 29,424

OTHER COMPREHENSIVE INCOME				
Pension and other postretirement benefits	2,227	2,162	4,190	11,871
Unrealized gain on derivative hedges	84	84	168	168
Other comprehensive income	2,311	2,246	4,358	12,039
Income tax expense related to other comprehensive income	869	724	1,632	4,901
Other comprehensive income, net of tax	1,442	1,522	2,726	7,138
COMPREHENSIVE INCOME	$ 18,220	$ 18,631	$ 42,091	$ 36,562

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)	June 30, 2011	December 31, 2010
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 157	$ 243,220
Receivables-		
Customers, net of allowance for uncollectible accounts of $3,087 in 2011 and $3,868 in 2010	143,820	178,522
Associated companies	12,849	24,920
Other	16,437	13,007
Notes receivable from associated companies	10,432	11,028
Prepaid taxes	27,083	343
Other	1,443	2,289
	212,221	473,329
UTILITY PLANT:		
In service	2,266,437	2,247,853
Less Accumulated provision for depreciation	859,055	846,003
	1,407,382	1,401,850
Construction work in progress	42,604	23,663
	1,449,986	1,425,513
OTHER PROPERTY AND INVESTMENTS:		
Nuclear plant decommissioning trusts	301,188	289,328
Other	840	884
	302,028	290,212
DEFERRED CHARGES AND OTHER ASSETS:		
Goodwill	416,499	416,499
Regulatory assets	341,488	295,856
Power purchase contract asset	65,861	111,562
Other	54,587	31,699
	878,435	855,616
	$ 2,842,670	$ 3,044,670
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		

Currently payable long-term debt	$ 28,760	$ 28,760
Short-term borrowings-		
Associated companies	238,399	124,079
Other	50,000	
Accounts payable-		
Associated companies	24,377	33,942
Other	48,262	29,862
Accrued taxes	12,844	60,856
Accrued interest	16,011	16,114
Other	29,605	29,278
	448,258	322,891
CAPITALIZATION:		
Common stockholder s equity-		
Common stock, without par value, authorized 900,000 shares, 740,905 and 859,500 shares outstanding, respectively	842,023	1,197,076
Accumulated other comprehensive loss	(139,657)	(142,383)
Retained earnings	46,772	32,406
Total common stockholder s equity	749,138	1,087,099
Long-term debt and other long-term obligations	704,486	718,860
	1,453,624	1,805,959
NONCURRENT LIABILITIES:		
Accumulated deferred income taxes	494,716	473,009
Accumulated deferred investment tax credits	6,656	6,866
Nuclear fuel disposal costs	44,471	44,449
Asset retirement obligations	199,162	192,659
Retirement benefits	22,276	29,121
Power purchase contract liability	121,924	116,027
Other	51,583	53,689
	940,788	915,820
COMMITMENTS AND CONTINGENCIES (Note 9)		
	$ 2,842,670	$ 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)	Six Months Ended June 30 2011	Six Months Ended June 30 2010
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net Income	$ 39,365	$ 29,424
Adjustments to reconcile net income to net cash from operating activities-		
Provision for depreciation	25,189	26,198
Amortization of regulatory assets, net	54,261	97,389
Deferred costs recoverable as regulatory assets	(41,699)	(38,358)
Deferred income taxes and investment tax credits, net	11,972	(12,079)
Accrued compensation and retirement benefits	(510)	(1,573)
Cash collateral from suppliers, net	174	50
Pension trust contribution	(35,000)	
Decrease (increase) in operating assets-		
Receivables	46,240	(29,439)
Prepaid taxes	(26,740)	(31,246)
Increase (decrease) in operating liabilities-		
Accounts payable	5,148	733
Accrued taxes	(47,676)	9,519
Accrued interest	(103)	(1,277)
Other	10,903	7,553
Net cash provided from operating activities	41,524	56,894
CASH FLOWS FROM FINANCING ACTIVITIES:		
New Financing-		
Short-term borrowings, net	164,320	17,898
Redemptions and Repayments-		
Common stock	(150,000)	
Long-term debt	(14,784)	(100,000)
Common stock dividend payments	(80,000)	
Equity payment to parent	(150,000)	
Net cash used for financing activities	(230,464)	(82,102)
CASH FLOWS FROM INVESTING ACTIVITIES:		
Property additions	(46,647)	(54,405)
Sales of investment securities held in trusts	501,260	376,610
Purchases of investment securities held in trusts	(506,220)	(381,219)
Loans to associated companies, net	596	85,943
Other	(3,112)	(1,715)

Net cash provided from (used for) investing activities		(54,123)		25,214
Net change in cash and cash equivalents		(243,063)		6
Cash and cash equivalents at beginning of period		243,220		120
Cash and cash equivalents at end of period	$	157	$	126

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 June 30 2011	Three Months Ended June 30 2010	Six Months Ended June 30 2011	Six Months Ended June 30 2010
STATEMENTS OF INCOME				
REVENUES:				
Electric sales	$ 238,942	$ 350,335	$ 547,258	$ 736,271
Gross receipts tax collections	12,727	16,162	29,256	33,686
Total revenues	251,669	366,497	576,514	769,957
EXPENSES:				
Purchased power from affiliates	54,635	152,945	102,119	321,345
Purchased power from non-affiliates	64,459	86,829	205,895	178,252
Other operating expenses	44,570	67,070	85,898	139,464
Provision for depreciation	15,770	16,605	30,343	31,287
Amortization (deferral) of regulatory assets, net	12,608	(10,522)	25,615	(20,488)
General taxes	14,665	18,647	35,401	35,181
Total expenses	206,707	331,574	485,271	685,041
OPERATING INCOME	44,962	34,923	91,243	84,916
OTHER INCOME (EXPENSE):				
Miscellaneous income	644	1,310	669	2,923
Interest expense	(17,361)	(17,630)	(34,595)	(34,920)
Capitalized interest	41	183	63	323
Total other expense	(16,676)	(16,137)	(33,863)	(31,674)
INCOME BEFORE INCOME TAXES	28,286	18,786	57,380	53,242
INCOME TAXES	13,568	5,812	25,356	22,969
NET INCOME	$ 14,718	$ 12,974	$ 32,024	$ 30,273

STATEMENTS OF COMPREHENSIVE INCOME

NET INCOME	$	14,718	$	12,974	$	32,024	$	30,273
OTHER COMPREHENSIVE INCOME:								
Pension and other postretirement benefits		1,890		1,830		3,475		10,377
Unrealized gain on derivative hedges		17		16		33		32
Other comprehensive income		1,907		1,846		3,508		10,409
Income tax expense related to other comprehensive income		678		483		1,233		3,767
Other comprehensive income, net of tax		1,229		1,363		2,275		6,642
COMPREHENSIVE INCOME	$	15,947	$	14,337	$	34,299	$	36,915

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)	June 30, 2011	December 31, 2010
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 2	$ 5
Receivables-		
Customers, net of allowance for uncollectible accounts of $2,856 in 2011 and $3,369 in 2010	121,511	148,864
Associated companies	65,989	54,052
Other	11,420	11,314
Notes receivable from associated companies	13,498	14,404
Prepaid taxes	26,372	14,026
Other	1,423	1,592
	240,215	244,257
UTILITY PLANT:		
In service	2,552,303	2,532,629
Less Accumulated provision for depreciation	947,315	935,259
	1,604,988	1,597,370
Construction work in progress	62,592	30,505
	1,667,580	1,627,875
OTHER PROPERTY AND INVESTMENTS:		
Nuclear plant decommissioning trusts	162,154	152,928
Non-utility generation trusts	126,786	80,244
Other	292	297
	289,232	233,469
DEFERRED CHARGES AND OTHER ASSETS:		
Goodwill	768,628	768,628
Regulatory assets	222,804	163,407
Power purchase contract asset	4,000	5,746
Other	15,272	19,287
	1,010,704	957,068
	$ 3,207,731	$ 3,062,669

LIABILITIES AND CAPITALIZATION

CURRENT LIABILITIES:		
Currently payable long-term debt	$ 45,000	$ 45,000
Short-term borrowings-		
Associated companies	159,902	101,338
Accounts payable-		
Associated companies	77,121	35,626
Other	29,217	41,420
Accrued taxes	3,397	5,075
Accrued interest	17,454	17,378
Other	23,280	22,541
	355,371	268,378
CAPITALIZATION:		
Common stockholder s equity-		
Common stock, $20 par value, authorized 5,400,000 shares- 4,427,577 shares outstanding	88,552	88,552
Other paid-in capital	913,486	913,519
Accumulated other comprehensive loss	(161,251)	(163,526)
Retained earnings	23,017	60,993
Total common stockholder s equity	863,804	899,538
Long-term debt and other long-term obligations	1,072,417	1,072,262
	1,936,221	1,971,800
NONCURRENT LIABILITIES:		
Accumulated deferred income taxes	415,899	371,877
Retirement benefits	188,407	187,621
Power purchase contract liability	160,130	116,972
Asset retirement obligations	101,441	98,132
Other	50,262	47,889
	916,139	822,491
COMMITMENTS, GUARANTEES AND CONTINGENCIES (Note 9)		
	$ 3,207,731	$ 3,062,669

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

PENNSYLVANIA ELECTRIC COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

(In thousands)	Six Months Ended June 30 2011	Six Months Ended June 30 2010
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net Income	$ 32,024	$ 30,273
Adjustments to reconcile net income to net cash from operating activities-		
Provision for depreciation	30,343	31,287
Amortization (deferral) of regulatory assets, net	25,615	(20,488)
Deferred costs recoverable as regulatory assets	(38,291)	(38,955)
Deferred income taxes and investment tax credits, net	46,687	42,943
Accrued compensation and retirement benefits	4,733	4,216
Cash collateral paid, net	(1,276)	(3,613)
Decrease (increase) in operating assets-		
Receivables	19,561	3,266
Prepaid taxes	(12,346)	(37,504)
Increase (decrease) in operating liabilities-		
Accounts payable	23,449	(4,603)
Accrued taxes	(12,373)	(1,339)
Other	13,153	10,227
Net cash provided from operating activities	131,279	15,710
CASH FLOWS FROM FINANCING ACTIVITIES:		
New Financing-		
Long-term debt	25,000	
Short-term borrowings, net	58,564	25,313
Redemptions and Repayments-		
Long-term debt	(25,000)	
Common stock dividend payments	(70,000)	
Other	(1,353)	5
Net cash provided from (used for) financing activities	(12,789)	25,318
CASH FLOWS FROM INVESTING ACTIVITIES:		
Property additions	(64,177)	(58,293)
Loans to associated companies, net	906	498
Sales of investment securities held in trusts	265,223	133,934
Purchases of investment securities held in trusts	(314,738)	(113,067)
Other	(5,707)	(4,104)
Net cash used for investing activities	(118,493)	(41,032)

Net change in cash and cash equivalents		(3)		(4)
Cash and cash equivalents at beginning of period		5		14
Cash and cash equivalents at end of period	$	2	$	10

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

FIRSTENERGY CORP. AND SUBSIDIARIES
COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

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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), FES and its subsidiaries FGCO and NGC, and FESC. AE merged with a subsidiary of FirstEnergy on February 25, 2011, with AE continuing 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 related regulations, orders, policies and practices prescribed by the SEC, FERC, and, as applicable, the PUCO, the PPUC, the MDPSC, the NYPSC, the WVPSC and the NJBPU. These unaudited interim financial statements and notes were prepared in accordance with GAAP for interim financial information. Accordingly, they do not include all of the information and footnotes required by GAAP for complete annual financial statements. 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.

These unaudited interim financial 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. 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 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

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The 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 accumulated deferred income taxes. The preliminary allocation of the purchase price is as follows:

(In millions)		
Current assets	$	1,494
Property, plant and equipment		9,656
Investments		138
Goodwill		881
Other noncurrent assets		1,347
Current liabilities		(716)
Noncurrent liabilities		(3,452)
Long-term debt and other long-term obligations		(4,994)
	$	4,354

The allocation of purchase price in the table above reflects a refinement made during the quarter ended June 30, 2011 in the determination of the fair values of income tax benefits, certain coal contracts and an adverse purchase power contract. This resulted in an increase in noncurrent assets of approximately $85 million and decreases in current assets and goodwill of $15 million and $71 million, respectively. The impact of the refinements on the amortization of purchase accounting adjustments recorded during the quarter ended March 31, 2011 was not significant. Further modifications to the purchase price allocation may occur as a result of continuing review of the assets acquired and liabilities assumed.

The estimated fair values of the assets acquired and liabilities assumed have been determined based on the accounting guidance for fair value measurements under GAAP, which defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date.

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 $881 million has been assigned 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 as of December 31, 2010	$ 5,551	$ 24	$	$	$ 5,575
Merger with Allegheny		881			881
Balance as of June 30, 2011	$ 5,551	$ 905	$	$	$ 6,456

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 contracts	$ 189	10 years
NUG contracts	124	25 years
Coal supply contracts	516	8 years
	829	
Below market contracts:		
NUG contracts	143	13 years
Coal supply contracts	83	7 years
Transportation contract	35	8 years
	261	
Net intangible assets	**$** 568	

The fair value measurements of intangible assets and liabilities were 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 adjustment for these contracts is being amortized based on expected deliveries under each contract.

As of June 30, 2011, intangible assets on FirstEnergy s Consolidated Balance Sheet, including those recorded in connection with the merger, include the following:

(In millions)	Intangible Assets
Purchase contract assets	
NUG	$ 198
OVEC	54
	252
Intangible assets	

Coal contracts		487
FES customer intangible assets		129
Energy contracts		105
		721
Total intangible assets	$	973

Acquired land easements and software with a fair value of $169 million are included in Property, plant and equipment on FirstEnergy s Consolidated Balance Sheet as of June 30, 2011.

In connection with the merger, FirstEnergy recorded merger transaction costs of approximately $7 million ($5 million net of tax) and $7 million ($5 million net of tax) during the three months ended June 30, 2011 and 2010, respectively and approximately $89 million ($72 million net of tax) and $21 million ($15 million net of tax) during the first six months of 2011 and 2010, respectively. These costs are included in Other operating expenses in the Consolidated Statements of Income. Merger transaction costs recognized in the first six months of 2011 include $56 million ($47 net of tax) of change in control and other benefit payments to AE executives.

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FirstEnergy also recorded approximately $10 million ($6 million net of tax) and $85 million ($66 million net of tax) in merger integration costs during the three and six months ended June 30 2011, respectively, 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 that 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) in the first quarter of 2011.

Revenues and earnings of Allegheny included in FirstEnergy s Consolidated Statement of Income for the periods subsequent to the February 25, 2011 merger date are as follows:

(In millions, except per share amounts)		April 1 June 30, 2011		February 26 June 30, 2011
Total revenues	$	1,181	$	1,618
Earnings available to FirstEnergy Corp.(1)		63		17
Basic Earnings Per Share	$	0.15	$	0.04
Diluted Earnings Per Share	$	0.15	$	0.04

(1) Includes Allegheny s after-tax merger costs of $4 million and $56 million, respectively.

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. Combined pre-tax transaction costs incurred were approximately $7 million and $11 million in the three months ended June 30, 2011 and 2010, respectively, and approximately $90 million and $39 million in the six months ended June 30, 2011 and 2010, respectively. In addition, during the six months ended June 30, 2011, $85 million of pre-tax merger integration costs and $32 million of charges from merger settlements approved by regulatory agencies were recognized. Charges resulting from merger settlements are not expected to be material in future periods.

The unaudited pro forma financial information has been presented below for illustrative purposes only and is not necessarily indicative of results of operations that would have been achieved or the future consolidated results of operations of the combined company.

(Pro forma amounts in millions, except per share amounts)	Three Months Ended June 30				Six Months Ended June 30			
		2011		2010		2011		2010
Revenues	$	4,062	$	4,401	$	8,848	$	9,086
Earnings available to FirstEnergy	$	186	$	389	$	323	$	644
Basic Earnings Per Share	$	0.44	$	0.93	$	0.77	$	1.54
Diluted Earnings Per Share	$	0.44	$	0.93	$	0.77	$	1.53

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 June 30 2011	Three Months Ended June 30 2010	Six Months Ended June 30 2011	Six Months Ended June 30 2010
	(In millions, except per share amounts)			
Earnings available to FirstEnergy Corp.	$ 181	$ 265	$ 231	$ 420
Weighted average number of basic shares outstanding[1]	418	304	380	304
Assumed exercise of dilutive stock options and awards	2	1	2	1
Weighted average number of diluted shares outstanding[1]	420	305	382	305
Basic earnings per share of common stock	$ 0.43	$ 0.87	$ 0.61	$ 1.38
Diluted earnings per share of common stock	$ 0.43	$ 0.87	$ 0.61	$ 1.37

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

4. FAIR VALUE MEASUREMENTS

(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 June 30, 2011 and December 31 2010:

	June 30, 2011 Carrying Value	June 30, 2011 Fair Value	December 31, 2010 Carrying Value	December 31, 2010 Fair Value
	(In millions)			
FirstEnergy[1]	$ 18,371	$ 19,436	$ 13,928	$ 14,845
FES	4,056	4,310	4,279	4,403
OE	1,158	1,367	1,159	1,321
CEI	1,831	2,083	1,853	2,035
TE	600	690	600	653
JCP&L	1,795	2,008	1,810	1,962
Met-Ed	729	828	742	821
Penelec	1,120	1,231	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 June 30, 2011 of $4,530 million and $4,127 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.

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 while unrealized losses are recorded to 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 the 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 trusts 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 funds custodian or managers and their parents or subsidiaries.

Available-For-Sale Securities

FES and the Utilities hold debt and equity securities within their NDT, 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 NDT, nuclear fuel disposal trusts and NUG trusts as of June 30, 2011 and December 31, 2010:

	June 30, 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	$ 2,015	$ 48	$	$ 2,063	$ 1,699	$ 31	$	$ 1,730
FES	1,023	26		1,049	980	13		993
OE	128	3		131	123	1		124
TE	52	1		53	42			42
JCP&L	353	9		362	281	9		290
Met-Ed	249	5		254	127	4		131
Penelec	210	4		214	145	4		149
Equity securities								
FirstEnergy	$ 187	$ 11	$	$ 198	$ 268	$ 69	$	$ 337
FES	90	6		96				
TE	24	2		26				
JCP&L	21	1		22	80	17		97
Met-Ed	32	1		33	125	35		160
Penelec	20	1		21	63	16		79

(1) Excludes cash investments, receivables, payables, deferred taxes and accrued income: FirstEnergy $130 million; FES $39 million; OE $3 million; JCP&L $19 million; Met-Ed $14 million and Penelec $55 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 to earnings and interest and dividend income for the three months and six months ended June 30, 2011 and 2010 were as follows:

Three Months Ended June 30,

2011	Sales Proceeds	Realized Gains	Realized Losses	Interest and Dividend Income
		(In millions)		
FirstEnergy	$ 734	$ 22	$ (16)	$ 28
FES	297	10	(7)	17
OE	12			1
TE	15	1	(1)	1
JCP&L	159	4	(2)	4
Met-Ed	165	4	(3)	3
Penelec	86	3	(3)	2

2010	Sales Proceeds	Realized Gains	Realized Losses	Interest and Dividend Income
		(In millions)		
FirstEnergy	$ 1,183	$ 46	$ (36)	$ 16
FES	685	41	(35)	9
OE	57	2		
TE	76	2		
JCP&L	91			3
Met-Ed	233	1	(1)	2
Penelec	41			2

Six Months Ended June 30,

2011	Sales Proceeds	Realized Gains	Realized Losses	Interest and Dividend Income
		(In millions)		
FirstEnergy	$ 1,703	$ 122	$ (45)	$ 52
FES	513	22	(23)	32
OE	20			2
TE	28	1	(2)	1
JCP&L	376	26	(6)	8
Met-Ed	501	48	(7)	5
Penelec	265	25	(7)	4

2010	Sales Proceeds	Realized Gains	Realized Losses	Interest and Dividend Income
		(In millions)		
FirstEnergy	$ 1,915	$ 83	$ (86)	$ 37

FES	957	54	(58)	22
OE	60	2		1
TE	107	3		1
JCP&L	281	9	(9)	7
Met-Ed	377	9	(12)	3
Penelec	134	6	(7)	3

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 June 30, 2011 and December 31, 2010:

	June 30, 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	$ 414	$ 84	$	498	$ 476	$ 91	$	$ 567
OE	178	45		223	190	51		241
CEI	287	39		326	340	41		381

Investments in emission allowances, employee benefits and cost and equity method investments totaling $345 million as of June 30, 2011 and $259 million as of December 31, 2010, are not required to be disclosed and are excluded from the amounts reported above.

Notes Receivable

The table below provides the approximate fair value and related carrying amounts of notes receivable as of June 30, 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.

	June 30, 2011		December 31, 2010	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	(In millions)			
Notes Receivable				
FirstEnergy	$ 6	$ 7	$ 7	$ 8
TE	82	94	104	118

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(C) RECURRING FAIR VALUE MEASUREMENTS

Authoritative accounting guidance establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. This hierarchy gives the highest priority to Level 1 measurements and the lowest priority to Level 3 measurements.

The three levels of the fair value hierarchy are as follows:

Level 1	Quoted prices for identical instruments in active markets.
Level 2	Quoted prices for similar instruments in active markets;
	quoted prices for identical or similar instruments in markets that are not active; and
	model-derived valuations for which all significant inputs are observable market data.
Level 3	Valuation inputs are unobservable and significant to the fair value measurement.

The following tables set forth financial assets and liabilities measured at fair value on a recurring basis by level within the fair value hierarchy. There were no significant transfers between levels during the three months and six months ended June 30, 2011.

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FirstEnergy Corp.

The following tables summarize assets and liabilities recorded on FirstEnergy s Consolidated Balance Sheets at fair value as of June 30, 2011 and December 31, 2010:

June 30, 2011	**Level 1**	**Level 2**	**Level 3**	**Total**
		(In millions)		
Assets				
Corporate debt securities	$	$ 868	$	$ 868
Derivative assets commodity contracts		312		312
Derivative assets FTRs			13	13
Derivative assets interest rate swaps		4		4
Derivative assets NUG contracts[1]			75	75
Equity securities[2]	198			198
Foreign government debt securities		206		206
U.S. government debt securities		673		673
U.S. state debt securities		306		306
Other[4]		146		146
Total assets	$ 198	$ 2,515	$ 88	$ 2,801
Liabilities				
Derivative liabilities commodity contracts	$	$ (362)	$	$ (362)
Derivative liabilities FTRs			(7)	(7)
Derivative liabilities interest rate swaps		(5)		(5)
Derivative liabilities NUG contracts[1]			(522)	(522)
Total liabilities	$	$ (367)	$ (529)	$ (896)
Net assets (liabilities)[3]	$ 198	$ 2,148	$ (441)	$ 1,905

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 generally subject to regulatory accounting and do not materially 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 $6 million and $(7) million as of June 30, 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 during the periods ending June 30, 2011 and December 31, 2010:

	Derivative Asset[1]	Derivative Liability[1] *(In millions)*	Net[1]
January 1, 2011 Balance	$ 122	$ (466)	$ (344)
Realized gain (loss)			
Unrealized gain (loss)	(40)	(203)	(243)
Purchases	13	(3)	10
Issuances			
Sales			
Settlements	(6)	154	148
Transfers into Level 3		(12)	(12)
June 30, 2011 Balance	$ 89	$ (530)	$ (441)
January 1, 2010 Balance	$ 200	$ (643)	$ (443)
Realized gain (loss)			
Unrealized gain (loss)	(71)	(110)	(181)
Purchases			
Issuances			
Sales			
Settlements	(7)	287	280
Transfers into Level 3			
December 31, 2010 Balance	$ 122	$ (466)	$ (344)

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

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FirstEnergy Solutions Corp.

The following tables summarize assets and liabilities recorded on FES Consolidated Balance Sheets at fair value as of June 30, 2011 and December 31, 2010:

June 30, 2011	**Level 1**	**Level 2**	**Level 3**	**Total**
		(In millions)		
Assets				
Corporate debt securities	$	$ 562	$	$ 562
Derivative assets commodity contracts		283		283
Derivative assets FTRs			2	2
Equity securities[3]	96			96
Foreign government debt securities		160		160
U.S. government debt securities		316		316
U.S. state debt securities		7		7
Other[2]		42		42
Total assets	$ 96	$ 1,370	$ 2	$ 1,468
Liabilities				
Derivative liabilities commodity contracts	$	$ (327)	$	$ (327)
Total liabilities	$	$ (327)	$	$ (327)
Net assets (liabilities)[1]	$ 96	$ 1,043	$ 2	$ 1,141

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 $7 million as of 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.

