CLEVELAND ELECTRIC ILLUMINATING CO
Form 10-K
February 28, 2012

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D. C. 20549
FORM 10-K
(Mark One)

þ	ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2011
OR

o	TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from to

Commission File Number	Registrant; State of Incorporation; Address; and Telephone Number	I.R.S. Employer Identification No.
333-21011	FIRSTENERGY CORP. (An Ohio Corporation) 76 South Main Street Akron, OH 44308 Telephone (800)736-3402	34-1843785
000-53742	FIRSTENERGY SOLUTIONS CORP. (An Ohio Corporation) c/o FirstEnergy Corp. 76 South Main Street Akron, OH 44308 Telephone (800)736-3402	31-1560186
1-2578	OHIO EDISON COMPANY (An Ohio Corporation) c/o FirstEnergy Corp. 76 South Main Street Akron, OH 44308 Telephone (800)736-3402	34-0437786
1-2323	THE CLEVELAND ELECTRIC ILLUMINATING COMPANY (An Ohio Corporation) c/o FirstEnergy Corp. 76 South Main Street Akron, OH 44308 Telephone (800)736-3402	34-0150020
1-3583	THE TOLEDO EDISON COMPANY (An Ohio Corporation) c/o FirstEnergy Corp. 76 South Main Street Akron, OH 44308 Telephone (800)736-3402	34-4375005

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

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

Registrant	Title of Each Class	Name of Each Exchange on Which Registered
FirstEnergy Corp.	Common Stock, $0.10 par value	New York Stock Exchange

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

Registrant	Title of Each Class
FirstEnergy Solutions Corp.	Common Stock, no par value per share
Ohio Edison Company	Common Stock, no par value per share
The Cleveland Electric Illuminating Company	Common Stock, no par value per share
The Toledo Edison Company	Common Stock, $5.00 par value per share
Jersey Central Power & Light Company	Common Stock, $10.00 par value per share
Metropolitan Edison Company	Common Stock, no par value per share
Pennsylvania Electric Company	Common Stock, $20.00 par value per share

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

Yes þ No o	FirstEnergy Corp.
Yes o No 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

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) 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 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 if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K.

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

and Pennsylvania Electric Company

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See 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

State the aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold, or the average bid and ask price of such common equity, as of the last business day of the registrant’s most recently completed second fiscal quarter.

FirstEnergy Corp., $18,414,746,649 as of June 30, 2011; and for all other registrants, none.

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

CLASS	OUTSTANDING AS OF JANUARY 31, 2012
FirstEnergy Corp., $0.10 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.

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

DOCUMENT	PART OF FORM 10-K INTO WHICH DOCUMENT IS INCORPORATED
Proxy Statement for 2012 Annual Meeting of Stockholders to be held May 15, 2012	Parts II and III

This combined Form 10-K 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.

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 I(1)(a) and (b) of Form 10-K and are therefore filing this Form 10-K with the reduced disclosure format specified in General Instruction I(2) to Form 10-K.

Forward-Looking Statements: This Form 10-K 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-looking 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 before FERC and 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.
- 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 CSAPR which was stayed by the courts on December 30, 2011, and the effects of the EPA's MATS rules.
- The uncertainty of the timing and amounts of the capital expenditures that may arise in connection with any litigation including 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).
- The uncertainty associated with the company's plan to retire its older unscrubbed regulated and competitive fossil units, including the impact on vendor commitments and PJM's review of the company's plans.
- 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).
- Issues that could result from our continuing investigation and analysis of the indications of cracking in the plant shield building at Davis-Besse.
- 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.
- FirstEnergy's ability to improve electric commodity margins and the impact of, among other factors, the increased cost of fuel and fuel 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 NDTs, pension trusts and other trust funds, and cause FirstEnergy and its subsidiaries to make additional contributions sooner, or in

amounts that are larger than currently anticipated.

- The impact of changes to material accounting policies.
- 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 major industrial and commercial customers of FirstEnergy and its subsidiaries.
- Issues concerning the soundness of financial institutions and counterparties with which FirstEnergy and its subsidiaries do business.
- Issues arising from the completed merger of FirstEnergy and AE and the ongoing coordination of their combined operations including FirstEnergy's ability to maintain relationships with customers, employees and suppliers, as well as the ability to continue to successfully integrate the businesses and realize cost savings and other synergies.
- The risks and other factors discussed from time to time in FirstEnergy's and its applicable subsidiaries' SEC filings, and

other similar factors.

Dividends declared from time to time on FE's common stock during any annual period may in the aggregate vary from the indicated amount due to circumstances considered by FE'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 FirstEnergy's 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, except as required by law, any forward-looking statements contained herein as a result of new information, future events or otherwise.

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 subsidiary of AE, which is the parent of TrAIL and has a joint venture in PATH.
AGC	Allegheny Generating Company, a generation subsidiary of AE
Allegheny	Allegheny Energy, Inc., together with its consolidated subsidiaries
ATSI	American Transmission Systems, Incorporated, which owns and operates transmission facilities
Buchanan Energy	Buchanan Energy Company of Virginia, LLC, a subsidiary of AE Supply
CEI	The Cleveland Electric Illuminating Company, an Ohio electric utility operating subsidiary
Centerior	Centerior Energy Corp., former parent of CEI and TE, which merged with OE to form FirstEnergy in 1997
FE	FirstEnergy Corp., a public utility holding company
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., a subsidiary of FES, which owns and operates non-nuclear generating facilities
FirstEnergy	FirstEnergy Corp., together with its consolidated subsidiaries
Global Holding	Global Mining Holding Company, LLC, a joint venture between FEV, WMB Marketing Ventures, LLC and Gunvor Group, Ltd. that owns Global Rail and Signal Peak
Global Rail	A joint venture between FEV, WMB Marketing Ventures, LLC and Gunvor Group, Ltd. 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
Merger Sub	Element Merger Sub, Inc., a Maryland corporation and a wholly owned subsidiary of FirstEnergy
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., a subsidiary of FES, which 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 AEP
PATH-Allegheny	PATH Allegheny Transmission Company, LLC
PATH-VA	PATH Allegheny Virginia Transmission Corporation
PE	The Potomac Edison Company, a Maryland electric utility 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, WMB Marketing Ventures, LLC and Gunvor Group, Ltd. that owns mining operations near Roundup, Montana
TE	The Toledo Edison Company, an Ohio electric utility operating subsidiary
TrAIL	Trans-Allegheny Interstate Line Company, a subsidiary of AET
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
Anker WV	Anker West Virginia Mining Company, Inc.
Anker Coal	Anker Coal Group, Inc.