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 during the period ending June 30, 2011:

	Derivative Asset FTRs	Derivative Liability FTRs	Net FTRs
		(In millions)	
January 1, 2011 Balance	$	$	$
Realized gain (loss)			
Unrealized gain (loss)	1		1
Purchases	2		2
Issuances			
Sales			
Settlements	(1)		(1)
Transfers in (out) of Level 3			
June 30, 2011 Balance	$ 2	$	$ 2

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Ohio Edison Company

The following tables summarize assets and liabilities recorded on OE s Consolidated Balance Sheets at fair value as of June 30, 2011 and December 31, 2010:

June 30, 2011	Level 1		Level 2		Level 3		Total	
			(In millions)					
Assets								
U.S. government debt securities	$		$	131	$		$	131
Other				2				2
Total assets[1]	$		$	133	$		$	133

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 $2 million and $1 million as of June 30, 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.

The Toledo Edison Company

The following tables summarize assets and liabilities recorded on TE s Consolidated Balance Sheets at fair value as of June 30, 2011 and December 31, 2010:

June 30, 2011	Level 1		Level 2		Level 3		Total	
			(In millions)					
Assets								
Corporate debt securities	$		$	16	$		$	16
Equity securities[3]		26						26
U.S. government debt securities				33				33
U.S. state debt securities				1				1
Other[2]				3				3
Total assets[1]	$	26	$	53	$		$	79

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 June 30, 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.

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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 June 30, 2011 and December 31, 2010:

June 30, 2011	**Level 1**	**Level 2**	**Level 3**	**Total**
		(In millions)		
Assets				
Corporate debt securities	$	$ 81	$	$ 81
Derivative assets NUG contracts[1]			5	5
Equity securities[2]	21			21
Foreign government debt securities		13		13
U.S. government debt securities		54		54
U.S. state debt securities		215		215
Other		14		14
Total assets	$ 21	$ 377	$ 5	$ 403
Liabilities				
Derivative liabilities NUG contracts[1]	$	$	$ (240)	$ (240)
Total liabilities	$	$	$ (240)	$ (240)
Net assets (liabilities)[3]	$ 21	$ 377	$ (235)	$ 163

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 $5 million and $(3) million as of June 30, 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 JCP&L and classified as Level 3 in the fair value hierarchy during the periods ending June 30, 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)	(1)	(71)	(72)
Purchases			
Issuances			
Sales			
Settlements		64	64
Transfers in (out) of Level 3			
June 30, 2011 Balance	$ 5	$ (240)	$ (235)
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.

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Metropolitan Edison Company

The following tables summarize assets and liabilities recorded on Met-Ed s Consolidated Balance Sheets at fair value as of June 30, 2011 and December 31, 2010:

June 30, 2011	**Level 1**	**Level 2**	**Level 3**	**Total**
		(In millions)		
Assets				
Corporate debt securities	$	$ 138	$	$ 138
Derivative assets NUG contracts(1)			66	66
Equity securities(2)	33			33
Foreign government debt securities		20		20
U.S. government debt securities		87		87
U.S. state debt securities		2		2
Other		22		22
Total assets	$ 33	$ 269	$ 66	$ 368
Liabilities				
Derivative liabilities NUG contracts(1)	$	$	$ (122)	$ (122)
Total liabilities	$	$	$ (122)	$ (122)
Net assets (liabilities)(3)	$ 33	$ 269	$ (56)	$ 246

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 June 30, 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 during the periods ending June 30, 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)	(42)	(36)	(78)
Purchases			
Issuances			
Sales			
Settlements	(4)	30	26
Transfers in (out) of Level 3			
June 30, 2011 Balance	$ 66	$ (122)	$ (56)
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.

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Pennsylvania Electric Company

The following tables summarize assets and liabilities recorded on Penelec s Consolidated Balance Sheets at fair value as of June 30, 2011 and December 31, 2010:

June 30, 2011	**Level 1**	**Level 2**	**Level 3**	**Total**
		(In millions)		
Assets				
Corporate debt securities	$	$ 69	$	$ 69
Derivative assets NUG contracts[1]			4	4
Equity securities[2]	20			20
Foreign government debt securities		12		12
U.S. government debt securities		52		52
U.S. state debt securities		81		81
Other		53		53
Total assets	$ 20	$ 267	$ 4	$ 291
Liabilities				
Derivative liabilities NUG contracts[1]	$	$	$ (160)	$ (160)
Total liabilities	$	$	$ (160)	$ (160)
Net assets (liabilities)[3]	$ 20	$ 267	$ (156)	$ 131

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 $1 million and $(3) million as of June 30, 2011 and December 31, 2010, respectively, of receivables, payables 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 and commodity contracts held by Penelec and classified as Level 3 in the fair value hierarchy during the periods ended June 30, 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)		(88)	(88)
Purchases			
Issuances			
Sales			
Settlements		45	45
Transfers in (out) of Level 3			
June 30, 2011 Balance	$ 4	$ (160)	$ (156)
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 s Risk Policy Committee, comprised of senior management, 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 in AOCL. Changes in the fair value of derivative instruments that are not designated as cash flow hedge instruments are recorded in net income on a mark-to-market basis. FirstEnergy 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 gains included in AOCL associated with dedesignated cash flow hedges totaled $8 million as of June 30, 2011. Since the forecasted transactions remain probable of occurring, these amounts will be amortized into earnings over the life of the hedging instruments. Reclassifications from AOCL into other operating expenses totaled $14 million and $19 million during the three months and six months ended June 30, 2011, respectively. Approximately $3 million is expected to be amortized to 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 June 30, 2011, no forward starting swap agreements were outstanding. Total unamortized losses included in AOCL associated with prior interest rate cash flow hedges totaled $84 million ($55 million net of tax) as of June 30, 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 during the three months ended June 30, 2011 and 2010 and $6 million during the six months ended June 30, 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 June 30, 2011, no fixed-for-floating interest rate swap agreements were outstanding.

Unamortized gains included in long-term debt associated with prior fixed-for-floating interest rate swap agreements totaled $113 million ($73 million net of tax) as of June 30, 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 $6 million and $2 million during the three months ended June 30, 2011 and 2010, respectively and $11 million and $3 million during the six months ended June 30, 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 is 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 June 30, 2011, FirstEnergy s net liability position under commodity derivative contracts was $45 million, which primarily related to FES positions. Under these commodity derivative contracts, FES posted $81 million and Allegheny posted $2 million in collateral. Certain commodity derivative contracts include credit risk related contingent features that would require FES to post $49 million of additional collateral if the credit rating for its debt were to fall below investment grade.

Based on derivative contracts held as of June 30, 2011, an adverse 10% change in commodity prices would decrease net income by approximately $31 million ($20 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. FirstEnergy acquires the majority of its FTRs in an annual auction through a self-scheduling process involving the use of ARRs allocated to members of an RTO that have load serving obligations and through the direct allocation of FTRs from the PJM RTO. The PJM RTO has a rule that allows directly allocated FTRs to be granted to LSEs in zones that have newly entered PJM. For the first two planning years, PJM permits the LSEs to request a direct allocation of FTRs in these new zones at no cost as opposed to receiving ARRs. The directly allocated FTRs differ from traditional FTRs in that the ownership of all or part of the FTRs may shift to another LSE if customers choose to shop with the other LSE.

The future obligations for the FTRs acquired at auction are reflected on the Consolidated Balance Sheets and have not been designated as cash flow hedge instruments. FirstEnergy initially records these FTRs at the 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. Directly allocated FTRs are accounted for under the accrual method of accounting, and their effects are included in earnings at the time of contract performance.

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The following tables summarize the fair value of derivative instruments in FirstEnergy s Consolidated Balance Sheets:
Derivatives not designated as hedging instruments as of June 30, 2011:

Derivative Assets

	Fair Value	
	June 30, 2011	**December 31, 2010**
	(In millions)	
Power Contracts		
Current Assets	$ 210	$ 96
Noncurrent Assets	102	40
FTRs		
Current Assets	13	
Noncurrent Assets		
NUGs		
Current Assets	4	3
Noncurrent Assets	71	119
Interest Rate Swaps		
Current Assets	4	
Noncurrent Assets		
Other		
Current Assets		10
Noncurrent Assets		
Total Derivatives	$ 404	$ 268

Derivative Liabilities

	Fair Value	
	June 30, 2011	**December 31, 2010**
	(In millions)	
Power Contracts		
Current Liabilities	$ 274	$ 209
Noncurrent Liabilities	88	38
FTRs		
Current Liabilities	7	
Noncurrent Liabilities		
NUGs		
Current Liabilities	317	229
Noncurrent Liabilities	205	238
Interest Rate Swaps		
Current Liabilities	5	
Noncurrent Liabilities		
Other		

Current Liabilities				
Noncurrent Liabilities				
Total Derivatives	$	896	$	714

The following table summarizes the volumes associated with FirstEnergy s outstanding derivative transactions as of June 30, 2011:

	Purchases	**Sales**	**Net**	**Units**
		(In thousands)		
Power Contracts	45,573	(59,549)	(13,976)	MWH
FTRs	53,656		53,656	MWH
Interest Rate Swaps	200,000	(200,000)		notional dollars
NUGs	26,903		26,903	MWH

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The effect of derivative instruments on the Consolidated Statements of Income during the three months and six months ended June 30, 2011 and 2010, are summarized in the following tables:

	Three Months Ended June 30,				
	Power Contracts	FTRs	Interest Rate Swaps	Other	Total
			(In millions)		
Derivatives in a Hedging Relationship					
2011					
Gain (Loss) Recognized in AOCL (Effective Portion)	$ 14	$	$	$	$ 14
Effective Gain (Loss) Reclassified to: [1]					
Purchase Power Expense					
Revenues					
2010					
Gain (Loss) Recognized in AOCL (Effective Portion)	$	$	$	$ 3	$ 3
Effective Gain (Loss) Reclassified to:[1]					
Purchase Power Expense	(3)				(3)
Revenues	(5)				(5)
Fuel Expense				(4)	(4)
Derivatives Not in a Hedging Relationship					
2011					
Unrealized Gain (Loss) Recognized in:					
Purchase Power Expense	$ 33	$	$	$	$ 33
Revenues	(4)				(4)
Other Operating Expense	(34)	13			(21)
Realized Gain (Loss) Reclassified to:					
Purchase Power Expense	1				1
Revenues	(39)	18			(21)
Other Operating Expense		(59)			(59)
2010					
Unrealized Gain (Loss) Recognized in:					
Purchase Power Expense	$ 66	$	$	$	$ 66
Realized Gain (Loss) Reclassified to:					
Purchase Power Expense	(26)				(26)

Derivatives Not in a Hedging Relationship with Regulatory Offset[2]	Three Months Ended June 30,		
	NUGs	Other	Total
		(In millions)	
2011			
Unrealized Gain (Loss) to Derivative Instrument:	$ (147)	$ 2	$ (145)
Unrealized Gain (Loss) to Regulatory Assets:	147	(2)	145

Realized Gain (Loss) to Derivative Instrument:		62		62
Realized Gain (Loss) to Regulatory Assets:		(62)		(62)
2010				
Unrealized Gain (Loss) to Derivative Instrument:	$	(35)	$	(35)
Unrealized Gain (Loss) to Regulatory Assets:		35		35
Realized Gain (Loss) to Derivative Instrument:		68		68
Realized Gain (Loss) to Regulatory Assets:		(68)		(68)

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	Six Months Ended June 30,				
	Power Contracts	FTRs	Interest Rate Swaps	Other	Total
			(In millions)		
Derivatives in a Hedging Relationship					
2011					
Gain (Loss) Recognized in AOCL (Effective Portion)	$ 5	$	$	$	$ 5
Effective Gain (Loss) Reclassified to: [1]					
Purchase Power Expense	16				16
Revenues	(12)				(12)
2010					
Gain (Loss) Recognized in AOCL (Effective Portion)	$ (2)	$	$	$ 6	$ 4
Effective Gain (Loss) Reclassified to:[1]					
Purchase Power Expense	(7)				(7)
Revenues	(5)				(5)
Fuel Expense				(8)	(8)
Derivatives Not in a Hedging Relationship					
2011					
Unrealized Gain (Loss) Recognized in:					
Purchase Power Expense	$ 61	$	$	$	$ 61
Revenues	(3)				(3)
Other Operating Expense	(54)	13	1		(40)
Realized Gain (Loss) Reclassified to:					
Purchase Power Expense	(36)				(36)
Revenues	(29)	26			(3)
Other Operating Expense		(87)			(87)
2010					
Unrealized Gain (Loss) Recognized in:					
Purchase Power Expense	$ 39	$	$	$	$ 39
Realized Gain (Loss) Reclassified to:					
Purchase Power Expense	(49)				(49)

Derivatives Not in a Hedging Relationship with Regulatory Offset[2]	Six Months Ended June 30,		
	NUGs	Other	Total
		(In millions)	
2011			
Unrealized Gain (Loss) to Derivative Instrument:	$ (236)	$ 2	$ (234)
Unrealized Gain (Loss) to Regulatory Assets:	236	(2)	234
Realized Gain (Loss) to Derivative Instrument:	134	(10)	124
Realized Gain (Loss) to Regulatory Assets:	(134)	10	(124)

2010			
Unrealized Gain (Loss) to Derivative Instrument:	$ (259)		$ (259)
Unrealized Gain (Loss) to Regulatory Assets:	259		259
Realized Gain (Loss) to Derivative Instrument:	146	(9)	137
Realized Gain (Loss) to Regulatory Assets:	(146)	9	(137)

(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 recovery from (or refund to) customers during the three months and six months ended June 30, 2011 and 2010:

Derivatives Not in a Hedging Relationship with Regulatory Offset[1]	Three Months Ended June 30, NUGs	Other	Total
		(In millions)	
Outstanding net asset (liability) as of April 1, 2011	$ (362)	$	$ (362)
Additions/Change in value of existing contracts	(147)	2	(145)
Settled contracts	62		62
Outstanding net asset (liability) as of June 30, 2011	$ (447)	$ 2	$ (445)
Outstanding net asset (liability) as of April 1, 2010	$ (590)	$ 10	$ (580)
Additions/Change in value of existing contracts	(35)		(35)
Settled contracts	68		68
Outstanding net asset (liability) as of June 30, 2010	$ (557)	$ 10	$ (547)

Derivatives Not in a Hedging Relationship with Regulatory Offset[1]	Six Months Ended June 30, NUGs	Other	Total
		(In millions)	
Outstanding net asset (liability) as of January 1, 2011	$ (345)	$ 10	$ (335)
Additions/Change in value of existing contracts	(236)	2	(234)
Settled contracts	134	(10)	124
Outstanding net asset (liability) as of June 30, 2011	$ (447)	$ 2	$ (445)
Outstanding net asset (liability) as of January 1, 2010	$ (444)	$ 19	$ (425)
Additions/Change in value of existing contracts	(259)		(259)
Settled contracts	146	(9)	137
Outstanding net asset (liability) as of June 30, 2010	$ (557)	$ 10	$ (547)

(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 three months and six months ended June 30, 2011, FirstEnergy made pre-tax contributions to its qualified pension plans of $105 million and $262 million, respectively. FirstEnergy intends to make additional contributions of $116 million and $2 million to its qualified pension plans and postretirement benefit plans, respectively, in the last two quarters of 2011.

As result of the merger with Allegheny, FirstEnergy assumed certain pension and OPEB plans. 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. 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 as of that date were $1,341 million and $272 million, respectively. The expected returns on plan assets used to calculate net periodic costs for periods in 2011 subsequent to the date of the merger are 8.25% for Allegheny s qualified pension plan and 5.00% for Allegheny s postretirement benefit plans other than pensions.
The components of the consolidated net periodic cost for pension and OPEB benefits (including amounts capitalized) were as follows:

Pension Benefit Cost (Credit)	**Three Months Ended June 30** 2011	2010	**Six Months Ended June 30** 2011	2010
		(In millions)		
Service cost	$ 34	$ 25	$ 62	$ 49
Interest cost	97	79	181	157
Expected return on plan assets	(115)	(90)	(216)	(181)
Amortization of prior service cost	4	3	7	6
Recognized net actuarial loss	48	47	97	94
Curtailments[(1)]			(2)	
Special termination benefits[(1)]			9	
Net periodic cost	**$ 68**	**$ 64**	**$ 138**	**$ 125**

(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.

Other Postretirement Benefit Cost (Credit)	**Three Months Ended June 30** 2011	2010	**Six Months Ended June 30** 2011	2010
		(In millions)		
Service cost	$ 3	$ 3	$ 7	$ 5
Interest cost	12	11	23	22
Expected return on plan assets	(10)	(9)	(20)	(18)
Amortization of prior service cost	(52)	(48)	(100)	(96)
Recognized net actuarial loss	14	15	28	30
Net periodic cost (credit)	**$ (33)**	**$ (28)**	**$ (62)**	**$ (57)**

Pension and OPEB obligations are allocated to FirstEnergy s subsidiaries employing the plan participants. The net periodic pension costs and net periodic OPEB (including amounts capitalized) recognized by FirstEnergy s subsidiaries were as follows:

Pension Benefit Cost	**Three Months Ended June 30** 2011	2010	**Six Months Ended June 30** 2011	2010
		(In millions)		

FES	$ 22	$ 22	$ 43	$ 44
OE	5	6	11	11
CEI	5	5	10	11
TE	2	2	3	4
JCP&L	5	6	11	12
Met-Ed	3	3	5	5
Penelec	4	5	9	9
Other FirstEnergy Subsidiaries	22	15	46	29
	$ 68	**$ 64**	**$ 138**	**$ 125**

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Other Postretirement Benefit Credit	Three Months Ended June 30 2011	Three Months Ended June 30 2010	Six Months Ended June 30 2011	Six Months Ended June 30 2010
	(In millions)			
FES	$ (8)	$ (7)	$ (14)	$ (13)
OE	(5)	(6)	(12)	(12)
CEI	(2)	(1)	(3)	(3)
TE			(1)	(1)
JCP&L	(2)	(2)	(3)	(4)
Met-Ed	(2)	(2)	(5)	(4)
Penelec	(2)	(2)	(5)	(4)
Other FirstEnergy Subsidiaries	(12)	(8)	(19)	(16)
	$ (33)	**$ (28)**	**$ (62)**	**$ (57)**

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.

VIEs 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 $295 million was outstanding as of June 30, 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 primarily the result of net losses of the noncontrolling interests ($15 million) and distributions to owners ($4 million) during the six months ended June 30, 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.

PATH-WV

PATH, LLC was formed to construct, through its operating companies, the PATH Project, which is a high-voltage transmission line that was 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 $27 million at June 30, 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 that 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.

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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, except as described further below. 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 June 30, 2011, were $55 million, $47 million and $21 million for JCP&L, PE and WP, respectively and $120 million, $58 million and $26 million for the six months ended June 30, 2011, 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 and six months ended June 30, 2010 were $53 million and $117 million, respectively.

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 June 30, 2011, WP s reserve for this adverse purchase power commitment was $59 million, including a current liability of $11 million, and is being amortized over the life of the commitment.

Loss Contingencies

FirstEnergy has variable interests in certain sale and 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 and 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 June 30, 2011:

	Maximum Exposure	Discounted Lease Payments, net[(1)]	Net Exposure
		(In millions)	
FES	$ 1,348	$ 1,156	$ 192
OE	635	445	190
CEI[(2)]	624	69	555
TE[(2)]	624	303	321

(1) The net present value of FirstEnergy s consolidated sale and leaseback operating lease commitments is $1.6 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. During the second quarter of 2011, FirstEnergy reached a settlement with the IRS on a research and development claim and recognized approximately $30 million of income tax benefits, including $5 million that favorably affected FirstEnergy s effective tax rate for the second quarter and first six months of 2011. There were no other material changes to FirstEnergy s unrecognized income tax benefits during the first six months of 2011. After reaching a tentative agreement with the IRS on a tax item at appeals related to the capitalization of certain costs for tax years 2005-2008, as well as reaching a settlement on an unrelated state tax matter in the second quarter of 2010, FirstEnergy recognized approximately $70 million of net income tax benefits, including $13 million that favorably affected FirstEnergy s effective tax rate for the second quarter of 2010. The remaining portion of the income tax benefit recognized in the first six months of 2010 increased FirstEnergy s accumulated deferred income taxes for the settled temporary tax item.

As of June 30, 2011, it is reasonably possible that approximately $46 million of unrecognized income tax benefits may be resolved within the next twelve months, of which approximately $4 million, if recognized, would affect FirstEnergy s effective tax rate. The potential decrease in the amount of unrecognized income 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. The interest associated with the settlement of the claim noted above favorably affected FirstEnergy s effective tax rate by $6 million in the first half of 2011. During the first six months of 2011, there were no material changes to the amount of accrued interest, except for a $6 million increase in accrued interest as a result of the merger with Allegheny. The reversal of accrued interest associated with the recognized income tax benefits noted above favorably affected FirstEnergy s effective tax rate by $11 million in the first six months of 2010. The net amount of interest accrued as of June 30, 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 $28 million in the first six months 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 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.

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 June 30, 2011, outstanding guarantees and other assurances aggregated approximately $3.8 billion, consisting of parental guarantees ($0.8 billion), subsidiaries guarantees ($2.6 billion), and 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 believes the likelihood is remote that such parental guarantees of $0.2 billion (included in the $0.8 billion discussed above) as of June 30, 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 June 30, 2011, FirstEnergy s maximum exposure under these collateral provisions was $625 million, consisting of $522 million due to a below investment grade credit rating (of which $265 million is due to an acceleration of payment or funding obligation) and $103 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 $666 million.

Most of FirstEnergy s surety bonds are backed by various indemnities common within the insurance industry. Surety bonds and related guarantees of $136 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 portfolios as of June 30, 2011 and forward prices as of that date, FES and AE Supply have posted collateral of $138 million and $2 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 $17 million of collateral. Depending on the volume of forward contracts and future price movements, higher amounts for margining could be required to be posted.

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 would 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 due in October 2012. 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.

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 coal-fired 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 coal-fired plant based on modifications dating back to 1986. On March 31, 2011, the EPA proposed emissions limits and compliance schedules to reduce SO2 air emissions by approximately 81% at the Portland Plant based on an interstate pollution transport petition submitted by New Jersey under Section 126 of the CAA. The NOV also alleged NSR violations at the Keystone and Shawville coal-fired plants based on modifications dating back to 1984. Met-Ed, JCP&L, as the former owner of 16.67% of Keystone, and Penelec, as former owner and operator of Shawville, 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 coal-fired Homer City Plant 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 Homer City containing in all material respects allegations identical to those included in the June 2008 NOV. 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 Homer City 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 Homer City, 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 Homer City s air emissions as well as certification as a class action and to enjoin Homer City 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 Homer City seeking injunctive relief and civil penalties. Mission is seeking indemnification from Penelec, the co-owner and operator of Homer City prior to its sale in 1999. On April 21, 2011, Penelec and all other defendants filed Motions to Dismiss all of the federal claims and the various state claims. Responsive and Reply briefs were filed on May 26, 2011 and June 17, 2011, respectively. 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 coal-fired 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 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 Eastlake Plant. In June 2011, EPA issued another Finding of Violation and NOV alleging violations of the CAA and Ohio regulations, specifically opacity limitations and requirements to continuously operate opacity monitoring systems at the Eastlake, Lakeshore, Bay Shore and Ashtabula coal-fired plants. Also, in June 2011, FirstEnergy received an information request pursuant to section 114(a) of the CAA for certain operating maintenance and planning information, among other information regarding these plants. 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 an information request pursuant to section 114(a) of the CAA letter from the EPA requesting that it provide information and documentation relevant to the operation and maintenance of the following ten coal-fired plants, which collectively include 22 electric generation units Albright, Armstrong, Fort Martin, Harrison, Hatfield s Ferry, Mitchell, Pleasants, Rivesville, R. Paul Smith and Willow Island 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 plants: 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 coal-fired plants 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 Plants in Pennsylvania. On January 17, 2006, the PA DEP and the Attorneys General filed an amended complaint. A 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 Plants in Pennsylvania and the Fort Martin and Willow Island coal-fired plants 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 coal-fired plant for NO_X, SO_2 and mercury, based on a PJM declaration that the plant 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 coal-fired plant. 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 SO2 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 2011, the EPA finalized the Cross-State Air Pollution Rule (CSAPR) to replace CAIR, which remains in effect until CSAPR becomes effective (60 days after publication in the Federal Register). CSAPR requires reductions of NOx and SO2 emissions in two phases (2012 and 2014), ultimately capping SO2 emissions in affected states to 2.4 million tons annually and NOx emissions to 1.2 million tons annually. CSAPR allows trading of NOx and SO_2 emission allowances between power plants located in the same state and interstate trading of NOx and SO_2 emission allowances with some restrictions. FGCO s future cost of compliance may be substantial and changes to FirstEnergy s operations may result. Management is currently assessing the impact of CSAPR, other environmental proposals and other factors on FirstEnergy s competitive fossil generating facilities, including but not limited to, the impact on value of our emissions allowances (currently reflected at $38 million on our Consolidated Balance Sheet as of June 30, 2011) and the operations of its coal-fired plants.