GLOSSARY OF TERMS, Continued

AOCI	Accumulated Other Comprehensive Income
AEP	American Electric Power Company, Inc.
AMT	Alternative Minimum Tax
AQC	Air Quality Control
ARO	Asset Retirement Obligation
AREPA	Alternative and Renewable Energy Portfolio Act
ARR	Auction Revenue Right
ASLB	Atomic Safety and Licensing Board
BGS	Basic Generation Service
BMP	Bruce Mansfield Plant
CAA	Clean Air Act
CAL	Confirmatory Action Letter
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CATR	Clean Air Transport Rule
CBP	Competitive Bid Process
CCB	Coal Combustion By-products
CDWR	California Department of Water Resources
CERCLA	Comprehensive Environmental Response, Compensation, and Liability Act
CFL	Compact Florescent Light bulb
CFTC	Commodity Futures Trading Commission
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
DCR	Delivery Capital Recovery Rider
DOE	United States Department of Energy
DOJ	United States Department of Justice
DSP	Default Service Plan
Duke	Duke Energy Corporation
EDC	Electric Distribution Company
EDCP	Executive Deferred Compensation Plan
EE&C	Energy Efficiency and Conservation
EGS	Electric Generation Supplier
EMP	Energy Master Plan
ENEC	Expanded Net Energy Cost
EPA	United States Environmental Protection Agency
EPRI	Electric Power Research Institute
ERO	Electric Reliability Organization
ESOP	Employee Stock Ownership Plan
ESP	Electric Security Plan
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
Fitch	Fitch Ratings
FMB	First Mortgage Bond

FPA	Federal Power Act
FTR	Financial Transmission Right
GAAP	Accounting Principles Generally Accepted in the United States
Generation Asset Transfers	Intra-system generation asset transfers from the Ohio Companies and Penn to FGCO and NGC

GLOSSARY OF TERMS, Continued

GHG	Greenhouse Gases
ICG	International Coal Group inc.
ILP	Integrated License Application Process
IRS	Internal Revenue Service
kV	Kilovolt
KWH	Kilowatt-hour
LBR	Little Blue Run
LiDAR	Light Detection and Ranging
LOC	Letter of Credit
LSE	Load Serving Entity
LTIP	Long-Term Incentive Plan
MATS	Mercury and Air Toxics Standards
MDE	Maryland Department of the Environment
MDPSC	Maryland Public Service Commission
Mine Act	Federal Mine Safety and Health Act of 1977
MISO	Midwest Independent Transmission System Operator, Inc.
Mission	Mission Energy Westside, Inc.
Moody’s	Moody’s Investors Service, Inc.
MSHA	Mine Safety and Health Administration
MTEP	MISO Regional Transmission Expansion Plan
MVP	Multi-value Project
MW	Megawatt
MWH	Megawatt-hour
NAAQS	National Ambient Air Quality Standards
NDT	Nuclear Decommissioning Trust
NEIL	Nuclear Electric Insurance Limited
NEPA	National Environmental Policy Act
NERC	North American Electric Reliability Corporation
NJBPU	New Jersey Board of Public Utilities
NNSR	Non-Attainment New Source Review
NOV	Notice of Violation
NOx	Nitrogen Oxide
NPDES	National Pollutant Discharge Elimination System
NRC	Nuclear Regulatory Commission
NSR	New Source Review
NUG	Non-Utility Generation
NYPSC	New York State Public Service Commission
NYSEG	New York State Electric and Gas
OCA	Office of Consumer Advocate (Pennsylvania)
OCI	Other Comprehensive Income
OPEB	Other Post-Employment Benefits
OSBA	Office of Small Business Advocate
OTC	Over The Counter
OTTI	Other Than Temporary Impairments
OVEC	Ohio Valley Electric Corporation
PAD	Pre-application Document
PA DEP	Pennsylvania Department of Environmental Protection

PCB	Polychlorinated Biphenyl
PCRB	Pollution Control Revenue Bond
PJM	PJM Interconnection L. L. C.
PM	Particulate Matter

GLOSSARY OF TERMS, Continued

POLR	Provider of Last Resort
PPUC	Pennsylvania Public Utility Commission
PSA	Power Supply Agreement
PSD	Prevention of Significant Deterioration
PUCO	Public Utilities Commission of Ohio
PURPA	Public Utility Regulatory Policies Act of 1978
R&D	Research and Development
REC	Renewable Energy Credit
RFC	ReliabilityFirst
RFP	Request for Proposal
RGGI	Regional Greenhouse Gas Initiative
ROE	Return on Equity
RPM	Reliability Pricing Model
RPS	Rules Governing Alternative and Renewable Energy Portfolio Standard
RTEP	Regional Transmission Expansion Plan
RTO	Regional Transmission Organization
S&P	Standard & Poor’s Ratings Service
SB221	Amended Substitute Senate Bill 221
SBC	Societal Benefits Charge
SEC	United States Securities and Exchange Commission
SIP	State Implementation Plan(s) Under the Clean Air Act
SMIP	Smart Meter Implementation Plan
SO_2	Sulfur Dioxide
SOS	Standard Offer Service
SREC	Solar Renewable Energy Credit
TBC	Transition Bond Charge
TDS	Total Dissolved Solid
TMDL	Total Maximum Daily Load
TMI-2	Three Mile Island Unit 2
TO	Transmission Owner
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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Item 5. Market for Registrant’s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