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 (CO2) 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. On June 20, 2011, the U. S. Supreme Court reversed the Second Circuit. The Court remanded to the Second Circuit the issue of whether the CAA preempted state common law nuisance actions. The Court s ruling also failed to answer the question of the extent to which actions for damages may remain viable. While FirstEnergy is not a party to this litigation, in June 2011, FirstEnergy received notice of a complaint alleging that the GHG emissions of 87 companies, including FirstEnergy, render them liable for damages to certain residents of Mississippi stemming from Hurricane Katrina. On July 27, 2011, the plaintiff voluntarily dismissed FirstEnergy from this complaint.

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.

In 2004, the EPA established new performance standards under Section 316(b) of the Clean Water Act for reducing impacts on fish and shellfish from cooling water intake structures at certain existing 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). In 2007, the Court of Appeals for the Second Circuit invalidated portions of the Section 316(b) performance standards and 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. On July 19, 2011, the EPA extended the public comment period for the new proposed Section 316(b) regulation by 30 days but stated its schedule for issuing a final rule remains July 27, 2012. 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 coal-fired Bay Shore 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.

In May 2011, the West Virginia Highlands Conservancy, the West Virginia Rivers Coalition, and the Sierra Club filed a CWA citizen suit alleging violations of arsenic limits in the NPDES water discharge permit for the fly ash disposal site at the Albright coal-fired plant seeking unspecified civil penalties and injunctive relief. MP is currently seeking relief from the arsenic limits through WVDEP agency review. In June 2011, the West Virginia Highlands Conservancy, the West Virginia Rivers Coalition, and the Sierra Club served another 60-Day Notice of Intent required prior to filing a citizen suit under the Clean Water Act for alleged failure to obtain a permit to construct the fly ash impoundments at the Albright Station.

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

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 coal-fired plant. 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 in September 2011, however the Court stayed all prehearing deadlines on July 15, 2011 to allow the parties additional time to work out a settlement. 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. In May 2011, the EPA agreed with PA DEP s recommended sulfate impairment designation. PA DEP s goal is to submit a final water quality standards regulation, incorporating the sulfate impairment designation for EPA approval by May, 2013. PA DEP will then need to develop a TMDL limit for the river, a process that will take approximately 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.
The Little Blue Run (LBR) Coal Combustion By-products (CCB) impoundment is expected to run out of disposal capacity for disposal of CCBs from the Bruce Mansfield Plant between 2016 and 2018. In July 2011, BMP submitted a Phase I permit application to PA DEP for construction of a new dry CCB disposal facility adjacent to LBR. BMP anticipates submitting zoning applications for approval to allow construction of a new dry CCB disposal facility prior to commencing construction.

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 June 30, 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 $133 million (JCP&L $69 million, TE $1 million, CEI $1 million, FGCO $1 million and FirstEnergy $61 million) have been accrued through June 30, 2011. Included in the total are accrued liabilities of approximately $63 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. On July 11, 2011, FirstEnergy was found to be a potentially responsible party under CERCLA indirectly liable for a portion of past and future clean-up costs at certain legacy MGP sites, estimated to total approximately $59 million. FirstEnergy recognized additional expense of $29 million during the second quarter of 2011; $30 million had previously been reserved prior to 2011.

(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 yet to take 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 June 30, 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. As required by the NRC, FirstEnergy annually recalculates and adjusts the amount of its parental guarantee, as appropriate. The values of FirstEnergy s NDT 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 NDT. The NRC issued guidance anticipating an increase in low-level radioactive waste disposal costs associated with the decommissioning of 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. On June 24, 2011, FENOC submitted a $95 million parental guarantee to the NRC for its approval.

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, a 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 challenging whether FENOC s Environmental Report adequately evaluated (1) a combination of renewable energy sources as alternatives to the renewal of Davis-Besse s operating license, and (2) severe accident mitigation alternatives at Davis-Besse. On May 6, 2011, FENOC filed an appeal with the NRC Commissioners from the order granting a hearing on the Davis-Besse license renewal application.

On April 14, 2011, a group of environmental organizations petitioned the NRC Commissioners to suspend certain pending nuclear licensing proceedings, including the Davis-Besse license renewal proceeding, to ensure that any safety and environmental implications of the accident at the Fukushima Daiichi Nuclear Power Station in Japan are considered. By May 2, 2011, the NRC Staff, FENOC and much of the nuclear industry filed responses opposing the petition. On May 6, 2011, petitioners filed a supplemental reply.

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.

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 entered into a long term Coal Sales Agreement with AE Supply and MP for the supply of coal to the Harrison generating facility. 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 from January 10, 2011 through February 1, 2011. At trial, AE Supply and MP presented evidence that they have incurred in excess of $80 million in damages for replacement coal purchased through the end of 2010 and will incur additional damages in excess of $150 million for future shortfalls. 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 ($90 million in future damages and $14 million for replacement coal / interest). Post-trial filings occurred in May 2011, with Oral Argument on June 28, 2011. The parties expect a ruling sometime in the third quarter, at which time the judgment will be final. The parties have 30 days to appeal the final judgment. AE Supply and MP intend to vigorously pursue this matter through appeal if necessary but cannot predict its outcome.

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, ATSI and TrAIL. The NERC is the ERO 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 FERC will continue to refine existing reliability standards as well as to develop and adopt new reliability standards. The financial impact of complying with future 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 future 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.

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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, although a final determination has not yet been made by FERC.

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 investigations with regard to certain matters of compliance by Allegheny.

(B) MARYLAND

By statute enacted in 2007, the obligation of Maryland utilities to provide standard offer service (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. PE now conducts rolling auctions to procure the power supply necessary to serve its customer load pursuant to a plan approved by the MDPSC. 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 electric consumption be reduced by 10% and electricity demand be reduced by 15%, in each case by 2015.

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. 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. 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 and those programs are to be filed by September 1, 2011.

In March 2009, the MDPSC 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. 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. The Maryland legislature passed a bill on April 11, 2011, which 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 legislation directs the MDPSC to consider cost-effectiveness, and provides that the MDPSC 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, with proposed rules to be filed by September 15, 2011. Separately, on April 7, 2011, the MDPSC initiated a rulemaking with respect to issues related to contact voltage. On June 3, 2011, the MDPSC s Staff issued a report and draft regulations. Comments on the draft regulations were submitted on June 17, 2011, and a hearing was held July 7, 2011. Final regulations related to contact voltage have not yet been adopted.

(C) NEW JERSEY

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). In its order of June 15, 2011, the NJBPU adopted a Stipulation reached among JCP&L, the NJBPU Staff and the Division of Rate Counsel which resolved both Petitions, resulting in a net reduction in recovery of $0.8 million annually for all components of the SBC (including, as requested, a zero level of recovery of TMI-2 decommissioning costs).

(D) OHIO

The Ohio Companies operate under an ESP, which expires on May 31, 2014. The material terms of the ESP include: generation supplied through a CBP commencing June 1, 2011 (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 (FES is one of the wholesale suppliers to the Ohio Companies); 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. The Ohio Companies also agreed not to recover from retail customers certain costs related to transmission cost allocations by PJM as a result of ATSI s 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.

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 were 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. OE fell short of its statutory 2010 energy efficiency and peak demand reduction benchmarks and 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. The PUCO granted this request on May 19, 2011 for OE, finding that the motion was moot for CEI and TE. 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 them into compliance with their yet-to-be-defined modified benchmarks. On June 2, 2011, the Companies filed an application for rehearing to clarify the decision related to CEI and TE. 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. On May 4, 2011, the PUCO granted applications for rehearing for the purpose of further consideration; however, no substantive ruling has been issued.

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 and 0.50% of the KWH they served in 2010. In August and October 2009, the Ohio Companies conducted RFPs to secure RECs. 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 and 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. 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. Other parties to the proceeding filed comments asserting that the force majeure determination should not be granted, and others requesting the PUCO to review the costs the Ohio companies have incurred to comply with the renewable energy requirements. 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 PUCO modified and approved the companies application on May 25, 2011, ruling that the new credit be phased out over an eight-year period and granting authority for the companies to recover deferred costs and associated carrying charges. OCC filed applications for rehearing on June 24, 2011 and the Ohio Companies filed their responses on July 5, 2011. The PUCO has not yet acted on the applications for rehearing.

(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. Pursuant to the plan approved by the PPUC, Met-Ed and Penelec began to refund those amounts to customers in January 2011, and the refunds will continue over a 29 month period until the full amounts previously recovered for marginal transmission loses are refunded. 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. On June 14, 2011, the Commonwealth Court issued an opinion and order affirming the PPUC s Order to the extent that it holds that line loss costs are not transmission costs and, therefore, the approximately $254 million in marginal transmission losses and associated carrying charges for the period prior to January 1, 2011, are not recoverable under Met-Ed s and Penelec s TSC riders. Met-Ed and Penelec filed a Petition for Allowance of Appeal with the Pennsylvania Supreme Court and also a complaint seeking relief in federal district court. Although the ultimate outcome of this matter cannot be determined at this time, Met-Ed and Penelec believe that they should ultimately prevail through the judicial process and therefore expect to fully recover the approximately $254 million ($189 million for Met-Ed and $65 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.

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).

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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. On February 18, 2011, the companies filed a petition to approve their First Amended EE&C Plans. On June 28, 2011, a hearing on the petition was held before an administrative law judge.

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 Met-Ed, Penelec and Penn 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 Met-Ed, Penelec and Penn, 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. 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, 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 OCA 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. One party retained the ability to challenge the recovery of amounts spent on WP s original smart meter implementation plan. 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. On May 3, 2011, the ALJ issued an Initial Decision recommending that the PPUC approve the Amended Joint Petition for Full Settlement. The PPUC approved the Initial Decision by order entered June 30, 2011.

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. On April 29, 2011, the PPUC entered an Order initiating the investigation and requesting comments from interested parties on eleven directed questions. Met-Ed, Penelec, Penn Power and West Penn submitted joint comments on June 3, 2011. FES also submitted comments on June 3, 2011. On June 8, 2011, the PPUC conducted an en banc hearing on these issues at which both the Pennsylvania Companies and FES participated and offered testimony.

(F) VIRGINIA

In September 2010, PATH-VA filed an application with the VSCC for authorization to construct the Virginia portions of the PATH Project. On February 28, 2011, PATH-VA filed a motion to withdraw the application. On May 24, 2011, the VSCC granted PATH-VA s motion to withdraw its application for authorization to construct the Virginia portions of the PATH Project. 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, which was amended through subsequent filings. MP and PE ultimately requested an annual increase in retail rates of approximately $95 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. A hearing was held at the WVPSC on June 13, 2011. An order is expected by late September 2011.

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 and 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 and Morgantown Energy Associates, each the owner of one of the contracted resources, has participated in the case in opposition to the Petition.

(H) FERC MATTERS

Rates for Transmission Service Between MISO and PJM

In November 2004, FERC issued an order eliminating the through and out rate for transmission service between the MISO and PJM regions. 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, 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 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 FERC in November 2010, and the relevant payments made. The subsidiaries of Allegheny entered into nine settlements to fix their liability for SECA charges with various parties. All of the settlements were approved by FERC and the relevant payments have been made for eight of the settlements. Payments due under the remaining settlement will be made as a part of the refund obligations of the Utilities that are under review by FERC as part of a compliance filing. Potential refund obligations of FirstEnergy and the Allegheny subsidiaries 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.

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 a paper hearing" meaning that FERC called for parties to submit written comments 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 FERC.

RTO Realignment

On June 1, 2011, ATSI and the ATSI zone entered into PJM. The move was performed as planned with no known operational or reliability issues for ATSI or for the wholesale transmission customers in the ATSI zone.

On February 1, 2011, ATSI in conjunction with PJM filed its proposal with FERC for moving its transmission rate into PJM s tariffs. 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 amendments to 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.

On May 31, 2011, FERC issued orders that address the proposed ATSI transmission rate, and certain parts of the MISO tariffs that reflect the mechanics of transmission cost allocation and collection. In its May 31, 2011 orders, FERC approved ATSI s proposal to move the ATSI formula rate into the PJM tariff without significant change. Speaking to ATSI s proposed treatment of the MISO s exit fees and charges for transmission costs that were allocated to the ATSI zone, FERC required ATSI to present a cost-benefit study that demonstrates that the benefits of the move for transmission customers exceed the costs of any such move, which FERC had not previously required. Accordingly, FERC ruled that these costs must be removed from ATSI s proposed transmission rates until such time as ATSI files and FERC approves the cost-benefit study. On June 30, 2011, ATSI submitted the compliance filing that removed the MISO exit fees and transmission cost allocation charges from ATSI s proposed transmission rates. Also on June 30, 2011, ATSI requested rehearing of FERC s decision to require a cost-benefit study analysis as part of FERC s evaluation of ATSI s proposed transmission rates. The compliance filing, and ATSI s request for rehearing, are currently pending before FERC.

From late April 2011 through June 2011, FERC issued other orders that address ATSI s move into PJM. These orders approve ATSI s proposed interconnection agreements for large wholesale transmission customers and generators, and revisions to the PJM and MISO tariffs that reflect ATSI s move into PJM. In addition, FERC approved an Exit Fee Agreement that memorializes the agreement between ATSI and MISO with regard to ATSI s obligation to pay certain administrative charges to the MISO upon exit. Finally, ATSI and the MISO were able to negotiate an agreement of ATSI s responsibility for certain charges associated with long term firm transmission rights that, according to the MISO, were payable by the ATSI zone upon its departure from the MISO. ATSI did not and does not agree that these costs should be charged to ATSI but, in order to settle the case and all claims associated with the case, ATSI agreed to a one-time payment of $1.8 million to the MISO. This settlement agreement has been submitted for FERC s review and approval. The final outcome of those proceedings that address the remaining open issues related to ATSI s move into PJM and their impact, if any, on FirstEnergy cannot be predicted at this time.

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 transmission projects that are approved via MISO s formal transmission planning process (the MTEP). 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 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 MVPs 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 that had been made 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 attached 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.

As noted above, on February 1, 2011, ATSI filed proposed transmission rates related to its move into PJM. The proposed rates included line items that were intended to recover all MVP costs (if any) that might be charged to ATSI or to the ATSI zone. In its May 31, 2011 order on ATSI s proposed transmission rates FERC ruled that ATSI must submit a cost-benefit study before ATSI can recover the MVP costs. FERC further directed that ATSI remove the line-items from ATSI s formula rate that would recover the MVP costs until such time as ATSI submits and FERC approves the cost- benefit study. ATSI requested a rehearing of these parts of FERC s order and, pending this further legal process, has removed the MVP line items from its transmission rates.

FirstEnergy cannot predict the outcome of these proceedings at this time.

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 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 FERC, which arises out of claims previously filed with 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 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. On May 4, 2011, FERC affirmed the judge s ruling.

In June 2009, the California Attorney General, on behalf of certain California parties, filed a second complaint with 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 including AE Supply in this new complaint. AE Supply filed a motion to dismiss the Brown complaint that was granted by FERC on May 24, 2011. On June 23, 2011, the California Attorney General requested rehearing of the May 24, 2011 order. FirstEnergy cannot predict the outcome of this matter.

Transmission Expansion

TrAIL Project. TrAIL is a 500 kV transmission line extending from southwest Pennsylvania through West Virginia and into northern Virginia. Effective May 19, 2011, all segments of TrAIL were energized and in service.

PATH Project. The PATH Project is comprised of a 765 kV transmission line that was 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. 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 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. The WVPSC and VSCC have granted the motions 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.

Seneca Pumped Storage Project Relicensing

The Seneca (Kinzua) Pumped Storage Project is a 451 MW hydroelectric project located in Warren County, Pennsylvania owned and operated by FGCO. FGCO holds the current FERC license that authorizes ownership and operation of the project. The current FERC license will expire on November 30, 2015. FERC s regulations call for a five-year relicensing process. On November 24, 2010, and acting pursuant to applicable FERC regulations and rules, FGCO initiated the relicensing process by filing its notice of intent to relicense and pre-application document (PAD) in the license docket.

On November 30, 2010, the Seneca Nation of Indians filed its notice of intent to relicense and PAD documents necessary for them to submit a competing application. Section 15 of the FPA contemplates that third parties may file a competing application to assume ownership and operation of a hydroelectric facility upon (i) relicensure and (ii) payment of net book value of the plant to the original owner/operator. Nonetheless, FGCO believes it is entitled to a statutory incumbent preference under Section 15.

The Seneca Nation and certain other intervenors have asked FERC to redefine the project boundary of the hydroelectric plant to include the dam and reservoir facilities operated by the U.S. Army Corps. of Engineers. On May 16, 2011, FirstEnergy filed a Petition for Declaratory Order with FERC seeking an order to exclude the dam and reservoir facilities from the project. The Seneca Nation, the New York State Department of Environmental Conservation, and the U.S. Department of Interior each submitted responses to FirstEnergy s petition, including motions to dismiss FirstEnergy s petition. The project boundary issue is pending before FERC.

The next steps in the relicensing process are for FirstEnergy and the Seneca Nation to define and perform certain environmental and operational studies to support their respective applications. These steps are expected to run through approximately November of 2013. FirstEnergy cannot predict the outcome of these proceedings at this time.

11. STOCK-BASED COMPENSATION PLANS

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

Allegheny s stock-based awards were converted into FirstEnergy 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.

(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 5.6 million shares available for future awards as of June 30, 2011.

Restricted Stock and Restricted Stock Units

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

	Six Months Ended June 30, 2011
Restricted stock and stock units outstanding as of January 1, 2011	1,878,022
Granted	891,881
Converted Allegheny restricted stock	645,197
Exercised	(428,686)
Forfeited	(71,775)
Restricted stock and stock units outstanding as of June 30, 2011	2,914,639

The 891,881 shares of restricted common stock granted during the six months ended June 30, 2011 had a grant-date fair value of $33.2 million and a weighted-average vesting period of 2.74 years.

Restricted stock units include awards that will be settled in a specific number of shares of common 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 common stock based on FirstEnergy s performance compared to annual target performance metrics.

Compensation expense recognized during the six months ended June 30, 2011 and 2010 for restricted stock and restricted stock units, net of amounts capitalized, was approximately $27 million and $20 million, respectively.

Stock Options

Stock option activity for the six months ended June 30, 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	(691,304)	31.38
Options forfeited/expired	(78,978)	71.71
Stock options outstanding as of June 30, 2011	4,586,717	$ 38.09

(3,924,595 options exercisable)

Compensation expense recognized for stock options during the six months ended June 30, 2011 was $0.3 million. No expense was recognized during the six months ended June 30, 2010. Options granted during the six months ended June 30, 2011 had a grant-date fair value of $3.3 million and an expected weighted-average vesting period of 3.79 years.

Options outstanding by exercise price as of June 30, 2011 were as follows:

Exercise Prices		Shares Under Options	Weighted Average Exercise Price	Remaining Contractual Life in Years
$20.02	$30.74	1,045,122	$ 26.54	2.02
$30.89	$40.93	3,160,440	37.30	4.17
$42.72	$51.82	3,883	51.02	0.70
$53.06	$62.97	54,559	56.15	3.02
$64.52	$71.82	9,042	67.50	5.24
$73.39	$80.47	311,003	80.17	3.81
$81.19	$89.59	2,668	85.39	6.09
Total		4,586,717	$ 38.08	3.64

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 six months ended June 30, 2011 and 2010, net of amounts capitalized, totaled $2 million and $(6) million, respectively. No performance shares under the FirstEnergy LTIP were settled during the six months ended June 30, 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 six months ended June 30, 2011 and 2010, net of amounts capitalized and dividends on common stock, were $19 million and $10 million, respectively.

(C) EDCP

There was no material compensation expense recognized on EDCP stock units during the six months ended June 30, 2011 and 2010.

(D) DCPD

DCPD expenses recognized during the six months ended June 30, 2011 and 2010 were approximately $2 million in each period. The net liability recognized for DCPD of approximately $6 million as of June 30, 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 June 30, 2011.

12. NEW ACCOUNTING STANDARDS AND INTERPRETATIONS

In May 2011, the FASB amended authoritative accounting guidance regarding fair value measurement. The amendment prohibits the application of block discounts for all fair value measurements, permits the fair value of certain financial instruments to be measured on the basis of the net risk exposure and allows the application of premiums or discounts to the extent consistent with the applicable unit of account. The amendment clarifies that the highest-and-best use and valuation-premise concepts are not relevant to financial instruments. Expanded disclosures are required under the amendment, including quantitative information about significant unobservable inputs used for Level 3 measurements, a qualitative discussion about the sensitivity of recurring Level 3 measurements to changes in unobservable inputs disclosed, a discussion of the Level 3 valuation processes, any transfers between Levels 1 and 2 and the classification of items whose fair value is not recorded but is disclosed in the notes. The amendment is effective for FirstEnergy in the first quarter of 2012. FirstEnergy does not expect this amendment to have a material effect on its financial statements.

In June 2011, the FASB issued new accounting guidance that revises the manner in which entities presents comprehensive income in their financial statements. The new guidance requires entities to report components of comprehensive income in either a continuous statement of comprehensive income or two separate but consecutive statements. The new guidance does not change the items that must be reported in other comprehensive income and does not affect the calculation or reporting of earnings per share. The amendment is effective for FirstEnergy in the first quarter of 2012. This amendment will not have a material effect on 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 used 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 was comprised of 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/Corporate 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 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.

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, Maryland, New Jersey and New York, and purchases power for its POLR, SOS and default service requirements in Ohio, Pennsylvania, New Jersey and Maryland. 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, SOS 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 investment 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 previously dedicated to MISO were integrated into the PJM market. All of FirstEnergy s assets now reside in 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 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 (prior to June 1, 2011) to deliver energy to the segment s customers.

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

Segment Financial Information

Three Months Ended	Regulated Distribution	Competitive Energy Services	Regulated Independent Transmission	Other/ Corporate	Reconciling Adjustments	Consolidated
			(In millions)			
June 30, 2011						
External revenues	$ 2,485	$ 1,495	$ 105	$ (30)	$ (7)	$ 4,048
Internal revenues		318			(306)	12
Total revenues	2,485	1,813	105	(30)	(313)	4,060
Depreciation and amortization	240	107	18	7		372
Investment income (loss), net	27	15		1	(12)	31
Net interest charges	145	67	11	21	1	245
Income taxes	108	7	18	(30)	(2)	101
Net income (loss)	184	12	31	(51)	(5)	171
Total assets	26,932	17,146	2,339	1,179		47,596
Total goodwill	5,551	905				6,456
Property additions	302	197	45	25		569
June 30, 2010						
External revenues	$ 2,314	$ 795	$ 59	$ (21)	$ (8)	$ 3,139
Internal revenues	19	539			(558)	
Total revenues	2,333	1,334	59	(21)	(566)	3,139
Depreciation and amortization	264	71	13	3		351
Investment income (loss), net	28	13			(10)	31
Net interest charges	124	33	5	9	(4)	167
Income taxes	81	75	7	(12)	(17)	134
Net income (loss)	132	121	11	(20)	12	256
Total assets	21,457	11,102	993	914		34,466
Total goodwill	5,551	24				5,575
Property additions	157	290	15	27		489
Six Months Ended						
June 30, 2011						
External revenues	$ 4,753	$ 2,736	$ 172	$ (53)	$ (16)	$ 7,592
Internal revenues		661			(617)	44
Total revenues	4,753	3,397	172	(53)	(633)	7,636
Depreciation and amortization	485	195	31	13		724
Investment income (loss), net	52	21		1	(22)	52
Net interest charges	276	122	20	40		458
Income taxes	164	10	25	(50)	30	179
Net income (loss)	280	17	44	(86)	(39)	216

Total assets	26,932	17,146	2,339	1,179		47,596
Total goodwill	5,551	905				6,456
Property additions	479	411	72	56		1,018
June 30, 2010						
External revenues	$ 4,798	$ 1,514	$ 116	$ (43)	$ (14)	$ 6,371
Internal revenues	19	1,213			(1,165)	67
Total revenues	4,817	2,727	116	(43)	(1,179)	6,438
Depreciation and amortization	577	148	25	6		756
Investment income (loss), net	54	14		1	(22)	47
Net interest charges	248	66	10	22	(7)	339
Income taxes	143	117	14	(24)	(5)	245
Net income (loss)	235	190	23	(39)	(4)	405
Total assets	21,457	11,102	993	914		34,466
Total goodwill	5,551	24				5,575
Property additions	309	619	29	40		997

Reconciling adjustments 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. The following events described in the sections below occurred during for the first six months of 2011 that indicated the carrying value of certain assets may not be recoverable.

Fremont Energy Center

On March 11, 2011, FirstEnergy and American Municipal Power, Inc., 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 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 July 28, 2011, FirstEnergy closed the sale of Fremont Energy Center to American Municipal Power, Inc.

Peaking Facilities

During the first six months of 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. FirstEnergy recorded impairment charges of $7 million and $21 million during the three months and six months ended June 30, 2011, respectively, as a result of the recoverability evaluation.