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PART I

ITEM 1. BUSINESS

The Company

FirstEnergy Corp. was organized under the laws of the State of Ohio in 1996. FirstEnergy's principal business is the holding, directly or indirectly, of all of the outstanding common stock of its principal subsidiaries: OE, CEI, TE, Penn (a wholly owned subsidiary of OE), ATSI, JCP&L, Met-Ed, Penelec, AE and its principal subsidiaries (AE Supply, AGC, MP, PE, WP, AET and its principal subsidiaries (TrAIL and PATH), and AESC), FES and its principal 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. In addition, FirstEnergy holds all of the outstanding common stock of other direct subsidiaries including: FirstEnergy Properties, Inc., FEV, FENOC, FELHC, Inc., FirstEnergy Facilities Services Group, LLC, FirstEnergy Fiber Holdings Corp., GPU Power, Inc., GPU Nuclear, Inc., MARBEL Energy Corporation and FESC.

Subsidiaries

FirstEnergy's revenues are primarily derived from electric service provided by its utility operating subsidiaries (OE, CEI, TE, Penn, ATSI, JCP&L, Met-Ed, Penelec, MP, PE, WP and TrAIL) and the sale of energy and related products and services by its unregulated competitive subsidiaries, FES and AE Supply.

The Utilities' combined service areas encompass approximately 65,000 square miles in Ohio, Pennsylvania, West Virginia, Maryland, New Jersey and New York. The areas they serve have a combined population of approximately 13.6 million.

OE was organized under the laws of the State of Ohio in 1930 and owns property and does business as an electric public utility in that state. OE engages in the distribution and sale of electric energy to communities in a 7,000 square mile area of central and northeastern Ohio. The area it serves has a population of approximately 2.3 million. OE complies with the regulations, orders, policies and practices prescribed by the SEC, FERC and PUCO.

OE owns all of Penn's outstanding common stock. Penn was organized under the laws of the Commonwealth of Pennsylvania in 1930 and owns property and does business as an electric public utility in that state. Penn is also authorized to do business in the State of Ohio. Penn furnishes electric service to communities in 1,100 square miles of western Pennsylvania. The area it serves has a population of approximately 0.4 million. Penn complies with the regulations, orders, policies and practices prescribed by the SEC, FERC and PPUC.

CEI was organized under the laws of the State of Ohio in 1892 and does business as an electric public utility in that state. CEI engages in the distribution and sale of electric energy in an area of 1,600 square miles in northeastern Ohio. The area it serves has a population of approximately 1.7 million. CEI complies with the regulations, orders, policies and practices prescribed by the SEC, FERC and PUCO.

TE was organized under the laws of the State of Ohio in 1901 and does business as an electric public utility in that state. TE engages in the distribution and sale of electric energy in an area of 2,300 square miles in northwestern Ohio. The area it serves has a population of approximately 0.7 million. TE complies with the regulations, orders, policies and practices prescribed by the SEC, FERC and PUCO.

ATSI was organized under the laws of the State of Ohio in 1998. ATSI owns major, high-voltage transmission facilities, which consist of approximately 5,800 pole miles of transmission lines with nominal voltages of 345 kV, 138 kV and 69 kV. On June 1, 2011, ATSI transferred operational control of its transmission facilities from MISO to PJM (see FERC Matters for RTO Realignment). ATSI plans, operates, and maintains its transmission system in accordance with NERC reliability standards, and applicable regulatory requirements to ensure reliable service to customers. ATSI complies with the regulations, orders, policies and practices prescribed by the SEC, FERC and applicable state regulatory authorities.

JCP&L was organized under the laws of the State of New Jersey in 1925 and owns property and does business as an electric public utility in that state. JCP&L provides transmission and distribution services in 3,200 square miles of northern, western and east central New Jersey. The area it serves has a population of approximately 2.7 million. JCP&L also has an ownership interest in a hydroelectric generating facility. JCP&L complies with the regulations, orders, policies and practices prescribed by the SEC, FERC and the NJBPU.

Met-Ed was organized under the laws of the Commonwealth of Pennsylvania in 1922 and owns property and does business as an electric public utility in that state. Met-Ed provides transmission and distribution services in 3,300 square miles of eastern and south central Pennsylvania. The area it serves has a population of approximately 1.2 million. Met-Ed complies with the regulations, orders, policies and practices prescribed by the SEC, FERC and PPUC.

Penelec was organized under the laws of the Commonwealth of Pennsylvania in 1919 and owns property and does business as an electric public utility in that state. Penelec provides transmission and distribution services in 17,600 square miles of western, northern and south central Pennsylvania. The area it serves has a population of approximately 1.3 million. Penelec, as lessee of the property of its subsidiary, The Waverly Electric Light & Power Company, also serves customers in the Waverly, New York vicinity.

Penelec complies with the regulations, orders, policies and practices prescribed by the SEC, FERC, NYPSC and PPUC, as applicable.

PE was organized under the laws of the State of Maryland in 1923 and in the Commonwealth of Virginia in 1974. PE is authorized to do business in the Commonwealth of Virginia and the States of West Virginia and Maryland. PE owns property and does business as an electric public utility in those states. PE provides transmission and/or distribution services in 5,500 square miles area in portions of Maryland, Virginia and West Virginia. The area it serves has a population of approximately 0.9 million. PE complies with the regulations, orders, policies and practices prescribed by the SEC, FERC, MDPSC, VSCC, and WVPSC, as applicable.

MP was organized under the laws of the State of Ohio in 1924 and owns property and does business as an electric public utility in the state of West Virginia. MP provides transmission and distribution services in 13,000 square miles of northern West Virginia. The area it serves has a population of approximately 0.8 million. MP also owns generation assets. As of December 31, 2011, MP owned or contractually controlled 2,737 MWs of generation capacity that is supplied to its electric utility business. In addition, MP is contractually obligated to provide PE with the power that it needs to meet its load obligations in West Virginia. MP complies with the regulations, orders, policies and practices prescribed by the SEC, FERC and WVPSC, as applicable.