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, OE and TE primarily relate to the decommissioning of the Beaver Valley, Davis-Besse and Perry nuclear generating facilities (OE for its leasehold interest in Beaver Valley Unit 2 and Perry and TE for its leasehold interest in Beaver Valley Unit 2). The ARO liabilities for JCP&L, Met-Ed and Penelec primarily relate to the decommissioning of the TMI-2 nuclear generating facility. FES, OE, JCP&L, Met-Ed and Penelec use an expected cash flow approach to measure the fair value of their nuclear decommissioning ARO.

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.

During the second quarter of 2011, studies were completed to update the estimated cost of decommissioning the Davis-Besse nuclear facility. The cost studies resulted in a revision to the estimated cash flows associated with the ARO liabilities of FES and reduced the liability for FES in the amount of $5 million.

The revisions to the estimated cash flows had no significant impact on accretion of the obligation during the three months and six months ended June 30, 2011 when compared to the same periods of 2010.

16. SUPPLEMENTAL GUARANTOR INFORMATION

In 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 and six month periods ended June 30, 2011 and 2010, consolidating balance sheets as of June 30, 2011 and December 31, 2010 and consolidating statements of cash flows for the three months ended June 30, 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.

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

For the Three Months Ended June 30, 2011	FES	FGCO	NGC	Eliminations	Consolidated
			(In millions)		
REVENUES	$ 1,275	$ 535	$ 393	$ (911)	$ 1,292
EXPENSES:					
Fuel	6	266	44		316
Purchased power from affiliates	902	9	65	(911)	65
Purchased power from non-affiliates	332	(3)			329
Other operating expenses	159	115	143	12	429
Provision for depreciation	1	32	36	(1)	68
General taxes	16	8	6		30
Impairment of long-lived assets		7			7
Total expenses	1,416	434	294	(900)	1,244
OPERATING INCOME (LOSS)	(141)	101	99	(11)	48
OTHER INCOME (EXPENSE):					
Investment income		1	15		16
Miscellaneous income (expense), including net income from equity investees	123	1		(120)	4
Interest expense affiliates		(1)	(1)		(2)
Interest expense other	(24)	(28)	(16)	16	(52)
Capitalized interest		5	5		10
Total other income (expense)	99	(22)	3	(104)	(24)
INCOME (LOSS) BEFORE INCOME TAXES	(42)	79	102	(115)	24
INCOME TAXES (BENEFITS)	(62)	25	38	3	4
NET INCOME	$ 20	$ 54	$ 64	$ (118)	$ 20

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

For the Six Months Ended June 30, 2011	FES	FGCO	NGC	Eliminations	Consolidated
			(In millions)		
REVENUES	$ 2,642	$ 1,278	$ 862	$ (2,098)	$ 2,684
EXPENSES:					
Fuel	7	560	92		659
Purchased power from affiliates	2,087	11	134	(2,098)	134
Purchased power from non-affiliates	629	(3)			626
Other operating expenses	321	233	331	25	910
Provision for depreciation	2	63	74	(3)	136
General taxes	27	19	14		60
Impairment charges of long-lived assets		20			20
Total expenses	3,073	903	645	(2,076)	2,545
OPERATING INCOME (LOSS)	(431)	375	217	(22)	139
OTHER INCOME (EXPENSE):					
Investment income	1	1	20		22
Miscellaneous income, including net income from equity investees	356	2		(350)	8
Interest expense affiliates	(1)	(1)	(1)		(3)
Interest expense other	(48)	(56)	(33)	32	(105)
Capitalized interest		10	10		20
Total other income (expense)	308	(44)	(4)	(318)	(58)
INCOME (LOSS) BEFORE INCOME TAXES	(123)	331	213	(340)	81
INCOME TAXES (BENEFITS)	(179)	119	80	5	25
NET INCOME	$ 56	$ 212	$ 133	$ (345)	$ 56

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

For the Three Months Ended June 30, 2010	FES	FGCO	NGC	Eliminations	Consolidated
			(In millions)		
REVENUES	$ 1,307	$ 581	$ 339	$ (901)	$ 1,326
EXPENSES:					
Fuel	7	302	34		343
Purchased power from affiliates	913	8	49	(901)	69
Purchased power from non-affiliates	310				310
Other operating expenses	81	94	117	12	304
Provision for depreciation	1	27	36	(1)	63
General taxes	6	9	7		22
Total expenses	1,318	440	243	(890)	1,111
OPERATING INCOME (LOSS)	(11)	141	96	(11)	215
OTHER INCOME (EXPENSE):					
Investment income	2		11		13
Miscellaneous income, including net income from equity investees	151	1		(148)	4
Interest expense affiliates		(2)			(2)
Interest expense other	(24)	(28)	(15)	16	(51)
Capitalized interest		20	4		24
Total other income (expense)	129	(9)		(132)	(12)
INCOME BEFORE INCOME TAXES	118	132	96	(143)	203
INCOME TAXES (BENEFITS)	(16)	48	34	3	69
NET INCOME	$ 134	$ 84	$ 62	$ (146)	$ 134

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

For the Six Months Ended June 30, 2010	FES	FGCO	NGC *(In millions)*	Eliminations	Consolidated
REVENUES	$ 2,674	$ 1,149	$ 765	$ (1,874)	$ 2,714
EXPENSES:					
Fuel	12	582	77		671
Purchased power from affiliates	1,881	12	111	(1,874)	130
Purchased power from non-affiliates	760				760
Other operating expenses	134	194	256	24	608
Provision for depreciation	2	54	73	(3)	126
General taxes	11	24	14		49
Impairment of long-lived assets		2			2
Total expenses	2,800	868	531	(1,853)	2,346
OPERATING INCOME (LOSS)	(126)	281	234	(21)	368
OTHER INCOME (EXPENSE):					
Investment income	4		10		14
Miscellaneous income, including net income from equity investees	317	1		(311)	7
Interest expense to affiliates		(4)	(1)		(5)
Interest expense other	(48)	(54)	(31)	32	(101)
Capitalized interest		36	8		44
Total other income (expense)	273	(21)	(14)	(279)	(41)
INCOME BEFORE INCOME TAXES	147	260	220	(300)	327
INCOME TAXES (BENEFITS)	(67)	97	78	5	113
NET INCOME	$ 214	$ 163	$ 142	$ (305)	$ 214

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FIRSTENERGY SOLUTIONS CORP.
CONDENSED CONSOLIDATING BALANCE SHEETS
(Unaudited)

As of June 30, 2011	FES	FGCO	NGC	Eliminations	Consolidated
			(In millions)		
ASSETS					
CURRENT ASSETS:					
Cash and cash equivalents	$	$ 6	$	$	$ 6
Receivables-					
Customers	450				450
Associated companies	481	425	263	(679)	490
Other	24	23	4		51
Notes receivable from associated companies	6	410	74		490
Materials and supplies, at average cost	54	253	192		499
Derivatives	221				221
Prepayments and other	34	14	1		49
	1,270	1,131	534	(679)	2,256
PROPERTY, PLANT AND EQUIPMENT:					
In service	101	6,105	5,634	(385)	11,455
Less Accumulated provision for depreciation	19	2,067	2,298	(178)	4,206
	82	4,038	3,336	(207)	7,249
Construction work in progress	10	198	486		694
Property, plant and equipment held for sale, net		487			487
	92	4,723	3,822	(207)	8,430
INVESTMENTS:					
Nuclear plant decommissioning trusts			1,184		1,184
Investment in associated companies	5,302			(5,302)	
Other	1	9			10
	5,303	9	1,184	(5,302)	1,194
DEFERRED CHARGES AND OTHER ASSETS:					
Accumulated deferred income tax benefits	18	344		(362)	
Customer intangibles	129				129
Goodwill	24				24
Property taxes		16	25		41

Unamortized sale and leaseback costs		6		70	76
Derivatives	135				135
Other	39	97	7	(68)	75
	345	463	32	(360)	480
	$ 7,010	$ 6,326	$ 5,572	$ (6,548)	$ 12,360
LIABILITIES AND CAPITALIZATION					
CURRENT LIABILITIES:					
Currently payable long-term debt	$ 1	$ 436	$ 671	$ (20)	$ 1,088
Short-term borrowings-					
Associated companies	453	88			541
Other		1			1
Accounts payable-					
Associated companies	665	231	165	(668)	393
Other	80	111			191
Derivatives	242				242
Other	69	137	46	10	262
	1,510	1,004	882	(678)	2,718
CAPITALIZATION:					
Total equity	3,858	2,728	2,556	(5,285)	3,857
Long-term debt and other long-term obligations	1,483	2,050	706	(1,239)	3,000
	5,341	4,778	3,262	(6,524)	6,857
NONCURRENT LIABILITIES:					
Deferred gain on sale and leaseback transaction				942	942
Accumulated deferred income taxes			504	(288)	216
Asset retirement obligations		28	847		875
Retirement benefits	50	245			295
Lease market valuation liability		194			194
Derivatives	85				85
Other	24	77	77		178
	159	544	1,428	654	2,785
	$ 7,010	$ 6,326	$ 5,572	$ (6,548)	$ 12,360

FIRSTENERGY SOLUTIONS CORP.
CONDENSED CONSOLIDATING BALANCE SHEETS
(Unaudited)

As of December 31, 2010	FES	FGCO	NGC	Eliminations	Consolidated
			(In millions)		
ASSETS					
CURRENT ASSETS:					
Cash and cash equivalents	$	$ 9	$	$	$ 9
Receivables-					
Customers	366				366
Associated companies	333	357	126	(338)	478
Other	21	56	13		90
Notes receivable from associated companies	34	189	174		397
Materials and supplies, at average cost	41	276	228		545
Derivatives	182				182
Prepayments and other	48	10	1		59
	1,025	897	542	(338)	2,126
PROPERTY, PLANT AND EQUIPMENT:					
In service	96	6,198	5,412	(385)	11,321
Less Accumulated provision for depreciation	17	2,020	2,162	(175)	4,024
	79	4,178	3,250	(210)	7,297
Construction work in progress	9	520	534		1,063
	88	4,698	3,784	(210)	8,360
INVESTMENTS:					
Nuclear plant decommissioning trusts			1,146		1,146
Investment in associated companies	4,942			(4,942)	
Other		12			12
	4,942	12	1,146	(4,942)	1,158
DEFERRED CHARGES AND OTHER ASSETS:					
Accumulated deferred income tax benefits	43	412		(455)	
Customer intangibles	134				134
Goodwill	24				24
Property taxes		16	25		41
Unamortized sale and leaseback costs		10		63	73
Derivatives	98				98

Other	21	71	14	(58)	48
	320	509	39	(450)	418
	$ 6,375	$ 6,116	$ 5,511	$ (5,940)	$ 12,062
LIABILITIES AND CAPITALIZATION					
CURRENT LIABILITIES:					
Currently payable long-term debt	$ 101	$ 419	$ 632	$ (20)	$ 1,132
Short-term borrowings-					
Associated companies		12			12
Accounts payable-					
Associated companies	351	213	250	(347)	467
Other	139	102			241
Derivatives	266				266
Other	56	183	46	37	322
	913	929	928	(330)	2,440
CAPITALIZATION:					
Common stockholder s equity	3,788	2,515	2,414	(4,929)	3,788
Long-term debt and other long-term obligations	1,519	2,119	793	(1,250)	3,181
	5,307	4,634	3,207	(6,179)	6,969
NONCURRENT LIABILITIES:					
Deferred gain on sale and leaseback transaction				959	959
Accumulated deferred income taxes			448	(390)	58
Asset retirement obligations		27	865		892
Retirement benefits	48	237			285
Lease market valuation liability		217			217
Derivatives	81				81
Other	26	72	63		161
	155	553	1,376	569	2,653
	$ 6,375	$ 6,116	$ 5,511	$ (5,940)	$ 12,062

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

For the Six Months Ended June 30, 2011	FES	FGCO	NGC	Eliminations	Consolidated
			(In millions)		
NET CASH PROVIDED FROM (USED FOR) OPERATING ACTIVITIES	$ (329)	$ 321	$ 200	$ (10)	$ 182
CASH FLOWS FROM FINANCING ACTIVITIES:					
New Financing-					
Long-term debt		140	107		247
Short-term borrowings, net	453	77			530
Redemptions and Repayments-					
Long-term debt	(135)	(192)	(155)	10	(472)
Other	(9)	(1)	(1)		(11)
Net cash provided from (used for) financing activities	309	24	(49)	10	294
CASH FLOWS FROM INVESTING ACTIVITIES:					
Property additions	(6)	(109)	(219)		(334)
Sales of investment securities held in trusts			513		513
Purchases of investment securities held in trusts			(545)		(545)
Loans to associated companies, net	28	(221)	100		(93)
Customer acquisition costs	(2)				(2)
Other		(18)			(18)
Net cash provided from (used for) investing activities	20	(348)	(151)		(479)
Net change in cash and cash equivalents		(3)			(3)
Cash and cash equivalents at beginning of period		9			9
Cash and cash equivalents at end of period	$	$ 6	$	$	$ 6

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

For the Six Months Ended June 30, 2010	FES	FGCO	NGC	Eliminations	Consolidated
			(In millions)		
NET CASH PROVIDED FROM (USED FOR) OPERATING ACTIVITIES	$ (223)	$ 163	$ 287	$ (9)	$ 218
CASH FLOWS FROM FINANCING ACTIVITIES:					
New Financing-					
Short-term borrowings, net		76			76
Redemptions and Repayments-					
Long-term debt		(261)	(43)	9	(295)
Other	(1)				(1)
Net cash used for financing activities	(1)	(185)	(43)	9	(220)
CASH FLOWS FROM INVESTING ACTIVITIES:					
Property additions	(4)	(333)	(229)		(566)
Proceeds from asset sales		116			116
Sales of investment securities held in trusts			957		957
Purchases of investment securities held in trusts			(979)		(979)
Loans to associated companies, net	332	241	58		631
Customer acquisition costs	(105)				(105)
Leasehold improvement payments to associated companies			(51)		(51)
Other	1	(2)			(1)
Net cash provided from (used for) investing activities	224	22	(244)		2
Net change in cash and cash equivalents					
Cash and cash equivalents at beginning of period					
Cash and cash equivalents at end of period	$	$	$	$	$

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. were $181 million, or basic and diluted earnings of $0.43 per share of common stock, compared with $265 million, or basic and diluted earnings of $0.87 per share of common stock in the second quarter of 2010. Earnings available to FirstEnergy Corp. in the first six months of 2011 were $231 million or basic and diluted earnings of $0.61 per share of common stock, compared with $420 million or basic earnings of $1.38 ($1.37 diluted) per share of common stock in the first six months of 2010. The principal reasons for the decreases are summarized below.

Change In Basic Earnings Per Share From Prior Year[1]	**Three Months Ended June 30**	**Six Months Ended June 30**
Basic Earnings Per Share - 2010	$ 0.87	$ 1.38
Non-core asset sales/impairments	(0.01)	(0.04)
Trust securities impairments	0.01	0.02
Mark-to-market adjustments	(0.10)	(0.02)
Income tax charge from healthcare legislation - 2010		0.04
Regulatory charges - 2011	(0.01)	(0.05)
Regulatory charges - 2010		0.08
Litigation resolution	(0.06)	(0.07)
Merger related costs	(0.02)	(0.31)
Segment operating results - [2]		
Regulated Distribution	0.02	
Competitive Energy Services	(0.15)	(0.24)
Interest expense, net of amounts capitalized	(0.04)	(0.08)
Merger accounting commodity contracts	(0.08)	(0.12)
Net merger accretion[3]	0.02	0.06
Settlement of uncertain tax positions	(0.03)	(0.05)
Other expenses	0.01	0.01
Basic Earnings Per Share - 2011	$ 0.43	$ 0.61

(1) Amounts shown are net of income tax effect

(2) Excludes amounts that are shown separately

(3) 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 $7 million of merger transaction costs during each of the second quarter of 2011 and 2010, and approximately $89 million and $21 million of merger transaction costs during the first six months of 2011 and 2010, respectively. These costs are included in Other operating expenses in the Consolidated Statements of Income. FirstEnergy s consolidated financial statements include Allegheny s results of operations and financial position effective February 25, 2011. In addition, during the three months ended June 30, 2011, $10 million of merger integration costs and $8 million of charges from merger settlements approved by regulatory agencies were recognized. In the first six months of 2011, $85 million of merger integration costs and $32 million of charges from merger settlements approved by regulatory agencies were recognized. Charges resulting from merger settlements are not expected to be material in future periods.

FirstEnergy expects to achieve the 2011 merger benefits target resulting from the merger with Allegheny. Through June 2011, FirstEnergy has taken actions and completed savings initiatives that will allow the company to capture merger benefits of approximately $132 million pre-tax on an annual basis, or 63% of the $210 million annual target. The $132 million realized from savings initiatives completed through June, along with the impact of initiatives still underway, will be reflected in earnings throughout 2011.

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Operational Matters

TrAIL

On May 19, 2011, TrAIL s 500-kV transmission line, spanning more than 150 miles from southwestern Pennsylvania through West Virginia to northern Virginia, was completed and energized.

ATSI Integrated into PJM

On June 1, 2011, ATSI successfully integrated into PJM. With this transition, all of FirstEnergy s generation, transmission and distribution facilities are now in PJM.

Perry Refueling

On June 7, 2011, the Perry Plant returned to service following a scheduled shutdown for refueling and maintenance which began on April 18, 2011. During the outage, 248 of the 748 fuel assemblies were replaced and safety inspections were successfully conducted. Additionally, numerous preventative maintenance activities and improvement projects were completed that we believe will result in continued safe and reliable operations, including replacement of several control rod blades, rewind of the generator, and routine work on more than 150 valves, pumps and motors.

New Nuclear Emergency Operations Facilities

In June 2011, FENOC broke ground for new Emergency Operations Facilities for the Beaver Valley Power Station and Perry Nuclear Power Plant. Each of the 12,000 square-foot facilities will house activities related to maintaining public health and safety during the unlikely event of an emergency at the plant and allow for improved coordination between the plant, state and local emergency management agencies. FENOC is expected to break ground for a similar facility for the Davis-Besse Nuclear Power Station in August 2011.

Fremont Energy Center

On July 28, 2011, FirstEnergy closed on the previously announced sale of Fremont Energy Center to American Municipal Power, Inc. for $510 million based on 685 MW of output. The purchase price can be incrementally increased, not to exceed an additional $16 million, to reflect additional transmission export capacity up to 707 MW.

Financial Matters

On April 29, 2011, Met-Ed redeemed $13.69 million of pollution control revenue bonds at par value.

On May 4, 2011, AE terminated its $250 million credit facility due to other available funding sources following completion of the merger with FirstEnergy.

On May 31, 2011, JCP&L and Met-Ed repurchased $500 million and $150 million, respectively, of their equity from FirstEnergy to maintain an appropriate capital structure.

On June 1, 2011, FGCO repurchased $40 million of pollution control revenue bonds and is holding those bonds for future remarketing or refinancing.

On June 17, 2011, FirstEnergy and certain of its subsidiaries entered into two 5-year revolving credit facilities with a total borrowing capacity of $4.5 billion. These facilities consist of a $2 billion revolving credit facility for FirstEnergy and its regulated entities and a $2.5 billion revolving credit facility for FES and AE Supply. Prior separate facilities ($2.75 billion at FirstEnergy, $1 billion at AE Supply, $110 million at MP, $150 million at PE and $200 million at WP) were terminated.

On July 29, 2011, FGCO and NGC provided notice to the trustee for $158.1 million and $158.9 million, respectively, of PCRBs of their election to terminate applicable supporting LOCs. As a result, these PCRBs are subject to mandatory purchase on September 1, 2011. Subject to market conditions and other considerations, FGCO and NGC currently expect to hold the bonds for future remarketing or refinancing. Also, approximately $28.5 million and $98.9 million aggregate principal amount of FMBs previously delivered to certain of the LOC providers by FGCO and NGC, respectively, will be cancelled in connection with the mandatory purchases.

Regulatory Matters

NYSEG Ruling

On July 11, 2011, FirstEnergy was found to be a potentially responsible party under CERCLA indirectly liable for a portion of past and future clean-up costs at certain legacy MGP sites in New York. As a result, FirstEnergy recognized additional expense of $29 million during the second quarter of 2011; $30 million had previously been reserved prior to 2011.

Marginal transmission loss recovery

On March 3, 2010, the PPUC issued an order denying Met-Ed and Penelec the ability to recover marginal transmission losses through the transmission service charge riders in their respective tariffs which applies to the periods including June 1, 2008 through December 31, 2010. Subsequently, Met-Ed and Penelec filed a Petition for Review with the Commonwealth Court of Pennsylvania (Commonwealth Court) appealing the PPUC s order. On June 14, 2011, the Commonwealth Court affirmed the PPUC s decision that marginal transmission losses are not recoverable as transmission costs. On July 13, 2011, Met-Ed and Penelec filed a federal complaint with the United States District Court for the Eastern District of Pennsylvania and on the following day, filed a Petition for Allowance of Appeal to the Pennsylvania Supreme Court. Met-Ed and Penelec believe the Commonwealth Court s decision contradicts federal law and is inconsistent with prior PPUC and court decisions and therefore expect to fully recover the related regulatory assets ($189 million for Met-Ed and $65 million for Penelec). In January 2011 and continuing for 29 months, pursuant to a related PPUC order, Met-Ed and Penelec began crediting customers for the amounts at issue pending outcome of the court appeals.

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 used 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, Maryland, New Jersey and New York, and purchases power for its POLR, SOS and default service requirements in Ohio, Pennsylvania, New Jersey and Maryland. 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, SOS 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 investment 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 previously dedicated to MISO were integrated into the PJM market. All of FirstEnergy s assets now reside in 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 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 (prior to June 1, 2011) to deliver energy to the segment s customers.

The Other and Reconciling Adjustments segment contains corporate items and other businesses that are below the quantifiable threshold for separate disclosure as a reportable segment as well as reconciling adjustments for the elimination of intersegment transactions.

RESULTS OF OPERATIONS

The financial results discussed below include revenues and expenses from transactions among FirstEnergy s business segments. Results from the pre-merged companies have been segregated from the Allegheny companies for variance reporting and analysis. A reconciliation of segment financial results is provided in Note 13 to the consolidated financial statements. Earnings available to FirstEnergy by business segment were as follows:

	Three Months Ended June 30			Six Months Ended June 30		
	2011	**2010**	**Increase (Decrease)**	**2011**	**2010**	**Increase (Decrease)**
	(In millions, except per share data)					
Earnings (Loss) By Business Segment:						
Regulated Distribution	$ 184	$ 132	$ 52	$ 280	$ 235	$ 45
Competitive Energy Services	12	121	(109)	17	190	(173)
Regulated Independent Transmission	31	11	20	44	23	21
Other and reconciling adjustments*	(46)	1	(47)	(110)	(28)	(82)

Earnings available to FirstEnergy Corp.	$ 181	$ 265	$ (84)	$ 231	$ 420	$ (189)
Basic Earnings Per Share	$ 0.43	$ 0.87	$ (0.44)	$ 0.61	$ 1.38	$ (0.77)
Diluted Earnings Per Share	$ 0.43	$ 0.87	$ (0.44)	$ 0.61	$ 1.37	$ (0.76)

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

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

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

Second Quarter 2011 Financial Results	Regulated Distribution	Competitive Energy Services	Regulated Independent Transmission (In millions)	Other and Reconciling Adjustments	FirstEnergy Consolidated
Revenues:					
External					
Electric	$ 2,352	$ 1,394	$	$	$ 3,746
Other	133	101	105	(37)	302
Internal		318		(306)	12
Total Revenues	2,485	1,813	105	(343)	4,060
Expenses:					
Fuel	73	562			635
Purchased power	1,144	382		(306)	1,220
Other operating expenses	438	640	19	8	1,105
Provision for depreciation	153	107	15	7	282
Amortization of regulatory assets	87		3		90
General taxes	180	51	8	3	242
Total Expenses	2,075	1,742	45	(288)	3,574
Operating Income	410	71	60	(55)	486
Other Income (Expense):					
Investment income	27	15		(11)	31
Interest expense	(148)	(79)	(12)	(26)	(265)
Capitalized interest	3	12	1	4	20
Total Other Expense	(118)	(52)	(11)	(33)	(214)
Income Before Income Taxes	292	19	49	(88)	272
Income taxes	108	7	18	(32)	101
Net Income (Loss)	184	12	31	(56)	171
Loss attributable to noncontrolling interest				(10)	(10)
Earnings (loss) available to FirstEnergy Corp.	$ 184	$ 12	$ 31	$ (46)	$ 181

Second Quarter 2010 Financial Results	**Regulated Distribution**	**Competitive Energy Services**	**Regulated Independent Transmission (In millions)**	**Other and Reconciling Adjustments**	**FirstEnergy Consolidated**
Revenues:					
External					
Electric	$ 2,243	$ 739	$	$	$ 2,982
Other	71	56	59	(29)	157
Internal	19	539		(558)	
Total Revenues	2,333	1,334	59	(587)	3,139
Expenses:					
Fuel		350			350
Purchased power	1,291	330		(558)	1,063
Other operating expenses	331	340	16	(14)	673
Provision for depreciation	106	71	10	3	190
Amortization of regulatory assets	158		3		161
General taxes	138	27	7	4	176
Total Expenses	2,024	1,118	36	(565)	2,613
Operating Income	309	216	23	(22)	526
Other Income (Expense):					
Investment income	28	13		(10)	31
Interest expense	(125)	(57)	(6)	(19)	(207)
Capitalized interest	1	24	1	14	40
Total Other Expense	(96)	(20)	(5)	(15)	(136)
Income Before Income Taxes	213	196	18	(37)	390
Income taxes	81	75	7	(29)	134
Net Income (Loss)	132	121	11	(8)	256
Loss attributable to noncontrolling interest				(9)	(9)
Earnings available to FirstEnergy Corp.	$ 132	$ 121	$ 11	$ 1	$ 265

Changes Between Second Quarter 2011 and Second 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	$ 109	$ 655	$	$	$ 764
Other	62	45	46	(8)	145
Internal	(19)	(221)		252	12
Total Revenues	152	479	46	244	921
Expenses:					
Fuel	73	212			285
Purchased power	(147)	52		252	157
Other operating expenses	107	300	3	22	432
Provision for depreciation	47	36	5	4	92
Amortization of regulatory assets	(71)				(71)
General taxes	42	24	1	(1)	66
Total Expenses	51	624	9	277	961
Operating Income	101	(145)	37	(33)	(40)
Other Income (Expense):					
Investment income	(1)	2		(1)	
Interest expense	(23)	(22)	(6)	(7)	(58)
Capitalized interest	2	(12)		(10)	(20)
Total Other Expense	(22)	(32)	(6)	(18)	(78)
Income Before Income Taxes	79	(177)	31	(51)	(118)
Income taxes	27	(68)	11	(3)	(33)
Net Income	52	(109)	20	(48)	(85)
Loss attributable to noncontrolling interest				(1)	(1)
Earnings available to FirstEnergy Corp.	$ 52	$ (109)	$ 20	$ (47)	$ (84)

Regulated Distribution — Second Quarter 2011 Compared with Second Quarter 2010

Net income increased by $52 million in the second quarter of 2011 compared to the second quarter of 2010 primarily due to earnings from the Allegheny companies and increased operating margins from the pre-merger companies as a result of reduced purchased power costs, partially offset by reduced revenues.

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Revenues

The increase in total revenues resulted from the following sources:

Revenues by Type of Service	Three Months Ended June 30 2011	2010	Increase (Decrease)
	(In millions)		
Pre-merger companies:			
Distribution services	$ 810	$ 851	$ (41)
Generation sales:			
Retail	747	1,097	(350)
Wholesale	104	180	(76)
Total generation sales	851	1,277	(426)
Transmission	51	141	(90)
Other	66	64	2
Total pre-merger companies	1,778	2,333	(555)
Allegheny companies	707		707
Total Revenues	$ 2,485	$ 2,333	$ 152

The decrease in distribution service revenues for the pre-merger companies reflects lower transition revenues due to the completion of transition cost recovery for CEI in December 2010, partially offset by increased rates associated with the recovery of deferred distribution costs. Distribution deliveries (excluding the Allegheny companies) decreased by 1.1% in the second quarter of 2011 from the second quarter of 2010. The change 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	8,623	8,663	(0.5)%
Commercial	7,926	8,121	(2.4)%
Industrial	8,798	8,846	(0.5)%
Other	126	132	(4.5)%
Total pre-merger companies	25,473	25,762	(1.1)%
Allegheny companies	9,527		
Total Electric Distribution KWH Deliveries	35,000	25,762	35.9%

Lower deliveries to residential and commercial customers reflected decreased weather-related usage in the second quarter of 2011 as cooling degree days decreased by 17.3% from the same period in 2010, and soft economic conditions affecting the commercial sector. In the industrial sector, KWH deliveries decreased by 4% to automotive

customers, partially offset by increased deliveries to steel and electrical equipment customers of 11% and 15%, respectively.
The following table summarizes the price and volume factors contributing to the $426 million decrease in generation revenues for the pre-merger companies in the second quarter of 2011 compared to the second quarter of 2010:

Source of Change in Generation Revenues	**Increase (Decrease) (In millions)**
Retail:	
Effect of decrease in sales volumes	$ (447)
Change in prices	96
	(351)
Wholesale:	
Effect of decrease in sales volumes	(8)
Change in prices	(67)
	(75)
Net Decrease in Generation Revenues	$ (426)

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The decrease in retail generation sales volume was primarily due to increased customer shopping in service territories of the pre-merger companies in the second quarter of 2011, compared with the second quarter of 2010. Total generation provided by alternative suppliers as a percentage of total KWH deliveries increased to 77% from 61% for the Ohio companies and to 55% from 10% for 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 $90 million due to the termination of Met-Ed s and Penelec s TSC rates 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 $707 million of revenues for the second quarter of 2011, including $155 million for distribution services, $486 million for generation sales and $66 million relating to transmission revenues.

Expenses

Total expenses increased by $51 million due to the following:

Purchased power costs, excluding the Allegheny companies, were $483 million lower in the second quarter of 2011 due primarily to a decrease in volumes required. 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 $336 million in purchased power costs in the second 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	$ (161)
Change due to increased volumes	88
	(73)
Purchases from FES:	
Change due to increased unit costs	20
Change due to decreased volumes	(398)
	(378)
Increase in costs deferred	(32)
Total pre-merger companies	(483)
Purchases by Allegheny companies	336
Net Decrease in Purchased Power Costs	$ (147)

Transmission expenses decreased $29 million primarily due to lower PJM network transmission expenses and congestion costs of $70 million for Met-Ed and Penelec, partially offset by transmission expenses for the Allegheny companies of $41 million in the second 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 by $43 million.
The absence of a $7 million favorable JCP&L labor settlement that occurred in the second quarter of 2010.
Net amortization of regulatory assets decreased $71 million due primarily to reduced transition cost recovery and increased deferral of energy efficiency program costs.
Fuel expenses for MP were $73 million in the second quarter of 2011.

Operating expenses for the Allegheny companies were $95 million in the second quarter of 2011.

Depreciation expense for the Allegheny companies was $48 million in the second quarter of 2011.

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Merger-related costs increased $4 million in the second quarter of 2011 compared to the same period of 2010.

General taxes increased $42 million primarily due to property taxes and gross receipts taxes incurred by the Allegheny companies in the second quarter of 2011.

Other Expense

Other expense increased $22 million in the second quarter of 2011 due to interest expense on debt of the Allegheny companies.

Regulated Independent Transmission Second Quarter 2011 Compared with Second Quarter 2010

Net income increased by $20 million in the second quarter of 2011 compared to the second quarter of 2010 due to earnings associated with TrAIL and PATH ($22 million), partially offset by decreased earnings for ATSI ($1 million).

Revenues

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

Revenues by Transmission Asset Owner	**Three Months Ended June 30 2011**	**2010**	**Increase (Decrease)**
	(In millions)		
ATSI	$ 54	$ 59	$ (5)
TrAIL	46		46
PATH	5		5
Total Revenues	$ 105	$ 59	$ 46

Expenses

Total expenses increased by $9 million principally due to TrAIL and PATH operating expenses.

Other Expense

Other expense increased $6 million in the second quarter of 2011 due to additional interest expense associated with TrAIL.

Competitive Energy Services Second Quarter 2011 Compared with Second Quarter 2010

Net income decreased by $109 million in the second quarter of 2011, compared to the second quarter of 2010, primarily due to reduced sales margins, non-core asset impairments and the effect of mark-to-market adjustments.

Revenues

Total revenues increased by $479 million in the second quarter of 2011 primarily due to growth in direct and governmental 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 June 30 2011	2010	Increase (Decrease)
	(In millions)		
Direct and Governmental Aggregation	$ 925	$ 586	$ 339
POLR and Structured Sales	231	615	(384)
Wholesale	66	77	(11)
Transmission	30	19	11
RECs	12		12
Other	38	37	1
Allegheny Companies	511		511
Total Revenues	$ 1,813	$ 1,334	$ 479

Allegheny Companies	
Direct and Governmental Aggregation	$ 26
POLR and Structured Sales	185
Wholesale	267
Transmission	32
Other	1
Total Revenues	$ 511

MWH Sales by Type of Service	Three Months Ended June 30 2011	2010	Increase (Decrease)
	(In thousands)		
Direct	11,547	7,004	64.9%
Governmental Aggregation	3,970	2,715	46.2%
POLR and Structured Sales	3,718	11,600	(67.9)%
Wholesale	395	1,108	(64.4)%
Allegheny Companies	8,051		
Total Sales	27,681	22,427	23.4%

Allegheny Companies	
Direct	425
POLR	2,169
Structured Sales	846
Wholesale	4,611
Total Sales	8,051

The increase in direct and governmental aggregation revenues of $339 million resulted from the acquisition of new commercial and industrial customers as well as new governmental aggregation contracts with communities in Ohio, providing generation to approximately 1.5 million residential and small commercial customers at the end of June 2011 compared to approximately 1.1 million at the end of June 2010. Partially offsetting the increase, were sales to residential and small commercial customers that were adversely affected by weather in the market served that was 17% cooler than in 2010.

The decrease in POLR revenues of $384 million was due to lower sales volumes to Met-Ed, Penelec and the Ohio Companies, partially offset by increased sales to non-associated companies and higher unit prices to the Pennsylvania Companies consistent with our business strategy. Participation in POLR auctions and RFPs are expected to continue but the proportion of these sales will depend on our hedge positions for direct retail and aggregation sales.

Wholesale revenues decreased $11 million due to reduced generation available for sale in the wholesale market.

The following tables summarize the price and volume factors contributing to changes in revenues (excluding the Allegheny companies):

Source of Change in Direct and Governmental Aggregation	**Increase (Decrease)** *(In millions)*
Direct Sales:	
Effect of increase in sales volumes	$ 267
Change in prices	(13)
	254
Governmental Aggregation:	
Effect of increase in sales volumes	80
Change in prices	5
	85
Net Increase in Direct and Governmental Aggregation Revenues	$ 339

Source of Change in POLR and Structured Revenues	**Increase (Decrease)** *(In millions)*
POLR:	
Effect of decrease in sales volumes	$ (418)
Change in prices	34
	(384)

Source of Change in Wholesale Revenues	**Increase (Decrease)** *(In millions)*
Wholesale:	
Effect of decrease in sales volumes	(49)
Change in prices	38
	(11)

Transmission revenues increased by $11 million due primarily to higher PJM congestion revenue. The revenues derived from the sale of RECs increased $12 million in the second quarter of 2011.

Expenses

Total expenses increased by $624 million in the second quarter of 2011 due to the following:

Fuel costs decreased by $27 million primarily due to decreased volumes ($56 million), partially offset by higher unit prices ($29 million). Volumes decreased due to lower generation at the fossil units. Higher unit prices reflect increased coal transportation costs and higher nuclear fuel unit prices following the refueling outages that occurred in 2010.

Purchased power costs were unchanged as higher unit costs ($70 million) were offset by lower volumes purchased ($70 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.

Fossil operating costs increased by $18 million due primarily to higher labor, contractor and materials and equipment costs due to in increase in outages, both planned and unplanned, from the previous year.

Nuclear operating costs increased by $33 million due primarily to having two refueling outages, Perry and Beaver Valley 2, occurring this year. While Davis-Besse had a refueling outage last year, the work performed during the second quarter of 2010 was largely capital-related.

Transmission expenses increased by $66 million due primarily to increases in PJM of $91 million from higher congestion, network, and line loss expense, partially offset by lower MISO transmission expenses of $25 million due to lower network and line loss costs.

General taxes increased by $10 million due to an increase in revenue-related taxes.

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Other expenses increased by $36 million primarily due to: a $14 million mark-to-market adjustment; a $7 million impairment charge related to non-core assets; and an $8 million increase in intercompany billings. The intercompany billings increased due to merger related costs and increased intersegment billings for leasehold costs from the Ohio Companies.

The inclusion of the Allegheny companies operations contributed $488 million to expenses, including a $9 million mark-to-market adjustment relating primarily to power contracts.

Other Expense

Total other expense in the second quarter of 2011 was $32 million higher than the second quarter of 2010, primarily due to a $34 million increase in net interest expense partially offset by an increase in investment income ($2 million). The increase in interest expense was primarily due to the inclusion of the Allegheny companies ($22 million) and lower capitalized interest ($12 million) associated with the completion of the Sammis AQC project in 2010.

Source of Expense Changes	**Increase (Decrease)** *(In millions)*	
Allegheny Companies		
Fuel	$	238
Purchased power		53
Fossil		55
Transmission		75
Mark-to-Market		9
General taxes		11
Other		15
Depreciation		32
Total Expense	$	488

Other Second Quarter of 2011 Compared with Second 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 $47 million decrease in earnings available to FirstEnergy in the second quarter of 2011 compared to the same period in 2010. The decrease resulted primarily from increased operating expenses resulting from adverse litigation resolution ($29 million), decreased capitalized interest ($10 million) resulting from completed construction projects and increased interest expense due to the 2010 termination of interest rate swap agreements ($7 million).

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Summary of Results of Operations First Six Months of 2011 Compared with the First Six Months of 2010

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

First Six Months 2011 Financial Results	Regulated Distribution	Competitive Energy Services	Regulated Independent Transmission (In millions)	Other and Reconciling Adjustments	FirstEnergy Consolidated
Revenues:					
External					
Electric	$ 4,527	$ 2,556	$	$	$ 7,083
Other	226	180	172	(69)	509
Internal		661		(617)	44
Total Revenues	4,753	3,397	172	(686)	7,636
Expenses:					
Fuel	97	991			1,088
Purchased power	2,323	700		(617)	2,406
Other operating expenses	824	1,288	36	(10)	2,138
Provision for depreciation	269	195	25	13	502
Amortization of regulatory assets	216		6		222
General taxes	356	95	16	12	479
Total Expenses	4,085	3,269	83	(602)	6,835
Operating Income	668	128	89	(84)	801
Other Income (Expense):					
Investment income	52	21		(21)	52
Interest expense	(280)	(144)	(21)	(51)	(496)
Capitalized interest	4	22	1	11	38
Total Other Expense	(224)	(101)	(20)	(61)	(406)
Income Before Income Taxes	444	27	69	(145)	395
Income taxes	164	10	25	(20)	179
Net Income (Loss)	280	17	44	(125)	216
Loss attributable to noncontrolling interest				(15)	(15)
Earnings available to FirstEnergy Corp.	$ 280	$ 17	$ 44	$ (110)	$ 231

First Six Months 2010 Financial Results	Regulated Distribution	Competitive Energy Services	Regulated Independent Transmission	Other and Reconciling Adjustments	FirstEnergy Consolidated

			(In millions)		
Revenues:					
External					
Electric	$ 4,641	$ 1,408	$	$	$ 6,049
Other	157	106	116	(57)	322
Internal	19	1,213		(1,165)	67
Total Revenues	4,817	2,727	116	(1,222)	6,438
Expenses:					
Fuel		684			684
Purchased power	2,686	780		(1,165)	2,301
Other operating expenses	690	692	30	(38)	1,374
Provision for depreciation	210	148	19	6	383
Amortization of regulatory assets	367		6		373
General taxes	292	64	14	11	381
Total Expenses	4,245	2,368	69	(1,186)	5,496
Operating Income	572	359	47	(36)	942
Other Income (Expense):					
Investment income	54	14		(21)	47
Interest expense	(250)	(113)	(11)	(46)	(420)
Capitalized interest	2	47	1	31	81
Total Other Expense	(194)	(52)	(10)	(36)	(292)
Income Before Income Taxes	378	307	37	(72)	650
Income taxes	143	117	14	(29)	245
Net Income (Loss)	235	190	23	(43)	405
Loss attributable to noncontrolling interest				(15)	(15)
Earnings available to FirstEnergy Corp.	$ 235	$ 190	$ 23	$ (28)	$ 420

Changes Between First Six Months 2011 and First Six Months 2010 Financial Results Increase (Decrease)	**Regulated Distribution**	**Competitive Energy Services**	**Regulated Independent Transmission**	**Other and Reconciling Adjustments**	**FirstEnergy Consolidated**
			(In millions)		
Revenues:					
External					
Electric	$ (114)	$ 1,148	$	$	$ 1,034
Other	69	74	56	(12)	187
Internal	(19)	(552)		548	(23)
Total Revenues	(64)	670	56	536	1,198
Expenses:					
Fuel	97	307			404
Purchased power	(363)	(80)		548	105
Other operating expenses	134	596	6	28	764
Provision for depreciation	59	47	6	7	119
Amortization of regulatory assets	(151)				(151)
General taxes	64	31	2	1	98
Total Expenses	(160)	901	14	584	1,339
Operating Income	96	(231)	42	(48)	(141)
Other Income (Expense):					
Investment income	(2)	7			5
Interest expense	(30)	(31)	(10)	(5)	(76)
Capitalized interest	2	(25)		(20)	(43)
Total Other Expense	(30)	(49)	(10)	(25)	(114)
Income Before Income Taxes	66	(280)	32	(73)	(255)
Income taxes	21	(107)	11	9	(66)
Net Income	45	(173)	21	(82)	(189)
Loss attributable to noncontrolling interest					
Earnings available to FirstEnergy Corp.	$ 45	$ (173)	$ 21	$ (82)	$ (189)

Regulated Distribution — First Six Months of 2011 Compared to First Six Months of 2010

Net income increased by $45 million in the first six months of 2011, compared to the first six months of 2010, primarily due to the absence of a $35 million regulatory asset impairment recorded in 2010 and the earnings contribution of the Allegheny companies, partially offset by a favorable property tax settlement recognized in 2010.

Revenues

The decrease in total revenues resulted from the following sources:

Revenues by Type of Service	Six Months Ended June 30 2011	2010	Increase (Decrease)
		(In millions)	
Pre-merger companies:			
Distribution services	$ 1,719	$ 1,733	$ (14)
Generation sales:			
Retail	1,620	2,272	(652)
Wholesale	220	397	(177)
Total generation sales	1,840	2,669	(829)
Transmission	88	299	(211)
Other	123	116	7
Total pre-merger companies	3,770	4,817	(1,047)
Allegheny companies	983		983
Total Revenues	$ 4,753	$ 4,817	$ (64)

The decrease in distribution service revenues for the pre-merger companies primarily reflects lower transition revenues due to the completion of transition cost recovery for CEI in December 2010, partially offset by increased rates associated with the recovery of deferred distribution costs. Distribution deliveries (excluding the Allegheny companies) increased approximately 360,000 KWH (0.7%), primarily driven by an increase of 443,000 KWH (2.6%) in the industrial class. Distribution deliveries by customer class are summarized in the following table:

Electric Distribution KWH Deliveries	**2011**	**2010**	**Increase (Decrease)**
	(in thousands)		
Pre-merger companies:			
Residential	19,261	19,119	0.7%
Commercial	15,855	16,074	(1.4)%
Industrial	17,640	17,197	2.6%
Other	256	262	(2.3)%
Total pre-merger companies	53,012	52,652	0.7%
Allegheny companies	13,068		
Total Electric Distribution KWH Deliveries	66,080	52,652	25.5%

Lower distribution deliveries to commercial customers reflected soft economic conditions in this sector and decreased weather-related usage in the first six months of 2011 as cooling degree days were 17% below the same period in 2010. The increase in distribution deliveries to industrial customers was primarily due to recovering economic conditions in the Utilities service territory compared to the first six months of 2010. Industrial deliveries increased by 12% to steel customers, 16% to electrical equipment and component manufacturing customers and 10% to non-metallic mineral customers, partially offset by 2% lower sales to automotive customers.
The following table summarizes the price and volume factors contributing to the $829 million decrease in generation revenues in the first six months of 2011 compared to the same period of 2010:

Source of Change in Generation Revenues	**Increase (Decrease)**
	(In millions)
Retail:	
Effect of decrease in sales volumes	$ (826)
Change in prices	174
	(652)
Wholesale:	
Effect of decrease in sales volumes	(2)
Change in prices	(175)
	(177)
Net Decrease in Generation Revenues	$ (829)

The decrease in retail generation sales volume was due to increased customer shopping in the Ohio Companies , Met-Ed s and Penelec s service territories in the first six months of 2011 compared to the same period in 2010. Total generation provided by alternative suppliers as a percentage of total KWH deliveries increased to 75% from 57% for the Ohio companies and to 48% from 9% for 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 $211 million due to the termination of Met-Ed s and Penelec s TSC rates 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 $983 million of revenues for the first six months of 2011, including $216 million for distribution services, $676 million from generation sales and $91 million relating to transmission revenues.

Expenses

Total expenses decreased by $160 million due to the following:

Purchased power costs, excluding the Allegheny companies, were $843 million lower in the first six months of 2011 due to a decrease in volumes required. 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 $481 million in purchased power costs in the first six months 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	$ (356)
Change due to increased volumes	277
	(79)
Purchases from FES:	
Change due to increased unit costs	63
Change due to decreased volumes	(809)
	(746)
Increase in costs deferred	(18)
Total pre-merger companies	(843)
Purchases by Allegheny companies	481
Net Decrease in Purchased Power Costs	$ (362)

Transmission expenses decreased $124 million primarily due to lower PJM network transmission expenses and congestion costs of $177 million for Met-Ed and Penelec, partially offset by transmission expenses for the Allegheny companies of $53 million in the first six months 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 $62 million.

The absence of a $7 million favorable JCP&L labor settlement that occurred in the second quarter of 2010.

A provision for excess and obsolete material of $13 million was recognized in the first six months of 2011 due to revised inventory practices adopted in conjunction with the Allegheny merger.

Net amortization of regulatory assets decreased $150 million primarily due to reduced net PJM transmission cost and transition cost recovery and the absence of a $35 million regulatory asset impairment recognized in 2010 associated with the filing of the Ohio ESP on March 23, 2010, partially offset by increased energy efficiency cost recovery.

Fuel expenses for MP were $97 million in the first six months of 2011.

Operating expenses for the Allegheny companies were $131 million in the first six months of 2011.

Merger-related costs increased $46 million in the first six months of 2011 compared to the same period of 2010.

Depreciation expense for the Allegheny companies was $64 million.

General taxes increased by $64 million primarily due to taxes incurred by the Allegheny companies and the absence of a favorable property tax settlement recognized in 2010.

Other Expense

Other expense increased by $30 million in the first six months of 2011 due to interest expense on debt of the Allegheny companies.

Regulated Independent Transmission First Six Months 2011 Compared with First Six Months 2010

Net income increased by $21 million in the first six months of 2011 compared to the first six months of 2010 due to earnings associated with TrAIL and PATH ($27 million), partially offset by decreased earnings for ATSI ($6 million).

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

Revenues by Transmission Asset Owner	**Six Months Ended June 30 2011**	**2010**	**Increase (Decrease)**
		(In millions)	
ATSI	$ 106	$ 116	$ (10)
TrAIL	61		61
PATH	5		5
Total Revenues	$ 172	$ 116	$ 56

Expenses
Total expenses increased by $14 million principally due to TrAIL and PATH operating expenses.
Other Expense
Other expense increased $10 million in the first six months of 2011 due to interest expense associated with TrAIL.
Competitive Energy Services First Six Months of 2011 Compared to First Six Months of 2010
Net income decreased by $173 million in the first six months of 2011, compared to the first six months of 2010, primarily due to lower sales margin, an inventory reserve adjustment, non-core asset impairments and the effect of mark-to-market adjustments.
Revenues
Total revenues increased $670 million in the first six months of 2011 primarily due to growth in direct and governmental aggregation sales and the inclusion of the Allegheny companies, partially offset by a decline in POLR sales.
The increase in total revenues resulted from the following sources:

Revenues by Type of Service	**Six Months Ended June 30 2011**	**2010**	**Increase (Decrease)**
		(In millions)	
Direct and Governmental Aggregation	$ 1,765	$ 1,097	$ 668
POLR and Structured Sales	607	1,315	(708)
Wholesale	156	142	14
Transmission	56	36	20
RECs	44	67	(23)
Other	79	70	9
Allegheny Companies	690		690
Total Revenues	$ 3,397	$ 2,727	$ 670
Allegheny Companies			
Direct and Governmental Aggregation	$ 34		
POLR and Structured Sales	254		
Wholesale	357		
Transmission	44		
Other	1		

Total Revenues	$	690

MWH Sales by Type of Service	Six Months Ended June 30 2011	2010	Increase (Decrease)
	(In thousands)		
Direct	21,219	12,857	65.0%
Governmental Aggregation	8,279	5,447	52.0%
POLR and Structured Sales	9,561	25,344	(62.3)%
Wholesale	1,380	1,538	(10.3)%
Allegheny Companies	10,687		
Total Sales	51,126	45,186	13.1%

Allegheny Companies	
Direct	570
POLR	2,981
Structured Sales	1,149
Wholesale	5,987
Total Sales	10,687

The increase in direct and governmental aggregation revenues of $668 million resulted from increased revenue from the acquisition of new commercial and industrial customers as well as new governmental aggregation contracts with communities in Ohio that provided generation to approximately 1.5 million residential and small commercial customers at the end of June 2011 compared to approximately 1.1 million customers at the end of June 2010.