WP was organized under the laws of the Commonwealth of Pennsylvania in 1916 and owns property and does business as an electric public utility in that state. WP provides transmission and distribution services in 10,400 square miles of southwestern, south-central and northern Pennsylvania. The area it serves has a population of approximately 1.6 million. WP complies with the regulations, orders, policies and practices prescribed by the SEC, FERC and PPUC, as applicable.

TrAIL was organized under the laws of the State of Maryland and the Commonwealth of Virginia in 2006. TrAIL was formed in connection with the management and financing of a new 500kV transmission line. On May 19, 2011, TrAIL completed the construction and energized the transmission line. The transmission line extends approximately 150 miles from southwestern Pennsylvania through West Virginia to a point of interconnection with Virginia Electric and Power Company, a subsidiary of Dominion Resources, in northern Virginia. TrAIL complies with the regulations, orders, policies and practices prescribed by the SEC, FERC, WVPSC, VSCC and PPUC, as applicable.

FES was organized under the laws of the State of Ohio in 1997. FES provides energy-related products and services to wholesale and retail customers. FES also owns and operates, through its subsidiary, FGCO, fossil and hydroelectric generating facilities and owns, through its subsidiary, NGC, FirstEnergy's nuclear generating facilities. FENOC, a separate subsidiary of FirstEnergy, organized under the laws of the State of Ohio in 1998, operates and maintains NGC's nuclear generating facilities. FES purchases the entire output of the generation facilities owned by FGCO and NGC, 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.

AE Supply was organized under the laws of the State of Delaware in 1999. AE Supply provides energy-related products and services to wholesale and retail customers. AE Supply also owns and operates fossil and hydroelectric generating facilities and purchases and sells energy and energy-related commodities.

AGC was organized under the laws of the Commonwealth of Virginia in 1981. AGC is owned approximately 59% by AE Supply and approximately 41% by MP. AGC's sole asset is a 40% undivided interest in the Bath County, Virginia pumped-storage hydroelectric generation facility and its connecting transmission facilities. AGC provides the generation capacity from this facility to AE Supply and MP.

Competitive and Regulated Generation

FirstEnergy's generating portfolio includes 22,810 MW of diversified capacity (Competitive — 19,874 MW and Regulated — 2,936 MW), including 3,349 MW (Competitive - 2,689 MW and Regulated - 660 MW) of capacity that is planned to be retired by September 1, 2012, subject to review of reliability impacts by PJM (See Part I, Item 2. Properties). Of the generation asset portfolio, approximately 14,678 MW (64.4%), consist of coal-fired capacity; 3,991 MW (17.5%) consist of nuclear capacity; 1,832 MW (8.0%) consist of hydroelectric capacity; 1,745 MW (7.7%) consist of oil and natural gas units; 376 MW (1.6%) consist of wind facilities; and 188 MW (0.8%) consist of capacity from FGCO's 4.85% and AE's 3.5% entitlements to the generation output owned by OVEC. All units are located within PJM and sell electric energy, capacity and other products into the wholesale markets that are operated by PJM.

Within the Competitive portfolio, 12,368 MW consist of FES' facilities that are operated by FENOC and FGCO (including entitlements to OVEC), except for portions of certain facilities that are subject to the sale and leaseback arrangements with non-affiliates referred to above for which the corresponding output is available to FES through power sale agreements, and are owned directly by NGC and FGCO, respectively. 7,506 MW consist of AE Supply's facilities, including 660 MW from AGC's Bath County, Virginia hydroelectric facility that AE Supply partially owns. FES' generating facilities are concentrated primarily in Ohio and Pennsylvania and AE Supply's primarily in Pennsylvania, West Virginia and Maryland.

Within the Regulated portfolio, 200 MW consist of JCP&L's 50% ownership interest in the Yards Creek hydroelectric facility in New Jersey; 2,725 MW consist of MP's facilities, including 450 MW from AGC's Bath County, Virginia hydroelectric facility that MP partially owns. MP's facilities are concentrated primarily in West Virginia. 11 MW consist of AE's 3.5% entitlement to OVEC's generation output.

FES, FGCO, NGC, AE Supply and AGC comply with the regulations, orders, policies and practices prescribed by the SEC and the FERC. In addition, NGC and FENOC comply with the regulations, orders, policies and practices prescribed by the NRC.

FESC and AESC provide legal, financial and other corporate support services to affiliated FirstEnergy companies.

Reference is made to Note 19, Segment Information, of the Combined Notes to the Consolidated Financial Statements for information regarding FirstEnergy's reportable segments, which information is incorporated herein by reference.

Utility Regulation

State Regulation

Each of the Utilities' retail rates, conditions of service, issuance of securities and other matters are subject to regulation in the states in which each company operates — in Maryland by the MDPSC, in Ohio by the PUCO, in New Jersey by the NJBPU, in Pennsylvania by the PPUC, in West Virginia by the WVPSC and in New York by the NYPSC. The transmission operations of PE in Virginia are subject to certain regulations of the VSCC. In addition, under Ohio law, municipalities may regulate rates of a public utility, subject to appeal to the PUCO if not acceptable to the utility.

As a competitive retail electric supplier serving retail customers primarily in Ohio, Pennsylvania, Illinois, Michigan, New Jersey and Maryland, FES and AE Supply are subject to state laws applicable to competitive electric suppliers in those states, including affiliate codes of conduct that apply to FES, AE Supply and its public utility affiliates. In addition, if FES, AE Supply or any of its subsidiaries were to engage in the construction of significant new generation facilities, they would also be subject to state siting authority.

Federal Regulation

With respect to their wholesale and interstate electric operations and rates, the Utilities, AE Supply, ATSI, AGC, FES, FGCO, NGC, PATH and TrAIL are subject to regulation by the FERC. Under the FPA, the FERC regulates rates for interstate sales at wholesale, transmission of electric power, accounting and other matters, including construction and operation of hydroelectric projects. The FERC regulations require ATSI, JCP&L, Met-Ed, MP, PATH, PE, Penelec, WP and TrAIL to provide open access transmission service at FERC-approved rates, terms and conditions. Through May 31, 2011, transmission service over ATSI's facilities was provided by MISO under its open access transmission tariff. For JCP&L, Met-Ed, MP, PATH, PE, Penelec, WP and TrAIL and, effective June 1, 2011 for ATSI, transmission service is provided by PJM under its open access transmission tariff. The FERC also regulates unbundled transmission service to retail customers. See FERC Matters RTO Realignment below.

The FERC regulates the sale of power for resale in interstate commerce in part by granting authority to public utilities to sell wholesale power at market-based rates upon a showing that the seller cannot exert market power in generation or transmission. OE, CEI, TE, Penn, JCP&L, MetEd, Penelec, MP, WP, and PE each have been authorized by FERC to sell wholesale power in interstate commerce and have a market-based rates tariff on file with the FERC; although major wholesale purchases and sales remain subject to regulation by the relevant state commissions. AE Supply, FES, FGCO and NGC each have been authorized by the FERC to sell wholesale power in interstate commerce and have a market-based tariff on file with the FERC. By virtue of this tariff and authority to sell wholesale power, each company is regulated as a public utility under the FPA. However, consistent with its historical practice, the FERC has granted AE Supply, FES, FGCO and NGC a waiver from most of the reporting, record-keeping and accounting requirements that typically apply to traditional public utilities. Along with market-based rate authority, the FERC also granted AE Supply, FES, FGCO and NGC blanket authority to issue securities and assume liabilities under Section 204 of the FPA. As a condition to selling electricity on a wholesale basis at market-based rates, AE Supply, FES, FGCO and NGC, like all other entities granted market-based rate authority, must file electronic quarterly reports with the FERC, listing their sales transactions for the prior quarter.

The nuclear generating facilities owned and leased by NGC are subject to extensive regulation by the NRC. The NRC subjects nuclear generating stations to continuing review and regulation covering, among other things, operations, maintenance, emergency planning, security and environmental and radiological aspects of those stations. The NRC may modify, suspend or revoke operating licenses and impose civil penalties for failure to comply with the Atomic Energy Act, the regulations under such Act or the terms of the licenses. FENOC is the licensee for the operating nuclear plants and has direct compliance responsibility for NRC matters. FES controls the economic dispatch of NGC's plants. See Nuclear Regulation below.

Regulatory Accounting

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

FirstEnergy accounts for the effects of regulation through the application of regulatory accounting to the Utilities, ATSI, PATH and TrAIL since each of their rates are established by a third-party regulator with the authority to set rates that bind customers, are cost-

based and can be charged to and collected from customers.
An enterprise meeting all of these criteria capitalizes costs that would otherwise be charged to expense (regulatory assets) if the rate actions of its regulator make it probable that those costs will be recovered in future revenue. Regulatory accounting is applied only to the parts of the business that meet the above criteria. If a portion of the business applying regulatory accounting no longer meets those requirements, previously recorded net regulatory assets are removed from the balance sheet in accordance with GAAP.
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, AE Supply, FGCO, FENOC, ATSI and TrAIL. The NERC is the ERO designated by FERC to establish and enforce these reliability standards, although NERC has delegated day-to-day implementation and enforcement of these reliability standards to eight regional entities, including RFC. All of FirstEnergy's facilities are located within the RFC region. FirstEnergy actively participates in the NERC and RFC 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 RFC.

FirstEnergy believes that it 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 RFC. Moreover, it is clear that the NERC, RFC 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. 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, the NERC may take with respect to this matter.

On August 23, 2010, FirstEnergy self-reported to RFC 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, RFC issued a notice of enforcement to investigate the incident. FirstEnergy submitted a data response to RFC on September 27, 2010. On July 8, 2011, RFC and Met-Ed signed a settlement agreement to resolve all outstanding issues related to the vegetation encroachment event. The settlement calls for Met-Ed to pay a penalty of $650,000, and for FirstEnergy to perform certain mitigating actions. These mitigating actions include inspecting FirstEnergy's transmission system using LiDAR technology, and reporting the results of inspections, and any follow-up work, to RFC. FirstEnergy was performing the LiDAR work in response to certain other industry directives issued by NERC in 2010. NERC subsequently approved the settlement agreement and, on September 30, 2011, submitted the approved settlement to FERC for final approval. FERC approved the settlement agreement on October 28, 2011. Met-Ed subsequently paid the $650,000 penalty and, on December 31, 2011, RFC sent written notice that this matter has been closed.

In 2011, RFC performed routine compliance audits of parts of FirstEnergy's bulk-power system and generally found the audited systems and process to be in full compliance with all audited reliability standards. RFC will perform additional audits in 2012.

Maryland Regulatory Matters

By statute enacted in 2007, the obligation of Maryland utilities to provide SOS to residential and small commercial customers, in exchange for recovery of their costs plus a reasonable profit, was extended indefinitely. The legislation also established a 5-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 current settlement expires at the end of 2012 will depend on developments with respect to SOS in Maryland over the coming year, 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 proceeding.