The decrease in POLR revenues of $708 million was due to lower sales volumes to Met-Ed, Penelec and the Ohio Companies, partially offset by increased sales to non-associated companies and higher unit prices to the Pennsylvania Companies consistent with our business strategy. Participation in POLR auctions and RFPs are expected to continue but the proportion of these sales will depend on our hedge positions for our direct retail and aggregation sales.

Wholesale revenues increased by $14 million due to higher wholesale prices partially offset by decreased volumes. The lower sales volumes were the result of decreased short-term (net hourly positions) transactions in MISO. Additional capacity revenues earned by units moved to PJM were partially offset by losses on financially settled sales.

The following tables summarize the price and volume factors contributing to changes in revenues (excluding the Allegheny companies):

Source of Change in Direct and Governmental Aggregation	Increase (Decrease)
	(In millions)
Direct Sales:	
Effect of increase in sales volumes	$ 493
Change in prices	(20)
	473
Governmental Aggregation:	
Effect of increase in sales volumes	176
Change in prices	19

		195
Net Increase in Direct and Governmental Aggregation Revenues	$	668

Source of Change in POLR Revenues	**Increase (Decrease)** *(In millions)*
POLR:	
Effect of decrease in sales volumes	$ (819)
Change in prices	111
	(708)

Source of Change in Wholesale Revenues	**Increase (Decrease)**
Wholesale:	
Effect of decrease in sales volumes	(15)
Change in prices	29
	14

Transmission revenues increased by $20 million due primarily to higher MISO and PJM congestion revenue. The revenues derived from the sale of RECs declined $23 million in the first six months of 2011.

Expenses

Total expenses increased by $901 million in the first six months of 2011 due to the following:

- Fuel costs decreased by $13 million primarily due to decreased volumes ($28 million), partially offset by higher unit prices ($15 million). Volumes decreased due to lower generation from the fossil units. Unit prices increased primarily due to increased coal transportation costs and higher nuclear fuel unit prices following the refueling outages that occurred in 2010.
- Purchased power costs decreased by $154 million due primarily to lower volumes purchased ($248 million) partially offset by higher unit costs ($94 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.
- Fossil operating costs increased by $20 million due primarily to higher labor, contractor and material costs resulting from an increase in planned and unplanned outages.
- Nuclear operating costs increased by $48 million due primarily to having two refueling outages, Perry and Beaver Valley 2, occurring this year. While Davis-Besse had a refueling outage last year, the work performed during the second quarter of 2010 was largely capital-related.
- Transmission expenses increased by $176 million due primarily to increases in PJM of $198 million from higher congestion, network, and line loss expense, partially offset by lower MISO transmission expenses of $22 million.
- General taxes increased by $12 million due to an increase in revenue-related taxes.
- Other expenses increased by $93 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 $20 million impairment charge related to non-core assets; and a $9 million increase in intercompany billings. The intercompany billings increased due to merger related costs and increased intersegment billings for leasehold costs from the Ohio Companies.

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The inclusion of the Allegheny companies operations contributed $719 million to expenses, including a $43 million mark-to-market adjustment relating primarily to power contracts.

Source of Expense Changes	Increase (Decrease) (In millions)
Allegheny Companies	
Fuel	$ 320
Purchased power	74
Fossil	82
Transmission	99
Mark-to-Market	43
General taxes	15
Other	43
Depreciation	43
Total Expense	$ 719

Other Expense

Total other expense in the first six months of 2011 was $49 million higher than the first six months of 2010, primarily due to a $56 million increase in net interest expense, partially offset by an increase in nuclear decommissioning trust investment income ($7 million). The increase in interest expense was primarily due to the inclusion of the Allegheny companies ($30 million) and lower capitalized interest ($25 million) associated with the completion of the Sammis AQC project in 2010.

Other First Six Months of 2011 Compared to First Six Months 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 an $82 million decrease in earnings available to FirstEnergy in the first six months of 2011 compared to the same period in 2010. The decrease resulted primarily from increased operating expenses resulting from adverse litigation resolution ($29 million), decreased capitalized interest and increased depreciation expense resulting from completed construction projects placed into service ($27 million), an asset impairment charge in the first quarter of 2011 ($12 million) and increased income taxes ($9 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 June 30, 2011 and December 31, 2010 and changes during the six months then ended:

Regulatory Assets	June 30, 2011	December 31, 2010	Increase (Decrease)
		(In millions)	
OE	$ 393	$ 400	$ (7)
CEI	320	370	(50)
TE	89	72	17
JCP&L	469	513	(44)
Met-Ed	341	296	45
Penelec	222	163	59
Other*	348	12	336

Total	$ 2,182	$ 1,826	$ 356

* 2011 includes $337 million related to the Allegheny companies.

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The following tables provide information about the composition of net regulatory assets as of June 30, 2011 and December 31, 2010 and the changes during the six months then ended:

Regulatory Assets by Source	June 30, 2011	December 31, 2010	Increase (Decrease)	Amount of Increase (Decrease) Attributable to AE
		(In millions)		
Regulatory transition costs	$ 899	$ 770	$ 129	$
Customer receivables for future income taxes	502	326	176	160
Loss on reacquired debt	53	48	5	8
Employee postretirement benefits	11	16	(5)	
Nuclear decommissioning and spent fuel disposal costs	(201)	(184)	(17)	
Asset removal costs	(228)	(237)	9	22
MISO/PJM transmission costs	292	184	108	76
Deferred generation costs	454	386	68	15
Distribution costs	284	426	(142)	
Other	116	91	25	56
Total	$ 2,182	$ 1,826	$ 356	$ 337

FirstEnergy had $385 million of net regulatory liabilities as of June 30, 2011, including $376 million of net regulatory liabilities acquired as part of the merger with AE that are primarily related to customer receivables for future income taxes and asset removal costs.

Regulatory assets that do not earn a current return totaled approximately $345 million as of June 30, 2011, of which $138 million relates to purchase accounting fair value adjustments to corresponding liabilities that do not accrue interest.

Regulatory assets not earning a current return for Met-Ed and Penelec include certain regulatory transition costs and PJM transmission costs of approximately $144 million and $34 million, respectively. The regulatory transition costs are expected to be recovered by 2020.

Regulatory assets not earning a current return for JCP&L include certain storm damage costs and pension and postretirement benefits of approximately $34 million that are expected to be recovered by 2014.

Regulatory assets not earning a current return for FirstEnergy s other utility subsidiaries include certain deferred generation and other costs of approximately $133 million that are expected to be recovered though 2026.

CAPITAL RESOURCES AND LIQUIDITY

As of June 30, 2011, FirstEnergy had $476 million of cash and cash equivalents available to fund investments, operations and capital expenditures. In addition to internal sources to fund liquidity and capital requirements for 2011 and beyond, FirstEnergy may rely on 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. FirstEnergy 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 strategy stresses financial discipline and a strong focus on execution. Major elements include the expectation of: adequate 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.

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As of June 30, 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 June 30, 2011, included the following (in millions):

Currently Payable Long-term Debt		
PCRBs supported by bank LOCs [(1)]	$	949
AE Supply unsecured note		503
FirstEnergy Corp. unsecured note		250
FGCO and NGC unsecured PCRBs [(1)]		136
WP unsecured note		80
NGC collateralized lease obligation bonds		59
Sinking fund requirements		50
Other notes		31
	$	2,058

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

Credit Facility Borrowings and Liquidity

FirstEnergy had approximately $656 million and $700 million of short-term borrowings as of June 30, 2011 and December 31, 2010, respectively. FirstEnergy s available liquidity as of July 29, 2011, is summarized in the following table:

Company	**Type**	**Maturity**		**Commitment**		**Available Liquidity**
				(In millions)		
FirstEnergy[(1)]	Revolving	June 2016	$	2,000	$	1,751
FES / AE Supply	Revolving	June 2016		2,500		2,449
TrAIL	Revolving	Jan. 2013		450		450
AGC	Revolving	Dec. 2013		50		
		Subtotal	$	5,000	$	4,650
		Cash				586
		Total	$	5,000	$	5,236

(1) FirstEnergy Corp. and regulated subsidiary borrowers.

During March 2011, the accounts receivable financing arrangements for OE, TE, Penelec and Met-Ed were terminated in favor of other sources of liquidity that were deemed more economical. In May 2011, AE terminated its $250 million credit facility. AE now participates in the unregulated money pool (see FirstEnergy Money Pools below).

Revolving Credit Facilities

On June 17, 2011, FirstEnergy and certain of its subsidiaries entered into two new five-year syndicated revolving credit facilities with aggregate commitments of $4.5 billion (New Facilities).

An aggregate amount of $2 billion is available to be borrowed under a syndicated revolving credit facility (New FirstEnergy Facility), subject to separate borrowing sublimits for each borrower. The borrowers under the New FirstEnergy Facility are FirstEnergy, CEI, Met-Ed, OE, Penn, TE, ATSI, JCP&L, MP, Penelec, PE and WP. An additional $2.5 billion is available to be borrowed by FES and AE Supply under a separate syndicated revolving credit

facility (New FES/AESupply Facility).
The New Facilities replaced a FirstEnergy $2.75 billion revolving credit facility, an AE Supply $1 billion revolving credit facility, a MP $110 million revolving credit facility, a PE $150 million revolving credit facility and a WP $200 million revolving credit facility, all of which were terminated as of June 17, 2011. Initial borrowings under the New Facilities were used to pay off outstanding obligations under these prior revolving credit facilities.
Commitments under each of the New Facilities will be available until June 17, 2016, unless the lenders agree, at the request of the applicable borrowers, to up to two additional one-year extensions. Generally, borrowings under each of the New Facilities are available to each borrower separately and will mature on the earlier of 364 days from the date of borrowing or the commitment termination date, as the same may be extended.
Borrowings under each of the New Facilities are subject to acceleration upon the occurrence of events of default that each borrower considers usual and customary, including a cross-default for other indebtedness in excess of $100 million. Defaults by either FES or AE Supply or their respective subsidiaries under the New FES/AESupply Facility or other indebtedness generally will not cross-default to FirstEnergy under the New FirstEnergy Facility.

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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 June 30, 2011:

Borrower	**New Revolving Credit Facility Sub-Limit**	**Regulatory and Other Short-Term Debt Limitations**
	(In millions)	
FirstEnergy	$ 2,000	(a)
FES	$ 1,500	(b)
AE Supply	$ 1,000	(b)
OE	$ 500	$ 500
CEI	$ 500	$ 500
TE	$ 500	$ 500
JCP&L	$ 425	$ 411(c)
Met-Ed	$ 300	$ 300(c)
Penelec	$ 300	$ 300(c)
West Penn	$ 200	$ 200(c)
MP	$ 150	$ 150(c)
PE	$ 150	$ 150(c)
ATSI	$ 100	$ 100
Penn	$ 50	$ 33(c)

(a) No limitations.

(b) No limitation based upon blanket financing authorization from the FERC under existing open market tariffs.

(c) Excluding amounts which may be borrowed under the regulated companies money pool.

The entire amount of the New FES/AE Supply Facility and $700 million of the New FirstEnergy Facility, subject to each borrower s sub-limit, is available for 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 each of the New Facilities and against the applicable borrower s borrowing sub-limit.

Each of the New Facilities 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 June 30, 2011, FirstEnergy s and its subsidiaries debt to total capitalization ratios (as defined under each of the New Facilities) were as follows:

Borrower	
FirstEnergy	56.9%
FES	54.1%
OE	56.2%
Penn	34.4%
CEI	56.3%
TE	58.4%
JCP&L	43.9%
Met-Ed	53.5%
Penelec	55.5%

ATSI	54.9%
MP	59.3%
PE	60.1%
WP	53.9%
AE Supply	39.4%

As of June 30, 2011, FirstEnergy could issue additional debt of approximately $7.8 billion, or recognize a reduction in equity of approximately $4.2 billion, and remain within the limitations of the financial covenants required by its credit facility.

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The New Facilities do 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 facilities are related to the credit ratings of the company borrowing the funds.

In addition to the New Facilities, FirstEnergy also has access to an additional $500 million of revolving credit facilities relating to the Allegheny companies (TrAIL $450 million and AGC $50 million).

Under the terms of its credit facility, outstanding debt of AGC may not exceed 65% of the sum of its 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 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 six months of 2011 was 0.43% per annum for the regulated companies money pool and 0.46% per annum for the unregulated companies money pool. FirstEnergy and its regulated companies acquired in the Allegheny merger have filed with the appropriate regulatory commissions to receive approval to become part of the FirstEnergy regulated money pool.

Pollution Control Revenue Bonds

As of June 30, 2011, FirstEnergy s currently payable long-term debt included approximately $949 million (FES $875 million, Met-Ed $29 million and Penelec $45 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 June 30, 2011:

LOC Bank	Aggregate LOC Amount[1] *(In millions)*	LOC Termination Date	Reimbursements of LOC Draws Due
UBS	$ 272	April 2014	April 2014
The Bank of Nova Scotia	178	Beginning June 2012	Multiple dates[2]
CitiBank N.A.	165	June 2014	June 2014
Wachovia Bank	153	March 2014	March 2014
The Royal Bank of Scotland	131	June 2012	6 months
US Bank	60	April 2014	6 months
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 million 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 were cancelled on May 31, 2011.

On April 29, Met-Ed redeemed $14 million of PCRBs at par value.

On June 1, 2011, FGCO repurchased $40 million of PCRBs and, subject to market conditions and other considerations, is holding those bonds for future remarketing or refinancing.

On July 29, 2011, FGCO and NGC provided notice to the trustee for $158.1 million and $158.9 million, respectively, of PCRBs of their election to terminate applicable supporting LOCs. As a result, these PCRBs are subject to mandatory purchase on September 1, 2011. Subject to market conditions and other considerations, FGCO and NGC currently expect to hold the bonds for future remarketing or refinancing. Also, approximately $28.5 million and $98.9 million aggregate principal amount of FMBs previously delivered to certain of the LOC providers by FGCO and NGC, respectively, will be cancelled in connection with the mandatory purchases.

Long-Term Debt Capacity

As of June 30, 2011, the Ohio Companies and Penn had the aggregate capability to issue approximately $2.5 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 $100 million and $19 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 $363 million and $365 million, respectively, under provisions of their senior note indentures as of June 30, 2011. In addition, based upon their respective FMB indentures, net earnings and available bondable property additions as of June 30, 2011, MP, PE and WP had the capability to issue approximately $1.0 billion of additional FMBs in the aggregate.

Based upon FGCO s net earnings and available bondable property additions under its FMB indentures as of June 30, 2011, FGCO had the capability to issue $2.5 billion of additional FMBs under the terms of that indenture. Due to the sale of Fremont Energy Center on July 28, 2011, FGCO s capability to issue additional FMBs was reduced by $510 million. Based upon NGC s net earnings and available bondable property additions under its FMB indenture as of June 30, 2011, NGC had the capability to issue $1.7 billion of additional FMBs as of June 30, 2011 under the terms of that indenture.

FirstEnergy s access to capital markets and costs of financing are influenced by the ratings of its securities. 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. On March 1, 2011, Fitch affirmed the ratings and outlook of FirstEnergy and its subsidiaries. The following table displays FirstEnergy s and its subsidiaries securities ratings as of July 29, 2011.

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

OE	BBB	A3	BBB+	BBB-	Baa2	BBB
Penelec	BBB	A3	BBB+	BBB-	Baa2	BBB
Penn	BBB+	A3	BBB+			
PE	BBB+	Baa1	A-	BBB-	Baa3	BBB+
TE	BBB	Baa1	BBB			
TrAIL				BBB-	Baa2	A-
WP	BBB+	A3	A-	BBB-	Baa2	BBB+

Changes in Cash Position

As of June 30, 2011, FirstEnergy had $476 million of cash and cash equivalents compared to approximately $1 billion as of December 31, 2010. As of June 30, 2011 and December 31, 2010, FirstEnergy had approximately $78 million and $13 million, respectively, of restricted cash included in other current assets on the Consolidated Balance Sheet.

During the first six months of 2011, FirstEnergy received $1.4 billion from cash dividends and equity repurchases by its subsidiaries and paid $420 million in cash dividends to common shareholders, including $20 million paid in March by AE 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, energy delivery services and regulated independent transmission businesses (see Results of Operations above). Net cash provided from operating activities increased by $173 million during the first six months of 2011 compared to the same period in 2010, as summarized in the following table:

Operating Cash Flows	**Six Months Ended June 30 2011**	**2010**	**Increase (Decrease)**
		(In millions)	
Net income	$ 216	$ 405	$ (189)
Non-cash charges	1,229	789	440
Pension trust contribution	(262)		(262)
Working capital and other	(152)	(336)	184
	$ 1,031	$ 858	$ 173

The increase in non-cash charges and other adjustments is primarily due to increased deferred taxes and investment tax credits driven by bonus depreciation and the 2011 pension contribution ($393 million) and increased depreciation from the acquired Allegheny Companies ($119 million), partially offset by lower amortization of regulatory assets from reduced net PJM transmission cost and transition cost recovery ($151 million).

The increase in cash flows from working capital and other is primarily due to decreased receivables from higher customer collections ($355 million) and decreased materials and supplies from the inventory valuation adjustment in the first quarter of 2011 ($41 million), partially offset by increased prepayments and other current assets driven by higher prepaid taxes ($187 million).

Cash Flows From Financing Activities

In the first six months of 2011, cash used for financing activities was $1,039 million compared to $484 million in the comparable period of 2010. The following table summarizes new debt financing (net of any discounts) and redemptions:

Debt Issuances and Redemptions	**Six Months Ended June 30 2011**	**2010**
	(In millions)	
New Issues		
Pollution control notes	$ 272	$
Long-term revolving credit	70	
Unsecured Notes	161	
	$ 503	$
Redemptions		
Pollution control notes	$ 312	$ 251
Long-term revolving credit	475	
Senior secured notes	166	55

First mortgage bonds		14		
Unsecured notes		35		100
	$	1,002	$	406
Short-term borrowings, net	$	(44)	$	281

In 2011, FES paid off at maturity a $100 million term loan that was secured by FMBs. In April 2011, FirstEnergy entered into a $150 million unsecured term loan with an April 2013 maturity.

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In 2011 FES repurchased and retired $20 million of its 6.80% unsecured senior notes and $15 million of its 6.05% unsecured senior notes. In April 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 through redemptions, open market or privately negotiated purchases. Any such transactions will be subject to prevailing market conditions, liquidity requirements, timing of asset sales and other factors.

Cash Flows From Investing Activities

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

Summary of Cash Flows Provided from (Used for) Investing Activities	**Property Additions**	**Investments**	**Other**	**Total**
		(In millions)		
Sources (Uses)				
Six Months Ended June 30, 2011				
Regulated distribution	$ (479)	$ (2)	$ (25)	$ (506)
Competitive energy services	(411)	(32)	(335)	(778)
Regulated independent transmission	(72)	(1)	(1)	(74)
Cash received in Allegheny merger		590		590
Other and reconciling items	(56)	(21)	310	233
Total	$ (1,018)	$ 534	$ (51)	$ (535)
Six Months Ended June 30, 2010				
Regulated distribution	$ (309)	$ 87	$ (18)	$ (240)
Competitive energy services	(619)	(11)	(1)	(631)
Regulated independent transmission	(29)		(2)	(31)
Other and reconciling items	(40)	(25)		(65)
Total	$ (997)	$ 51	$ (21)	$ (967)

Net cash used in investing activities during the first six months of 2011 decreased by $432 million compared to the same period of 2010. The decrease was principally due to cash acquired in the Allegheny merger ($590 million), partially offset by a decrease in net proceeds from asset sales and higher property additions ($137 million).

During the second half of 2011, capital requirements for property additions and capital leases are expected to be approximately $1.2 billion, including approximately $122 million for nuclear fuel.

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 June 30, 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)]	$	223
OVEC obligations		300
Other[(2)]		301
		824
Subsidiaries Guarantees		
Energy and Energy-Related Contracts		155
FES guarantee of NGC s nuclear property insurance		70
FES guarantee of FGCO s sale and leaseback obligations		2,324
Other		19
		2,568
Surety Bonds		136
LOC[(3)]		269
		405
Total Guarantees and Other Assurances	$	3,797

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

(2) Includes guarantees of $95 million for nuclear decommissioning funding assurances, $161 million supporting OE s sale and leaseback arrangement, and $35 million for railcar leases.

(3) Includes $105 million issued for various terms pursuant to LOC capacity available under FirstEnergy s revolving credit facilities, $122 million pledged in connection with the sale and leaseback of Beaver Valley Unit 2 by OE and $39 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 other FirstEnergy 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 an LOC or accelerated payments may be required of the subsidiary. As of June 30, 2011, FirstEnergy s maximum exposure under these collateral provisions was $625 million, as shown below:

Collateral Provisions	**FES**	**AE Supply**	**Utilities**	**Total**
		(In millions)		
Credit rating downgrade to below investment grade (1)	$ 440	$ 4	$ 78	$ 522
Material adverse event (2)	33	57	13	103
Total	$ 473	$ 61	$ 91	$ 625

(1) Includes $206 million and $59 million that is also considered an acceleration of payment or funding obligation for FES and the Utilities, respectively.

(2) Includes $32 million that is also considered an acceleration of payment or funding obligation for 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 $666 million, as shown below:

Collateral Provisions	FES	AE Supply	Utilities	Total
		(In millions)		
Credit rating downgrade to below investment grade (1)	$ 477	$ 5	$ 78	$ 560
Material adverse event (2)	36	57	13	106
Total	$ 513	$ 62	$ 91	$ 666

(1) Includes $206 million and $59 million that is also considered an acceleration of payment or funding obligation for FES and the Utilities, respectively.

(2) Includes $32 million that is also considered an acceleration of payment or funding obligation for FES.

Most of FirstEnergy s surety bonds are backed by various indemnities common within the insurance industry. Surety bonds and related guarantees of $136 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 portfolios as of June 30, 2011 and forward prices as of that date, FES and AE Supply have posted collateral of $138 million and $2 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 $17 million of collateral. Depending on the volume of forward contracts and future price movements, higher amounts for margining could be required to be posted.

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 would 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 due in October 2012. 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, was $1.6 billion as of June 30, 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 5 to the consolidated financial statements). Sources of information for the valuation of commodity derivative contracts as of June 30, 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]	(287)	(169)	(48)	(38)			(542)
Prices based on models	9	(3)				44	50
Total[3]	$ (278)	$ (172)	$ (48)	$ (38)	$	$ 44	$ (492)

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

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

(3) Includes $445 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 June 30, 2011, an adverse 10% change in commodity prices would decrease net income by approximately $31 million ($20 million net of tax) during the next 12 months.

Equity Price Risk

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.

The benefit plan assets and obligations are remeasured annually using a December 31 measurement date or as significant triggering events occur. As of June 30, 2011, the FirstEnergy pension plan was invested in approximately 31% of equity securities, 46% of fixed income securities, 9% of absolute return strategies, 6% of real estate, 4% of private equity and 4% of cash. 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 three months and six months ended June 30, 2011, FirstEnergy made contributions to its qualified pension plans of $105 million and $262 million, respectively. FirstEnergy intends to make additional contributions of $116 million and $2 million to its qualified pension plans and postretirement benefit plans, respectively, in the last two quarters of 2011.

NDT funds have been established to satisfy NGC s and the Utilities nuclear decommissioning obligations. As of June 30, 2011, approximately 87% of the funds were invested in fixed income securities, 10% of the funds were invested in equity securities and 3% 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 $1,779 million, $197 million and $69 million for fixed income securities, equity securities and short-term investments, respectively, as of June 30, 2011, excluding $6 million of receivables, payables, deferred taxes and accrued income. A hypothetical 10% decrease in prices quoted by stock exchanges would result in a $20 million reduction in fair value as of June 30, 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 NDT as other-than-temporary impairments. A decline in the value of FirstEnergy s NDT or a significant escalation in estimated decommissioning costs could result in additional funding requirements. During the first six months of 2011, approximately $1 million, $4 million and $1 million was contributed to NDT of JCP&L, OE and TE, respectively. 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 $92 million. On June 24, 2011, FENOC submitted a $95 million parental guarantee to the NRC for its approval.

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 June 30, 2011, the largest credit concentration was with J.P. Morgan Chase & Co., which is currently rated investment grade, representing 11% of FirstEnergy s total approved credit risk comprised of 2.4% for FES, 1.6% for JCP&L, 2.0% for Met-Ed, 3.4% for WP and a combined 2.0% for the Ohio Companies.

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, ATSI and TrAIL. The NERC is the ERO 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 FERC will continue to refine existing reliability standards as well as to develop and adopt new reliability standards. The financial impact of complying with future 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 future 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, although a final determination has not yet been made by FERC.

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 investigations with regard to certain matters of compliance by Allegheny.

Maryland

By statute enacted in 2007, the obligation of Maryland utilities to provide standard offer service (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. PE now conducts rolling auctions to procure the power supply necessary to serve its customer load pursuant to a plan approved by the MDPSC. 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 electric consumption be reduced by 10% and electricity demand be reduced by 15%, in each case by 2015.

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. 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. 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 and those programs are to be filed by September 1, 2011.

In March 2009, the MDPSC 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. 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. The Maryland legislature passed a bill on April 11, 2011, which 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 legislation directs the MDPSC to consider cost-effectiveness, and provides that the MDPSC 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, with proposed rules to be filed by September 15, 2011. Separately, on April 7, 2011, the MDPSC initiated a rulemaking with respect to issues related to contact voltage. On June 3, 2011, the MDPSC s Staff issued a report and draft regulations. Comments on the draft regulations were submitted on June 17, 2011, and a hearing was held July 7, 2011. Final regulations related to contact voltage have not yet been adopted.

New Jersey

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). In its order of June 15, 2011, the NJBPU adopted a Stipulation reached among JCP&L, the NJBPU Staff and the Division of Rate Counsel which resolved both Petitions, resulting in a net reduction in recovery of $0.8 million annually for all components of the SBC (including, as requested, a zero level of recovery of TMI-2 decommissioning costs).

Ohio

The Ohio Companies operate under an ESP, which expires on May 31, 2014. The material terms of the ESP include: generation supplied through a CBP commencing June 1, 2011 (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 (FES is one of the wholesale suppliers to the Ohio Companies); 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. The Ohio Companies also agreed not to recover from retail customers certain costs related to transmission cost allocations by PJM as a result of ATSI s 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.

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 were 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. OE fell short of its statutory 2010 energy efficiency and peak demand reduction benchmarks and 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. The PUCO granted this request on May 19, 2011 for OE, finding that the motion was moot for CEI and TE. 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 them into compliance with their yet-to-be-defined modified benchmarks. On June 2, 2011, the Companies filed an application for rehearing to clarify the decision related to CEI and TE. 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. On May 4, 2011, the PUCO granted applications for rehearing for the purpose of further consideration; however, no substantive ruling has been issued.

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 and 0.50% of the KWH they served in 2010. In August and October 2009, the Ohio Companies conducted RFPs to secure RECs. 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 and 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. 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. Other parties to the proceeding filed comments asserting that the force majeure determination should not be granted, and others requesting the PUCO to review the costs the Ohio companies have incurred to comply with the renewable energy requirements. 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 PUCO modified and approved the companies application on May 25, 2011, ruling that the new credit be phased out over an eight-year period and granting authority for the companies to recover deferred costs and associated carrying charges. OCC filed applications for rehearing on June 24, 2011 and the Ohio Companies filed their responses on July 5, 2011. The PUCO has not yet acted on the applications for rehearing.

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. Pursuant to the plan approved by the PPUC, Met-Ed and Penelec began to refund those amounts to customers in January 2011, and the refunds will continue over a 29 month period until the full amounts previously recovered for marginal transmission loses are refunded. 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. On June 14, 2011, the Commonwealth Court issued an opinion and order affirming the PPUC s Order to the extent that it holds that line loss costs are not transmission costs and, therefore, the approximately $254 million in marginal transmission losses and associated carrying charges for the period prior to January 1, 2011, are not recoverable under Met-Ed s and Penelec s TSC riders. Met-Ed and Penelec filed a Petition for Allowance of Appeal with the Pennsylvania Supreme Court and also a complaint seeking relief in federal district court. Although the ultimate outcome of this matter cannot be determined at this time, Met-Ed and Penelec believe that they should ultimately prevail through the judicial process and therefore expect to fully recover the approximately $254 million ($189 million for Met-Ed and $65 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.

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. On February 18, 2011, the companies filed a petition to approve their First Amended EE&C Plans. On June 28, 2011, a hearing on the petition was held before an administrative law judge.

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 Met-Ed, Penelec and Penn 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 Met-Ed, Penelec and Penn, 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. 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, 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 OCA 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. One party retained the ability to challenge the recovery of amounts spent on WP s original smart meter implementation plan. 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. On May 3, 2011, the ALJ issued an Initial Decision recommending that the PPUC approve the Amended Joint Petition for Full Settlement. The PPUC approved the Initial Decision by order entered June 30, 2011.

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. On April 29, 2011, the PPUC entered an Order initiating the investigation and requesting comments from interested parties on eleven directed questions. Met-Ed, Penelec, Penn Power and West Penn submitted joint comments on June 3, 2011. FES also submitted comments on June 3, 2011. On June 8, 2011, the PPUC conducted an en banc hearing on these issues at which both the Pennsylvania Companies and FES participated and offered testimony.

Virginia

In September 2010, PATH-VA filed an application with the VSCC for authorization to construct the Virginia portions of the PATH Project. On February 28, 2011, PATH-VA filed a motion to withdraw the application. On May 24, 2011, the VSCC granted PATH-VA s motion to withdraw its application for authorization to construct the Virginia portions of the PATH Project. 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, which was amended through subsequent filings. MP and PE ultimately requested an annual increase in retail rates of approximately $95 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. A hearing was held at the WVPSC on June 13, 2011. An order is expected by late September 2011.

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 and 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 and Morgantown Energy Associates, each the owner of one of the contracted resources, has participated in the case in opposition to the Petition.

FERC Matters

Rates for Transmission Service Between MISO and PJM

In November 2004, FERC issued an order eliminating the through and out rate for transmission service between the MISO and PJM regions. 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, 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 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 FERC in November 2010, and the relevant payments made. The subsidiaries of Allegheny entered into nine settlements to fix their liability for SECA charges with various parties. All of the settlements were approved by FERC and the relevant payments have been made for eight of the settlements. Payments due under the remaining settlement will be made as a part of the refund obligations of the Utilities that are under review by FERC as part of a compliance filing. Potential refund obligations of FirstEnergy and the Allegheny subsidiaries 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.

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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 a paper hearing meaning that FERC called for parties to submit written comments 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 FERC.

RTO Realignment

On June 1, 2011, ATSI and the ATSI zone entered into PJM. The move was performed as planned with no known operational or reliability issues for ATSI or for the wholesale transmission customers in the ATSI zone.

On February 1, 2011, ATSI in conjunction with PJM filed its proposal with FERC for moving its transmission rate into PJM s tariffs. 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 amendments to 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.

On May 31, 2011, FERC issued orders that address the proposed ATSI transmission rate, and certain parts of the MISO tariffs that reflect the mechanics of transmission cost allocation and collection. In its May 31, 2011 orders, FERC approved ATSI s proposal to move the ATSI formula rate into the PJM tariff without significant change. Speaking to ATSI s proposed treatment of the MISO s exit fees and charges for transmission costs that were allocated to the ATSI zone, FERC required ATSI to present a cost-benefit study that demonstrates that the benefits of the move for transmission customers exceed the costs of any such move, which FERC had not previously required. Accordingly, FERC ruled that these costs must be removed from ATSI s proposed transmission rates until such time as ATSI files and FERC approves the cost-benefit study. On June 30, 2011, ATSI submitted the compliance filing that removed the MISO exit fees and transmission cost allocation charges from ATSI s proposed transmission rates. Also on June 30, 2011, ATSI requested rehearing of FERC s decision to require a cost-benefit study analysis as part of FERC s evaluation of ATSI s proposed transmission rates. The compliance filing, and ATSI s request for rehearing, are currently pending before FERC.

From late April 2011 through June 2011, FERC issued other orders that address ATSI s move into PJM. These orders approve ATSI s proposed interconnection agreements for large wholesale transmission customers and generators, and revisions to the PJM and MISO tariffs that reflect ATSI s move into PJM. In addition, FERC approved an Exit Fee Agreement that memorializes the agreement between ATSI and MISO with regard to ATSI s obligation to pay certain administrative charges to the MISO upon exit. Finally, ATSI and the MISO were able to negotiate an agreement of ATSI s responsibility for certain charges associated with long term firm transmission rights that, according to the MISO, were payable by the ATSI zone upon its departure from the MISO. ATSI did not and does not agree that these costs should be charged to ATSI but, in order to settle the case and all claims associated with the case, ATSI agreed to a one-time payment of $1.8 million to the MISO. This settlement agreement has been submitted for FERC s review and approval. The final outcome of those proceedings that address the remaining open issues related to ATSI s move into PJM and their impact, if any, on FirstEnergy cannot be predicted at this time.

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 transmission projects that are approved via MISO s formal transmission planning process (the MTEP). 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 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 MVPs 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 that had been made 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 attached 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.

As noted above, on February 1, 2011, ATSI filed proposed transmission rates related to its move into PJM. The proposed rates included line items that were intended to recover all MVP costs (if any) that might be charged to ATSI or to the ATSI zone. In its May 31, 2011 order on ATSI s proposed transmission rates FERC ruled that ATSI must submit a cost-benefit study before ATSI can recover the MVP costs. FERC further directed that ATSI remove the line-items from ATSI s formula rate that would recover the MVP costs until such time as ATSI submits and FERC approves the cost-benefit study. ATSI requested a rehearing of these parts of FERC s order and, pending this further legal process, has removed the MVP line items from its transmission rates.

FirstEnergy cannot predict the outcome of these proceedings at this time.

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 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 FERC, which arises out of claims previously filed with 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 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. On May 4, 2011, FERC affirmed the judge s ruling.

In June 2009, the California Attorney General, on behalf of certain California parties, filed a second complaint with 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 including AE Supply in this new complaint. AE Supply filed a motion to dismiss the Brown complaint that was granted by FERC on May 24, 2011. On June 23, 2011, the California Attorney General requested rehearing of the May 24, 2011 order. FirstEnergy cannot predict the outcome of this matter.

Transmission Expansion

TrAIL Project. TrAIL is a 500 kV transmission line extending from southwest Pennsylvania through West Virginia and into northern Virginia. Effective May 19, 2011, all segments of TrAIL were energized and in service.

PATH Project. The PATH Project is comprised of a 765 kV transmission line that was 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.

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PJM initially authorized construction of the PATH Project in June 2007. 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 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. The WVPSC and VSCC have granted the motions 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.

Seneca Pumped Storage Project Relicensing

The Seneca (Kinzua) Pumped Storage Project is a 451 MW hydroelectric project located in Warren County, Pennsylvania owned and operated by FGCO. FGCO holds the current FERC license that authorizes ownership and operation of the project. The current FERC license will expire on November 30, 2015. FERC s regulations call for a five-year relicensing process. On November 24, 2010, and acting pursuant to applicable FERC regulations and rules, FGCO initiated the relicensing process by filing its notice of intent to relicense and pre-application document (PAD) in the license docket.

On November 30, 2010, the Seneca Nation of Indians filed its notice of intent to relicense and PAD documents necessary for them to submit a competing application. Section 15 of the FPA contemplates that third parties may file a competing application to assume ownership and operation of a hydroelectric facility upon (i) relicensure and (ii) payment of net book value of the plant to the original owner/operator. Nonetheless, FGCO believes it is entitled to a statutory incumbent preference under Section 15.

The Seneca Nation and certain other intervenors have asked FERC to redefine the project boundary of the hydroelectric plant to include the dam and reservoir facilities operated by the U.S. Army Corps. of Engineers. On May 16, 2011, FirstEnergy filed a Petition for Declaratory Order with FERC seeking an order to exclude the dam and reservoir facilities from the project. The Seneca Nation, the New York State Department of Environmental Conservation, and the U.S. Department of Interior each submitted responses to FirstEnergy s petition, including motions to dismiss FirstEnergy s petition. The project boundary issue is pending before FERC.

The next steps in the relicensing process are for FirstEnergy and the Seneca Nation to define and perform certain environmental and operational studies to support their respective applications. These steps are expected to run through approximately November of 2013. FirstEnergy cannot predict the outcome of these proceedings at this time.

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.

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 coal-fired 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 coal-fired plant based on modifications dating back to 1986. On March 31, 2011, the EPA proposed emissions limits and compliance schedules to reduce SO2 air emissions by approximately 81% at the Portland Plant based on an interstate pollution transport petition submitted by New Jersey under Section 126 of the CAA. The NOV also alleged NSR violations at the Keystone and Shawville coal-fired plants based on modifications dating back to 1984. Met-Ed, JCP&L, as the former owner of 16.67% of Keystone, and Penelec, as former owner and operator of Shawville, 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 coal-fired Homer City Plant 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 Homer City containing in all material respects allegations identical to those included in the June 2008 NOV. 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 Homer City 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 Homer City, 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 Homer City s air emissions as well as certification as a class action and to enjoin Homer City 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 Homer City seeking injunctive relief and civil penalties. Mission is seeking indemnification from Penelec, the co-owner and operator of Homer City prior to its sale in 1999. On April 21, 2011, Penelec and all other defendants filed Motions to Dismiss all of the federal claims and the various state claims. Responsive and Reply briefs were filed on May 26, 2011 and June 17, 2011, respectively. 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 coal-fired 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 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 Eastlake Plant. In June 2011, EPA issued another Finding of Violation and NOV alleging violations of the CAA and Ohio regulations, specifically opacity limitations and requirements to continuously operate opacity monitoring systems at the Eastlake, Lakeshore, Bay Shore and Ashtabula coal-fired plants. Also, in June 2011, FirstEnergy received an information request pursuant to section 114(a) of the CAA for certain operating maintenance and planning information, among other information regarding these plants. 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 an information request pursuant to section 114(a) of the CAA letter from the EPA requesting that it provide information and documentation relevant to the operation and maintenance of the following ten coal-fired plants, which collectively include 22 electric generation units Albright, Armstrong, Fort Martin, Harrison, Hatfield s Ferry, Mitchell, Pleasants, Rivesville, R. Paul Smith and Willow Island 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 plants: 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 coal-fired plants 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 Plants in Pennsylvania. On January 17, 2006, the PA DEP and the Attorneys General filed an amended complaint. A 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 Plants in Pennsylvania and the Fort Martin and Willow Island coal-fired plants 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 coal-fired plant for NO_X, SO_2 and mercury, based on a PJM declaration that the plant 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 coal-fired plant. 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 SO2 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 2011, the EPA finalized the Cross-State Air Pollution Rule (CSAPR) to replace CAIR, which remains in effect until CSAPR becomes effective (60 days after publication in the Federal Register). CSAPR requires reductions of NOx and SO2 emissions in two phases (2012 and 2014), ultimately capping SO2 emissions in affected states to 2.4 million tons annually and NOx emissions to 1.2 million tons annually. CSAPR allows trading of NOx and SO_2 emission allowances between power plants located in the same state and interstate trading of NOx and SO_2 emission allowances with some restrictions. FGCO s future cost of compliance may be substantial and changes to FirstEnergy s operations may result. Management is currently assessing the impact of CSAPR, other environmental proposals and other factors on FirstEnergy s competitive fossil generating facilities, including but not limited to, the impact on value of our emissions allowances (currently reflected at $38 million on our Consolidated Balance Sheet as of June 30, 2011) and the operations of its coal-fired plants.

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 (CO2) 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. On June 20, 2011, the U. S. Supreme Court reversed the Second Circuit. The Court remanded to the Second Circuit the issue of whether the CAA preempted state common law nuisance actions. The Court s ruling also failed to answer the question of the extent to which actions for damages may remain viable. While FirstEnergy is not a party to this litigation, in June 2011, FirstEnergy received notice of a complaint alleging that the GHG emissions of 87 companies, including FirstEnergy, render them liable for damages to certain residents of Mississippi stemming from Hurricane Katrina. On July 27, 2011, the plaintiff voluntarily dismissed FirstEnergy from this complaint.

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.

In 2004, the EPA established new performance standards under Section 316(b) of the Clean Water Act for reducing impacts on fish and shellfish from cooling water intake structures at certain existing 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). In 2007, the Court of Appeals for the Second Circuit invalidated portions of the Section 316(b) performance standards and 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. On July 19, 2011, the EPA extended the public comment period for the new proposed Section 316(b) regulation by 30 days but stated its schedule for issuing a final rule remains July 27, 2012. 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 coal-fired Bay Shore 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.

In May 2011, the West Virginia Highlands Conservancy, the West Virginia Rivers Coalition, and the Sierra Club filed a CWA citizen suit alleging violations of arsenic limits in the NPDES water discharge permit for the fly ash disposal site at the Albright coal-fired plant seeking unspecified civil penalties and injunctive relief. MP is currently seeking relief from the arsenic limits through WVDEP agency review. In June 2011, the West Virginia Highlands Conservancy, the West Virginia Rivers Coalition, and the Sierra Club served another 60-Day Notice of Intent required prior to filing a citizen suit under the Clean Water Act for alleged failure to obtain a permit to construct the fly ash impoundments at the Albright Station.

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

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 coal-fired plant. 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 in September 2011, however the Court stayed all prehearing deadlines on July 15, 2011 to allow the parties additional time to work out a settlement. 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. In May 2011, the EPA agreed with PA DEP s recommended sulfate impairment designation. PA DEP s goal is to submit a final water quality standards regulation, incorporating the sulfate impairment designation for EPA approval by May, 2013. PA DEP will then need to develop a TMDL limit for the river, a process that will take approximately 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.

The Little Blue Run (LBR) Coal Combustion By-products (CCB) impoundment is expected to run out of disposal capacity for disposal of CCBs from the Bruce Mansfield Plant between 2016 and 2018. In July 2011, BMP submitted a Phase I permit application to PA DEP for construction of a new dry CCB disposal facility adjacent to LBR. BMP anticipates submitting zoning applications for approval to allow construction of a new dry CCB disposal facility prior to commencing construction.

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 June 30, 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 $133 million (JCP&L $69 million, TE $1 million, CEI $1 million, FGCO $1 million and FirstEnergy $61 million) have been accrued through June 30, 2011. Included in the total are accrued liabilities of approximately $63 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. On July 11, 2011, FirstEnergy was found to be a potentially responsible party under CERCLA indirectly liable for a portion of past and future clean-up costs at certain legacy MGP sites, estimated to total approximately $59 million. FirstEnergy recognized additional expense of $29 million during the second quarter of 2011; $30 million had previously been reserved prior to 2011.

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 yet to take 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 June 30, 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. As required by the NRC, FirstEnergy annually recalculates and adjusts the amount of its parental guarantee, as appropriate. The values of FirstEnergy s NDT 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 NDT. The NRC issued guidance anticipating an increase in low-level radioactive waste disposal costs associated with the decommissioning of 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. On June 24, 2011, FENOC submitted a $95 million parental guarantee to the NRC for its approval.

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, a 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 challenging whether FENOC s Environmental Report adequately evaluated (1) a combination of renewable energy sources as alternatives to the renewal of Davis-Besse s operating license, and (2) severe accident mitigation alternatives at Davis-Besse. On May 6, 2011, FENOC filed an appeal with the NRC Commissioners from the order granting a hearing on the Davis-Besse license renewal application.

On April 14, 2011, a group of environmental organizations petitioned the NRC Commissioners to suspend certain pending nuclear licensing proceedings, including the Davis-Besse license renewal proceeding, to ensure that any safety and environmental implications of the accident at the Fukushima Daiichi Nuclear Power Station in Japan are considered. By May 2, 2011, the NRC Staff, FENOC and much of the nuclear industry filed responses opposing the petition. On May 6, 2011, petitioners filed a supplemental reply.

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.

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 entered into a long term Coal Sales Agreement with AE Supply and MP for the supply of coal to the Harrison generating facility. 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 from January 10, 2011 through February 1, 2011. At trial, AE Supply and MP presented evidence that they have incurred in excess of $80 million in damages for replacement coal purchased through the end of 2010 and will incur additional damages in excess of $150 million for future shortfalls. 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 ($90 million in future damages and $14 million for replacement coal / interest). Post-trial filings occurred in May 2011, with Oral Argument on June 28, 2011. The parties expect a ruling sometime in the third quarter, at which time the judgment will be final. The parties have 30 days to appeal the final judgment. AE Supply and MP intend to vigorously pursue this matter through appeal if necessary but cannot predict its outcome.

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.

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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 governmental aggregation programs, and 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

Net income decreased by $158 million in the first six months of 2011 compared to the same period of 2010. The decrease was primarily due to lower sales margin, an inventory reserve adjustment, non-core asset impairments and the effect of mark-to-market adjustments.

Revenues

Total revenues decreased $30 million, or 1%, in the first six months of 2011, compared to the same period of 2010, primarily due to reduced POLR and structured sales, partially offset by growth in direct and governmental aggregation sales.

The decrease in revenues resulted from the following sources:

Revenues by Type of Service	Six Months Ended June 30 2011	2010	Increase (Decrease)
	(In millions)		
Direct and Governmental Aggregation	$ 1,765	$ 1,097	$ 668
POLR and Structured Sales	607	1,315	(708)
Wholesale	156	142	14
Transmission	56	36	20
RECs	44	67	(23)
Other	56	57	(1)
Total Revenues	**$ 2,684**	**$ 2,714**	**$ (30)**

MWH Sales by Type of Service	Six Months Ended June 30 2011	2010	Increase (Decrease)
	(In thousands)		
Direct	21,219	12,857	65.0%
Governmental Aggregation	8,279	5,447	52.0%

POLR and Structured Sales	9,561	25,344	(62.3)%
Wholesale	1,380	1,538	(10.3)%
Total Sales	**40,439**	**45,186**	**(10.5)**%

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The increase in direct and governmental aggregation revenues of $668 million resulted from the acquisition of new commercial and industrial customers as well as new governmental aggregation contracts with communities in Ohio that provided generation to approximately 1.5 million residential and small commercial customers at the end of June 2011 compared to approximately 1.1 million customers at the end of June 2010.

The decrease in POLR revenues of $708 million was due to lower sales volumes to Met-Ed and Penelec, primarily due to the absence in 2011 of a 1,300 MW third-party contract associated with serving Met-Ed and Penelec, and reduced sales to the Ohio Companies, partially offset by increased sales to non-associated companies and higher unit prices to the Pennsylvania Companies consistent with our business strategy. Participation in POLR auctions and RFPs are expected to continue but the proportion of these sales will depend on our hedge positions for direct retail and aggregation sales.

Wholesale revenues increased by $14 million due to higher wholesale prices partially offset by decreased volumes. The lower sales volumes were the result of decreased short-term (net hourly positions) transactions in MISO. Additional capacity revenues earned by generating units were partially offset by losses on financially settled sales.

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

Source of Change in Direct and Governmental Aggregation	**Increase (Decrease)** *(In millions)*
Direct Sales:	
Effect of increase in sales volumes	$ 493
Change in prices	(20)
	473
Governmental Aggregation:	
Effect of increase in sales volumes	176
Change in prices	19
	195
Net Increase in Direct and Governmental Aggregation Revenues	$ 668

Source of Change in POLR Revenues	**Increase (Decrease)** *(In millions)*
POLR:	
Effect of decrease in sales volumes	$ (819)
Change in prices	111
	$ (708)

Source of Change in Wholesale Revenues	**Increase (Decrease)**
Wholesale:	
Effect of increase in sales volumes	$ (15)
Change in prices	29

$	14

Transmission revenues increased by $20 million due primarily to higher MISO and PJM congestion revenue. The revenues derived from the sale of RECs declined $23 million in the first six months of 2011.

Expenses

Total operating expenses increased by $199 million in the first six 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 six 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 increased unit costs	$ 2
Change due to volume consumed	(29)
	(27)
Nuclear Fuel:	
Change due to increased unit costs	14
Change due to volume consumed	1
	15
Non-affiliated Purchased Power:	
Change due to increased unit costs	108
Change due to volume purchased	(242)
	(134)
Affiliated Purchased Power:	
Change due to increased unit costs	34
Change due to volume purchased	(30)
	4
Net Decrease in Fuel and Purchased Power Costs	**$ (142)**

Total fuel costs decreased by $12 million in the first six months of 2011, compared to the same period of 2010, as a result of reduced generation at the fossil units, partially offset by higher fossil unit costs. Fossil unit prices increased primarily due to 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 by $134 million in the first six months of 2011, compared to the same period of 2010, due 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 in the first half of 2011. Affiliated purchased power costs increased by $4 million in the first six months of 2011, compared to the same period of 2010, due to higher unit costs, partially offset by decreased volumes purchased.

Other operating expenses increased by $302 million in the first six months of 2011, compared to the same period of 2010 due to the following:

Transmission expenses increased by $176 million due primarily to increases in PJM of $198 million from higher congestion, network, and line loss expense, partially offset by lower MISO transmission expenses of $22 million.

- Nuclear operating costs increased by $48 million due primarily to having two refueling outages, Perry and Beaver Valley 2, occurring this year. While Davis-Besse had a refueling outage last year, the work performed during the second quarter of 2010 was largely capital-related.
- Fossil operating costs increased by $20 million due primarily to higher labor, contractor and material costs resulting from an increase in planned and unplanned outages.
- A $54 million provision for excess and obsolete material related to revised inventory practices adopted in connection with the Allegheny merger.