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 December 2010, the MDPSC issued an order soliciting comments on a model RFP for solicitation of long-term energy commitments by Maryland electric utilities. PE and numerous other parties filed comments, and on September 29, 2011, the MDPSC issued an order requiring the utilities to issue the RFP crafted by the MDPSC by October 7, 2011. The RFPs were issued by the utilities as ordered by the MDPSC. The order, as amended, indicated that bids were due by January 20, 2012, and that the MDPSC would be the entity evaluating all bids. The Chairman of the MDPSC has stated publicly that several bids were received, but no other information was released. After receipt of further comments from interested parties, including PE, on January 13, 2012, a hearing on whether more generation is needed, irrespective of what bids may have been received, was held on January 31, 2012. There has been no further action on 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 for the PE programs for the period of 2009 to 2015 and would be recovered over that six year period. Meanwhile, after extensive meetings with the MDPSC Staff and other stakeholders, PE's plans for additional and improved programs for the period 2012-2014 were filed on August 31, 2011. The MDPSC held hearings on PE's and the other utilities' plans in October 2011, and on December 22, 2011, issued an order approving Potomac Edison's plan with various modifications and follow-up assignments. On January 23, 2012, PE filed a Request for Rehearing because additional facts not considered by the MDPSC demonstrate, among other things, that conservation voltage reduction program expenditures should be accorded cost recovery through the EmPOWER surcharge, as has been provided for all other EmPOWER programs as opposed to recovery of those expenditures being addressed in a future base rate case as the MDPSC found in its order.

In March 2009, the MDPSC issued an order temporarily suspending 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 collect data on payment plan and related issues and has adopted 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.

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 required to assess each utility's compliance with the new rules, and may assess penalties of up to $25,000 per day per violation. The MDPSC convened a working group of utilities, regulators, and other interested stakeholders to address the topics of the proposed rules. A draft of the rules was filed, along with the report of the working group, on October 27, 2011. Hearings to consider the rules and comments occurred over four days between December 8 and 15, 2011, after which revised rules were sent for legislative review. The proposed rules were published in the Maryland Register on February 24, 2012, and a deadline of March 26, 2012, was set for the filing of further comments. A further hearing is required before the rules could become final. Separately, on July 7, 2011, the MDPSC adopted draft rules requiring monitoring and inspections for contact voltage. The draft rules were published in September, 2011. After a further hearing in October, 2011, the final rules were re-published and became effective on November 28, 2011.

New Jersey Regulatory Matters

On September 8, 2011, the Division of Rate Counsel filed a Petition with the NJBPU asserting that it has reason to believe that JCP&L is earning an unreasonable return on its New Jersey jurisdictional rate base. The Division of Rate Counsel requests that the NJBPU order JCP&L to file a base rate case petition so that the NJBPU may determine whether JCP&L's current rates for electric service are just and reasonable. JCP&L filed an answer to the Petition on September 28, 2011, stating, inter alia, that the Division of Rate Counsel analysis upon which it premises its Petition contains errors and inaccuracies, that JCP&L's achieved return on equity is currently within a reasonable range, and that there is no reason for the NJBPU to require JCP&L to file a base rate case at this time. On November 30, 2011, the NJBPU ordered that the matter be assigned to the NJBPU President to act as presiding officer to set and modify the schedule for this matter as appropriate, decide upon motions, and otherwise control the conduct of this case, without the need for full Board approval. The matter is pending and a schedule for further proceedings has not yet been established.

On September 22, 2011, the NJBPU ordered that JCP&L hire a Special Reliability Master, subject to NJBPU approval, to evaluate

JCP&L's design, operating, maintenance and performance standards as they pertain to the Morristown, New Jersey underground electric distribution system, and make recommendations to JCP&L and the NJBPU on the appropriate courses of action necessary to ensure adequate reliability and safety in the Morristown underground network. On October 12, 2011, the Special Reliability Master was selected and on January 31, 2012, the project report was submitted to the Company and NJBPU Staff. On February 10, 2012, the NJBPU accepted the report and directed the Staff to present recommendations on March 12, 2012, on actions required by JCP&L to ensure the safe, reliable operation of the Morristown network.

Pursuant to a formal Notice issued by the NJBPU on September 14, 2011, public hearings were held on September 26 and 27, 2011, to solicit public comments regarding the state of preparedness and responsiveness of the local electric distribution companies prior to, during and after Hurricane Irene. By subsequent Notice issued September 28, 2011, additional hearings were held in October 2011. Additionally, the NJBPU accepted written comments through October 31, 2011 related to this inquiry. On December 4, 2011, the NJBPU Division of Reliability and Security issued a Request for Qualifications soliciting bid proposals from qualified consulting firms to provide expertise in the review and evaluation of New Jersey's electric distribution companies' preparation and restoration to Hurricane Irene and the October 2011 snowstorm. Responsive bids were submitted on January 20, 2012, and the report of selected bidder is to be submitted to the NJPBU 120 days from the date the contract is awarded. On December 14, 2011, the NJBPU Staff filed a report of its preliminary findings and recommendations with respect to the electric utility companies' planning and response to Hurricane Irene and the October 2011 snowstorm. The NJBPU has not indicated what additional action, if any, may be taken as a result of information obtained through this process.

Ohio Regulatory Matters

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; 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, 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 in 2012. The PUCO issued an Opinion and Order generally approving the Ohio Companies' three-year plan, and the Ohio 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. Moreover, because the PUCO indicated, when approving the 2009 benchmark request, that it would modify the Ohio 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 May 19, 2011, the PUCO granted the request to reduce the 2010 energy efficiency and peak demand reductions to the level achieved in 2010 for OE, while finding that the motion was moot for CEI and TE. On June 2, 2011, the Ohio Companies filed an application for rehearing to clarify the decision related to CEI and TE. On July 27, 2011, the PUCO denied that application for rehearing, but clarified that CEI and TE could apply for an amendment in the future for the 2010 benchmarks should it be necessary to do so. Failure to comply with the benchmarks or to obtain such an amendment may subject the Ohio Companies to an assessment of a penalty by the PUCO. In addition to approving the programs included in the plan, with only minor modifications, the PUCO authorized the Ohio 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 by the Ohio Companies, Ohio Energy Group and Nucor Steel Marion, Inc. 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 September 7, 2011, the PUCO denied those applications for rehearing. The PUCO also included a new standard for compliance with the statutory energy efficiency benchmarks by requiring electric distribution companies to offer “all available cost effective energy efficiency opportunities” regardless of their level of compliance with the benchmarks as set forth in the statute. On October 7, 2011, the Ohio Companies, the Industrial Energy Users - Ohio, and the Ohio Energy Group filed applications for rehearing, arguing that the PUCO'S new standard is unlawful. The Ohio Companies also asked the PUCO to withdraw its amendment of CEI's and TE's 2010 energy efficiency benchmarks. The PUCO did not rule on the Applications for Rehearing within thirty days, thus denying them by operation of law. On December 30, 2011, the Ohio Companies filed a notice of appeal with the Supreme Court of Ohio, challenging the PUCO's new standard. No procedural schedule has been established.