Impairment charges of long-lived assets increased by $18 million due to impairments at certain non-core peaking facilities during the first six months of 2011.

General taxes increased by $11 million due to an increase in revenue-related taxes.

Other Expense

Total other expense increased by $17 million in the first six months of 2011, compared to the same period of 2010, primarily due to a decrease in capitalized interest ($24 million) associated with the completion of the Sammis AQC project in 2010, partially offset by increased investment income ($8 million) from higher NDT income.

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. OE procures 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: Regulatory Assets, 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 $5 million in the first six months of 2011, compared to the same period of 2010. The decrease primarily resulted from lower revenues and higher other operating expenses, partially offset by lower purchased power costs and amortization of regulatory assets.

Revenues

Revenues decreased by $171 million, or 18%, in the first six months of 2011, compared with the same period in 2010, due to a decrease in generation revenues, partially offset by higher distribution and wholesale generation revenues.

Distribution revenues increased by $31 million in the first six months of 2011, compared to the same period in 2010, due to an increase in KWH deliveries in the residential and industrial sectors and higher average prices in all customer classes. The higher KWH deliveries in the residential class were driven by increased weather-related usage in the first six months of 2011, reflecting a 6% increase in heating degree days. The increase in distribution deliveries to industrial customers was primarily due to recovering economic conditions in OE s and Penn s service territory. Higher average prices in all customer classes were principally due to the recovery of deferred distribution costs.

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

Distribution KWH Deliveries	Increase
Residential	3.0%
Commercial	0.2%
Industrial	3.5%
Increase in Distribution Deliveries	**2.4%**

Distribution Revenues	Increase *(In millions)*
Residential	$ 19
Commercial	7
Industrial	5
Increase in Distribution Revenues	**$ 31**

Retail generation revenues decreased by $211 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 purchased power 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 six months of

2011, as described above. The increase in customer shopping for residential, commercial and industrial customer classes was 23%, 14% and 8%, respectively.

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

Retail Generation KWH Sales	**Decrease**
Residential	(30.7)%
Commercial	(39.0)%
Industrial	(25.4)%
Decrease in Retail Generation Sales	**(31.2)%**

Retail Generation Revenues	**Decrease**	
	(In millions)	
Residential	$	(128)
Commercial		(52)
Industrial		(31)
Decrease in Retail Generation Revenues	**$**	**(211)**

Wholesale revenues increased by $15 million in the first six months of 2011, compared to the same period of 2010, due to higher revenues from sales to NGC from OE s leasehold interests in Perry Unit 1 and Beaver Valley Unit 2.

Expenses

Total expenses decreased by $171 million in the first six 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	$	(175)
Other operating expenses		36
Amortization of regulatory assets, net		(36)
General taxes		4
Net Decrease in Expenses	**$**	**(171)**

Purchased power costs decreased in the first six months of 2011, compared to the same period of 2010, due to lower KWH purchases resulting from reduced generation sales requirements in the first six months of 2011 coupled with lower unit costs. The increase in other operating expenses for the first six months of 2011 was principally due to expenses associated with refueling outages at OE s leased Perry and Beaver Valley Unit 2 that were absent in 2010. The amortization of regulatory assets decreased primarily due to higher deferred residential generation credits in 2011. General taxes increased as a result of higher property taxes.

Other Expense

Other expense increased by $3 million in the first six months of 2011, compared to the same period of 2010 due to lower nuclear decommissioning trust investment income.

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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: Regulatory Assets, 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 slightly in the first six months of 2011, compared to the same period of 2010. The decrease in earnings was due to lower revenues, partially offset by lower purchased power and amortization of regulatory assets.

Revenues

Revenues decreased by $183 million, or 29%, in the first six months of 2011, compared to the same period of 2010, due to lower retail generation and distribution revenues.

Distribution revenues decreased by $14 million in the first six months of 2011, compared to the same period of 2010, due to lower average unit prices for the residential and industrial customer classes, partially offset by increased KWH deliveries to the residential and commercial customer classes. The lower average unit prices were the result of the absence of transition charges in 2011. Higher KWH deliveries to the residential class were driven by increased weather-related usage in the first six months of 2011, reflecting a 15% increase in heating degree days in CEI s service territory. Lower distribution deliveries to industrial customers reflected softer economic conditions in this sector.

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

Distribution KWH Deliveries	**Increase (Decrease)**
Residential	2.2%
Commercial	2.9%
Industrial	(3.1)%
Increase in Distribution Deliveries	**0.6%**

Distribution Revenues	**Increase (Decrease)** *(In millions)*
Residential	$ 2
Commercial	17
Industrial	(33)
Net Decrease in Distribution Revenues	**$ (14)**

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Retail generation revenues decreased by $169 million in the first six months of 2011, compared to the same period of 2010, primarily due to lower KWH sales in all customer classes and lower average unit prices for the commercial and residential customer classes. Customer shopping has increased for residential, commercial and industrial classes by 22%, 13% and 36%, respectively. 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 purchased power costs, resulting in no material effect to current period earnings. Reduced KWH sales were primarily the result of increased customer shopping in the first six months of 2011, partially offset by the impact of increased weather-related usage by residential customers as described above. Lower average unit prices in the residential customer class were the result of generation credits in place for 2011.

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

Retail Generation KWH Sales	**Decrease**
Residential	(46.6)%
Commercial	(44.2)%
Industrial	(69.8)%
Decrease in Retail Generation Sales	**(55.0)%**

Retail Generation Revenues	**Decrease**	
	(In millions)	
Residential	$	(69)
Commercial		(46)
Industrial		(54)
Decrease in Retail Generation Revenues	**$**	**(169)**

Expenses

Total expenses decreased by $173 million in the first six 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	$	(155)
Other operating costs		6
Amortization of regulatory assets, net		(34)
General taxes		10
Net Decrease in Expenses	**$**	**(173)**

Purchased power costs decreased in the first six months of 2011 due to lower KWH purchases resulting from reduced sales requirements in the first six months of 2011. Other operating expenses increased principally due to 2011 inventory valuation adjustments. Decreased amortization of regulatory assets was primarily due to the completion of transition cost recovery at the end of 2010 and deferred residential generation credits in 2011, partially offset by increased recovery of deferred distribution costs and the absence in 2011 of renewable energy credit expenses that were deferred in 2010. General taxes increased in the first six months of 2011 due to increased property taxes as compared to the same period of 2010.

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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: Regulatory Assets, 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 increased by $3 million in the first six months of 2011, compared to the same period of 2010. The increase primarily resulted from lower purchased power costs and higher cost deferrals, partially offset by lower revenues and higher other operating expenses.

Revenues

Revenues decreased by $40 million, or 16%, in the first six 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 by $3 million in the first six months of 2011, compared to the same period of 2010, due to higher residential revenues, partially offset by lower industrial revenues. Residential revenues were the result of higher KWH deliveries and average unit prices. The higher KWH deliveries in the residential class were driven by increased weather-related usage in the first six months of 2011, reflecting a 14% increase in heating degree days, partially offset by a 23% decrease in cooling degree days in TE s service territory. Industrial revenues were impacted by lower average unit prices, partially offset by higher KWH deliveries from recovering economic conditions.

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

Distribution KWH Deliveries	**Increase (Decrease)**
Residential	4.5%
Commercial	(2.5)%
Industrial	3.7%
Net Increase in Distribution Deliveries	**2.6%**

Distribution Revenues	**Increase (Decrease)** *(In millions)*
Residential	$ 5
Commercial	
Industrial	(2)
Net Increase in Distribution Revenues	**$ 3**

Retail generation revenues decreased by $53 million in the first six months of 2011, compared to the same period of 2010, due to lower KWH sales and lower unit prices for all customer classes. 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 purchased power 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 as described above. Customer shopping has increased for residential, commercial and industrial classes by 16%, 13% and 5%, respectively.

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

Retail Generation KWH Sales	**Decrease**
Residential	(28.3)%
Commercial	(46.6)%
Industrial	(11.7)%
Decrease in Retail Generation Sales	**(22.6)%**

Retail Generation Revenues	**Decrease**
	(In millions)
Residential	$ (16)
Commercial	(13)
Industrial	(24)
Decrease in Retail Generation Revenues	**$ (53)**

Wholesale revenues increased by $9 million in the first six 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 by $42 million in the first six 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	$ (53)
Other operating expenses	18
Deferral of regulatory assets, net	(8)
General Taxes	1
Net Decrease in Expenses	**$ (42)**

Purchased power costs decreased in the first six months of 2011, compared to the same period of 2010, due to lower KWH purchases resulting from reduced generation sales requirements in the first six months of 2011 coupled with lower unit costs. The increase in other operating costs for the first six months of 2011 was primarily due to expenses associated with the 2011 refueling outage at the leased Beaver Valley Unit 2 and an Ohio Supreme Court decision rendered in the second quarter of 2011 favoring a large industrial customer, both of which were absent in 2010. The deferral of regulatory assets reduced expenses due to higher PUCO-approved cost deferrals in the first six months of 2011, compared to the same period of 2010.

Other Expense

Other expense increased by $2 million in the first six months of 2011, compared to the same period of 2010, due to lower nuclear decommissioning trust investment income.

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.

As authorized by JCP&L s Board of Directors, on May 31, 2011 JCP&L returned $500 million of capital to FirstEnergy Corp., the sole owner of all of the shares of JCP&L s common stock.

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: Regulatory Assets, Capital Resources and Liquidity, Market Risk Information, Credit Risk, Outlook and New Accounting Standards and Interpretations.

Results of Operations

Net income decreased by $18 million in the first six months of 2011, compared to the same period of 2010. The decrease was primarily due to lower revenues, partially offset by reductions in purchased power costs, other operating costs and net amortization of regulatory assets.

Revenues

Revenues decreased by $190 million, or 13%, in the first six months of 2011 compared to the same period of 2010. The decrease in revenues was due to lower distribution and retail generation revenues, partially offset by an increase in wholesale generation and other revenues.

Distribution revenues decreased by $71 million in the first six months of 2011, compared to the same period of 2010, primarily due to an NJBPU-approved rate adjustment that became effective March 1, 2011, for all customer classes. The lower KWH deliveries to the residential class were influenced by decreased weather-related usage in the first six months of 2011, reflecting a 16% decrease in cooling degree days offsetting a 7% increase in heating degree days in JCP&L s service territory. Lower distribution deliveries to commercial and industrial customers reflected soft economic conditions in these sectors.

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

Distribution KWH Deliveries	**Decrease**
Residential	(2.5)%
Commercial	(3.3)%
Industrial	(1.8)%
Decrease in Distribution Deliveries	**(2.7)%**

Distribution Revenues	**Decrease** *(In millions)*
Residential	$ (33)
Commercial	(31)
Industrial	(7)
Decrease in Distribution Revenues	**$ (71)**

Retail generation revenues decreased by $132 million due to lower retail generation KWH sales in all customer classes primarily due to an increase in customer shopping. Customer shopping has increased for residential, commercial and industrial classes by 10%, 11% and 4%, respectively. 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 purchased power costs, resulting in no material effect to current period earnings.

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

Retail Generation KWH Sales	Decrease
Residential	(12.1)%
Commercial	(26.2)%
Industrial	(24.8)%
Decrease in Retail Generation Sales	**(16.7)%**

Retail Generation Revenues	Decrease *(In millions)*
Residential	$ (68)
Commercial	(59)
Industrial	(5)
Decrease in Retail Generation Revenues	**$ (132)**

Wholesale generation revenues increased by $6 million in the first six months of 2011, compared to the same period of 2010, due to an increase in PJM spot market energy sales.

Other revenues increased by $8 million in the first six months of 2011, compared to the same period of 2010, primarily due to increases in PJM network transmission revenues and transition bond revenues.

Expenses

Total expenses decreased by $163 million in the first six 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	$ (126)
Other operating costs	(6)
Provision for depreciation	(3)
Amortization of regulatory assets, net	(29)
General taxes	1
Net Decrease in Expenses	**$ (163)**

Purchased power costs decreased by $126 million in the first six months of 2011 due to lower requirements from reduced retail generation sales. Other operating costs decreased by $6 million in the first six months of 2011 principally from lower storm restoration costs. The amortization of regulatory assets decreased by $29 million due to reduced cost recovery under the NJBPU-approved NUG tariffs that became effective March 1, 2011, partially offset by lower storm cost deferrals and the write-off of nonrecoverable NUG costs.

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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. 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 returned $150 million of capital to FirstEnergy Corp. on May 31, 2011, the sole owner of all of the shares of Met-Ed s common stock.

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: Regulatory Assets, Capital Resources and Liquidity, Guarantees and Other Assurances, Market Risk Information, Credit Risk, Outlook and New Accounting Standards and Interpretations.

Results of Operations

Net income increased by $10 million in the first six 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 by $279 million, or 30%, in the first six months of 2011 compared to the same period of 2010, reflecting lower distribution, retail generation, wholesale generation and transmission revenues.

Distribution revenues decreased by $154 million in the first six 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. Slightly higher KWH deliveries reflect increased weather-related usage due to an 8% increase in heating degree days offsetting a 15% decrease in cooling degree days in the first six months of 2011, compared to the same period in 2010.

Changes in distribution KWH deliveries and revenues in the first six 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	(4.1)%
Industrial	3.6%
Net Increase in Distribution Deliveries	**0.5%**

Distribution Revenues	**Decrease**
	(In millions)
Residential	$ (58)
Commercial	(47)
Industrial	(49)
Decrease in Distribution Revenues	**$ (154)**

Retail generation revenues decreased by $10 million in the first six months of 2011 compared to the same period of 2010, due to lower KWH sales to all customer classes resulting from increased customer shopping. Customer shopping has increased for residential, commercial and industrial classes by 1%, 42% and 87%, respectively. The impact of increased customer shopping is partially offset by higher generation rates that reflect the inclusion of transmission services under the DSP, effective January 1, 2011, for all customer classes. Retail generation obligations are attributable to non-shopping customers and are procured through full-requirements auctions. In 2011, Met-Ed began deferring the difference between retail generation revenues and purchased power 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 six months of 2011, compared to the same period of 2010, are summarized in the following tables:

Retail Generation KWH Sales	Decrease
Residential	(1.0)%
Commercial	(44.7)%
Industrial	(87.6)%
Decrease in Retail Generation Sales	**(43.1)%**

Retail Generation Revenues	Increase (Decrease) *(In millions)*
Residential	$ 88
Commercial	(14)
Industrial	(84)
Net Decrease in Retail Generation Revenues	**$ (10)**

Wholesale revenues decreased by $105 million in the first six 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 by $11 million in the first six months of 2011 compared to the same period of 2010 primarily due to the termination of Met-Ed s TSC rates effective January 1, 2011. 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 $290 million in the first six 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	$ (149)
Other operating costs	(95)
Provision for depreciation	(1)
Amortization of regulatory assets, net	(43)
General taxes	(2)
Decrease in Expenses	**$ (290)**

Purchased power costs decreased by $149 million in the first six 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 $95 million in the first six months of 2011 compared to the same period in 2010 due to lower transmission congestion and transmission loss expenses that are now included in the cost of purchased power (see reference to deferral accounting above) partially offset by increased costs for energy efficiency programs. The amortization of regulatory assets decreased $43 million in the first six months of 2011 primarily due to the termination of transmission and transition tariff riders at the end of 2010. General taxes decreased by $2 million in the first six months of 2011 primarily due to lower gross receipts taxes.

Other Expense

In the first six months of 2011, interest income decreased by $2 million 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 electric transmission and distribution services. Penelec also procures generation service for those customers electing to retain Penelec as their power supplier. 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: Regulatory Assets, Capital Resources and Liquidity, Guarantees and Other Assurances, Market Risk Information, Credit Risk, Outlook and New Accounting Standards and Interpretations.

Results of Operations

Net income increased by $2 million in the first six 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 and higher net amortization of regulatory assets.

Revenues

Revenues decreased by $193 million, or 25%, in the first six months of 2011 compared to the same period of 2010. The decrease in revenue was primarily due to lower distribution revenues, retail and wholesale generation revenues, and transmission revenues.

Distribution revenues decreased by $5 million in the first six 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, partially offset by a PPUC approved rate adjustment for NUG costs. Higher KWH deliveries to industrial customers were primarily due to recovering economic conditions in Penelec s service territories, compared to the first six months of 2010. Lower KWH deliveries to residential and commercial customers in the first six months of 2011 reflected lower weather-related usage as cooling degree days were 10% below the same period in 2010.

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

Distribution KWH Deliveries	**Increase (Decrease)**
Residential	(1.2)%
Commercial	(4.7)%
Industrial	7.3%
Net Increase in Distribution Deliveries	**1.4%**

Distribution Revenues	**Increase (Decrease)** *(In millions)*
Residential	$ 3
Commercial	(14)
Industrial	6
Net Decrease in Distribution Revenues	**$ (5)**

Retail generation revenues decreased by $80 million in the first six months of 2011, compared to the same period of 2010, due to lower KWH sales for all customer classes resulting from increased customer shopping. The increase in customer shopping for residential, commercial and industrial customer classes was 2%, 45% and 81%, respectively. The impact of customer shopping is partially offset by higher generation rates that reflect the inclusion of transmission services under the DSP, effective January 1, 2011, for all customer classes. Retail generation obligations are attributable to non-shopping customers and are procured through full-requirements auctions. In 2011, Penelec began deferring the difference between retail generation revenues and purchased power 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 six months of 2011, compared to the same period of 2010, are summarized in the following tables:

Retail Generation KWH Sales	Decrease
Residential	(2.7)%
Commercial	(47.1)%
Industrial	(87.4)%
Decrease in Retail Generation Sales	**(47.5)%**

Retail Generation Revenues	Increase (Decrease) *(In millions)*
Residential	$ 52
Commercial	(35)
Industrial	(97)
Net Decrease in Retail Generation Revenues	**$ (80)**

Wholesale generation revenues decreased by $98 million in the first six 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 by $11 million in the first six months of 2011, compared to the same period of 2010, primarily due to the termination of Penelec s TSC rates effective January 1, 2011. 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 $200 million in the first six 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	$ (192)
Other operating costs	(53)
Amortization of regulatory assets, net	46
Provision for depreciation	(1)
Net Decrease in Expenses	**$ (200)**

Purchased power costs decreased by $192 million in the first six months of 2011, compared to the same period of 2010, due to decreased KWH purchased to source generation sales requirements. Other operating costs decreased by $53 million in the first six months of 2011, due to lower transmission congestion and transmission loss expenses that are now included in the cost of purchased power (see reference to deferral accounting above). The amortization of net regulatory assets increased by $46 million in the first six months of 2011, primarily due to reduced NUG deferrals as a result of a PPUC approved increase in Penelec s NUG cost recovery rider in January 2011.

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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

The management of each registrant, with the participation of each registrant s 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 of each registrant have concluded that each respective 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 June 30, 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, FES , OE s, CEI s, TE s, JCP&L s, Met-Ed s and Penelec s internal control o 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.

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PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

Information required for Part II, Item 1 is incorporated by reference to the discussions in Notes 9 and 10 of the Consolidated Financial Statements in Part I, Item 1 of this Form 10-Q.

ITEM 1A. RISK FACTORS

For the quarter ended June 30, 2011, there have been no material changes to the risk factors included in our Annual Report on Form 10-K for the year ended December 31, 2010, as modified by changes to certain risk factors disclosed in our Quarterly Report on Form 10-Q for the period ended March 31, 2011.

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 second quarter of 2011.

	Period			
	April	May	June	Second Quarter
Total Number of Shares Purchased[(a)]	213,550	367,422	428,966	1,009,938
Average Price Paid per Share	$ 38.59	$ 42.62	$ 44.44	$ 42.54
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.

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.

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Signal Peak received the following notices of violation and proposed assessments for the Mine under the Mine Act during the three months ended June 30, 2011:

	Signal Peak
Number of significant and substantial violations of mandatory health or safety standards under 104*	30
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)	8
Number of mining related fatalities	
Total dollar value of proposed assessments	$ 6,989

* 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.

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	Credit Agreement, dated as of June 17, 2011, among FirstEnergy Corp., The Cleveland Electric Illuminating Company, Metropolitan Edison Company, Ohio Edison Company, Pennsylvania Power Company, The Toledo Edison Company, American Transmission Systems, Incorporated, Jersey Central Power & Light Company, Monongahela Power Company, Pennsylvania Electric Company, The Potomac Edison Company and West Penn Power Company, as borrowers, the Royal Bank of Scotland plc, as administrative agent, and the lending banks, fronting banks and swing line lenders identified therein.
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 June 30, 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.

Exhibit Number	
FES	
10.1	Credit Agreement, dated as of June 17, 2011, among FirstEnergy Solutions Corp., and Allegheny Energy Supply Company, LLC, as borrowers, JPMorgan Chase Bank, N.A., as administrative agent, and the lending banks, fronting banks and swing line lenders identified therein.
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 Solutions Corp. for the period ended June 30, 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.
OE	
10.1	Credit Agreement, dated as of June 17, 2011, among FirstEnergy Corp., The Cleveland Electric Illuminating Company, Metropolitan Edison Company, Ohio Edison Company, Pennsylvania Power Company, The Toledo Edison Company, American Transmission Systems, Incorporated, Jersey Central Power & Light Company, Monongahela Power Company, Pennsylvania Electric Company, The Potomac Edison Company and West Penn Power, as borrowers, the Royal Bank of Scotland plc, as administrative agent, and the lending banks, fronting banks and swing line lenders identified therein.
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 Ohio Edison Company. for the period ended June 30, 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.
CEI	
10.1	

	Credit Agreement, dated as of June 17, 2011, among FirstEnergy Corp., The Cleveland Electric Illuminating Company, Metropolitan Edison Company, Ohio Edison Company, Pennsylvania Power Company, The Toledo Edison Company, American Transmission Systems, Incorporated, Jersey Central Power & Light Company, Monongahela Power Company, Pennsylvania Electric Company, The Potomac Edison Company and West Penn Power, as borrowers, the Royal Bank of Scotland plc, as administrative agent, and the lending banks, fronting banks and swing line lenders identified therein.
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 The Cleveland Electric Illuminating Company. for the period ended June 30, 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.

Exhibit Number	
TE	
10.1	Credit Agreement, dated as of June 17, 2011, among FirstEnergy Corp., The Cleveland Electric Illuminating Company, Metropolitan Edison Company, Ohio Edison Company, Pennsylvania Power Company, The Toledo Edison Company, American Transmission Systems, Incorporated, Jersey Central Power & Light Company, Monongahela Power Company, Pennsylvania Electric Company, The Potomac Edison Company and West Penn Power, as borrowers, the Royal Bank of Scotland plc, as administrative agent, and the lending banks, fronting banks and swing line lenders identified therein.
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 The Toledo Edison Company. for the period ended June 30, 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.
JCP&L	
10.1	Credit Agreement, dated as of June 17, 2011, among FirstEnergy Corp., The Cleveland Electric Illuminating Company, Metropolitan Edison Company, Ohio Edison Company, Pennsylvania Power Company, The Toledo Edison Company, American Transmission Systems, Incorporated, Jersey Central Power & Light Company, Monongahela Power Company, Pennsylvania Electric Company, The Potomac Edison Company and West Penn Power, as borrowers, the Royal Bank of Scotland plc, as administrative agent, and the lending banks, fronting banks and swing line lenders identified therein.
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 Jersey Central Power & Light Company. for the period ended June 30, 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.

Met-Ed

10.1	Credit Agreement, dated as of June 17, 2011, among FirstEnergy Corp., The Cleveland Electric Illuminating Company, Metropolitan Edison Company, Ohio Edison Company, Pennsylvania Power Company, The Toledo Edison Company, American Transmission Systems, Incorporated, Jersey Central Power & Light Company, Monongahela Power Company, Pennsylvania Electric Company, The Potomac Edison Company and West Penn Power, as borrowers, the Royal Bank of Scotland plc, as administrative agent, and the lending banks, fronting banks and swing line lenders identified therein.
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

Exhibit Number	
101*	The following materials from the Quarterly Report on Form 10-Q of Metropolitan Edison Company. for the period ended June 30, 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.
Penelec	
10.1	Credit Agreement, dated as of June 17, 2011, among FirstEnergy Corp., The Cleveland Electric Illuminating Company, Metropolitan Edison Company, Ohio Edison Company, Pennsylvania Power Company, The Toledo Edison Company, American Transmission Systems, Incorporated, Jersey Central Power & Light Company, Monongahela Power Company, Pennsylvania Electric Company, The Potomac Edison Company and West Penn Power, as borrowers, the Royal Bank of Scotland plc, as administrative agent, and the lending banks, fronting banks and swing line lenders identified therein.
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 Pennsylvania Electric Company. for the period ended June 30, 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.

* 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.

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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.

August 2, 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

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

JERSEY CENTRAL POWER & LIGHT COMPANY
Registrant

K. Jon Taylor
Controller
(Principal Accounting Officer)