Additionally, under SB221, electric utilities and electric service companies are required to serve part of their load in 2011 from renewable energy resources equivalent to 1.00% of the average of the KWH they served in 2008-2010; in 2012 from renewable energy resources equivalent to 1.50% of the average of the KWH they served in 2009-2011; and in 2013 from renewable energy resources equivalent to 2.00% of the average of the KWH they served in 2010-2012. 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 SRECs 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. 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. On August 3, 2011, the PUCO granted the Ohio Companies' force majeure request for 2010 and increased their 2011 benchmark by the amount of SRECs generated in Ohio that the Ohio Companies were short in 2010. On September 2, 2011, the Environmental Law and Policy Center and Nucor Steel Marion, Inc. filed applications for rehearing. The Ohio Companies filed their response on September 12, 2011. These applications for rehearing were denied by the PUCO on September 20, 2011, but as part of its Entry on Rehearing the PUCO opened a new docket to review the Ohio Companies' alternative energy recovery rider. Separately, one party has filed a request that the PUCO audit the cost of the Ohio Companies' compliance with the alternative energy requirements and the Ohio Companies' compliance with Ohio law. The PUCO selected auditors to perform a financial and a management audit, and final audit reports are to be filed with the PUCO by May 15, 2012. In August 2011, the Ohio Companies conducted two RFP processes to obtain RECs to meet the statutory benchmarks for 2011 and beyond.

Pennsylvania Regulatory Matters

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 customers 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 are continuing 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 the U.S. District Court for the Eastern District of Pennsylvania, which was subsequently amended. The PPUC filed a Motion to Dismiss Met-Ed's and Penelec's Amended Complaint on September 15, 2011. Met-Ed and Penelec filed a Responsive brief in Opposition to the PPUC's Motion to Dismiss on October 11, 2011. 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 each of May 2008, 2009 and 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 DSP 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, (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 provides for potentially significant financial penalties to be assessed upon utilities that fail to achieve the required reductions in consumption and peak demand. Act 129 also required utilities to file a SMIP with the PPUC.

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 became 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 ALJ. On December 15, 2011, the ALJ recommended that the amended plans be approved as proposed, and on January 12, 2012, the Commission approved the plans.

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 September 2010, WP filed an amended EE&C Plan that is less reliant on smart meter deployment, which the PPUC approved in January 2011.

On August 9, 2011, WP filed a petition to approve its Second Amended EE&C Plan. The proposed Second Revised Plan includes measures and a new program and implementation strategies consistent with the successful EE&C programs of Met-Ed, Penelec and Penn that are designed to enable WP to achieve the post-2011 Act 129 EE&C requirements. On January 6, 2012, a Joint Petition for Settlement of all issues was filed by the parties to the proceeding.

The Pennsylvania Companies submitted a preliminary report on July 15, 2011, and a final report on November 15, 2011, in which they reported on their compliance with statutory May 31, 2011, energy efficiency benchmarks. Met-Ed, Penelec and Penn achieved the 2011 benchmarks; however WP has been unable to provide final results because several customers are still accumulating necessary documentation for projects that may qualify for inclusion in the final results. Preliminary numbers indicate that WP did not achieve its 2011 benchmark and it is not known at this time whether WP will be subject to a fine for failure to achieve the benchmark. WP is unable to predict the outcome of this matter or estimate any possible loss or range of loss.

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 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.

Following additional proceedings, 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. A Joint Stipulation with the OSBA was also filed on March 9, 2011. The PPUC approved the Amended Joint Petition for Full Settlement 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 accounting method utilized by Met-Ed and Penelec. On January 30, 2012, the Commission entered a final order approving Met-Ed's and Penelec's accounting methodology whereby NUG over-collection revenue may be used to reduce non-NUG stranded costs, even if a cumulative NUG stranded cost balance exists.

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 concerning retail markets in Pennsylvania. Met-Ed, Penelec, Penn Power and WP 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. A technical conference was held on August 10, 2011, and a second en banc was held on November 10, 2011, to discuss intermediate steps that can be taken to promote the development of a competitive market. Teleconferences are scheduled through March 2012, with another en banc hearing to be held on March 21, 2012, to explore the future of default service in Pennsylvania following the expiration of the upcoming default service plans on May 31, 2015. Following the issuance of a Tentative Order and comments filed by numerous parties, the Commission entered a final order on December 16, 2011, providing recommendations for components to be included in upcoming default service plans. An intermediate work plan was also presented on December 16, 2011, by Tentative Order, on which initial comments were submitted by Met-Ed, Penelec, Penn and WP on January 17, 2012. FES also submitted comments. Reply comments were submitted on February 1, 2012. It is expected that a final order implementing the intermediate work plan and a long range plan will be presented by the PPUC, both in March 2012.

The PPUC issued a Proposed Rulemaking Order on August 25, 2011, which proposed a number of substantial modifications to the current Code of Conduct regulations that were promulgated to provide competitive safeguards to the competitive retail electric market in Pennsylvania. The proposed changes include, but are not limited to: an EGS may not have the same or substantially similar name as the EDC or its corporate parent; EDCs and EGSs would not be permitted to share office space and would need to occupy different buildings; EDCs and affiliated EGSs could not share employees or services, except certain corporate support, emergency, or tariff services (the definition of "corporate support services" excludes items such as information systems, electronic data interchange, strategic management and planning, regulatory services, legal services, or commodities that have been included in regulated rates at less than market value); and an EGS must enter into a trademark agreement with the EDC before using its trademark or service mark. The Proposed Rulemaking Order, which was published on February 11, 2012, calls for comments to be submitted by March 27, 2012. If implemented these rules could require a significant change in the way FES, Met-Ed, Penelec, Penn and WP do business in Pennsylvania, and could possibly have an adverse impact on their results of operations and financial condition.

In November 2011, Met-Ed, Penelec, Penn and WP filed a Joint Petition for Approval of their Default Service Plan for the period June 1, 2013 through May 31, 2015. The Pennsylvania Companies' direct case was submitted in its entirety on December 20, 2011. Evidentiary hearings are scheduled for April 11-13, 2012, and a final order must be entered by the PPUC by August 17, 2012.

West Virginia Regulatory Matters

In 2009, the West Virginia Legislature enacted the AREPA, 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 10% by 2015, 15% by 2020, and 25% by 2025. In November 2010, the WVPSC issued 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 was issued by the WVPSC in September 2011, which conditionally approved MP's and PE's compliance plan, contingent on the outcome of the resource credits case discussed below.

Additionally, in January 2011, MP and PE filed an application with the WVPSC seeking to certify three facilities as Qualified Energy Resource Facilities. The application was approved and the three facilities are capable of generating renewable credits which will assist the companies in meeting their combined requirements under the AREPA. An annual update filing is due on March 31, 2012. 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 West Virginia. 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. A hearing was held at the WVPSC on August 25 and 26, 2011. On November 22, 2011, the WVPSC issued an order granting ownership of all RECs produced by the facilities to MP. On December 22, 2011, the WVPSC order was appealed, and the order was stayed pending the outcome of the appeal. MP's brief was filed on February 13, 2012. Should MP be unsuccessful in the appeal, it will have to procure the requisite RECs to comply with AREPA from other sources. MP expects to recover such costs from customers.

In September 2011, MP and PE filed with the WVPSC to recover costs associated with fuel and purchased power (the ENEC) in the amount of $32 million which represents an approximate 3% overall increase in such costs over the past two years, primarily attributable to rising coal prices. The requested increase was partially offset by $2.5 million of synergy savings directly resulting from the merger of FirstEnergy and AE, which closed in February 2011. Under a cost recovery clause established by the WVPSC in 2007, MP and PE customer bills are adjusted periodically to reflect upward or downward changes in the cost of fuel and purchased power. The utilities' most recent request to recover costs for fuel and purchased power was in September 2009. MP and PE entered into a Settlement Agreement related to this matter. The WVPSC issued an order on December 30, 2011, approving the settlement agreement. The approved settlement resulted in an increase of $19.6 million, instead of the requested $32 million, with additional costs to be recovered over time with a carrying charge.

FERC Matters

PJM Transmission Rate

In April 2007, FERC issued 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, 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 and higher voltage facilities on a load ratio share basis and, based on this finding, remanded the rate design issue to FERC.

In an order dated January 21, 2010, FERC set the matter for a “paper hearing” and requested 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 load serving entities 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. Other utilities and state commissions supported continued socialization of these costs on a load ratio share basis. This matter is awaiting action by FERC. FirstEnergy cannot predict the outcome of this matter or estimate the possible loss or range of loss.

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 TOs (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 analysis as part of FERC's evaluation of ATSI's proposed transmission rates. Finally, and also on June 30, 2011, the MISO and the MISO TOs filed a competing compliance filing - one that would require ATSI to pay certain charges related to construction and operation of transmission projects within the MISO even though FERC ruled that ATSI cannot pass these costs on to ATSI's customers. ATSI on the one hand, and the MISO and MISO TOs on the other, have submitted subsequent filings - each of which is intended to refute the other's claims. ATSI's compliance filing and request for rehearing, as well as the pleadings that reflect the dispute between ATSI and the MISO/MISO TOs, are currently pending before FERC.

From late April 2011 through June 2011, FERC issued other orders that address ATSI's move into PJM. Also, 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 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. Despite being presented with the issue by FirstEnergy and the MISO, the FERC did not address clearly the question of 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 requested 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. On October 21, 2011, FERC issued its order on rehearing, but that order did not address FirstEnergy's argument directly. FERC ruled instead that if ATSI was subject to MVP charges then ATSI owed these charges upon exit of the MISO. On October 31, 2011, FESC filed a Petition of Review for the FERC's December 2010 order and October 21, 2011 order on rehearing of that order with the U.S. Court of Appeals for the D.C. Circuit. Other parties also filed appeals of those orders and, in November, 2011, the cases were consolidated for briefing and disposition in the U.S. Court of Appeals for the Seventh Circuit. On January 27, 2012, the court ordered the FERC to file a proposed briefing format and schedule on or before March 20, 2012.

On August 3, 2011, FirstEnergy filed a complaint with FERC based on the FERC's December 2010 order. In the complaint, FirstEnergy argued that ATSI perfected the legal and financial requirements necessary to exit MISO before any MVP responsibilities could attach and asked FERC to rule that MISO cannot charge ATSI for MVP costs. On September 2, 2011, MISO, its TOs and other parties, filed responsive pleadings. On September 19, 2011, ATSI filed an answer. On December 29, 2011, the MISO and the MISO TOs filed a new "Schedule 39" to the MISO's tariff. Schedule 39 purports to establish a process whereby the MISO would bill TOs for MVP costs that, according to the MISO, attached to the utility prior to such TOs withdrawal from the MISO. On January 19, 2012, FirstEnergy filed a protest to the MISO's new Schedule 39 tariff.

On February 27, 2012, FERC issued an order (February 2012 Order) dismissing ATSI's August 3, 2011 complaint. In the February 2012 Order, FERC accepted the MISO's Schedule 39 tariff, subject to hearings and potential refund of MVP charges to ATSI. The basis for any subsequent hearing is whether the Schedule 39 tariff was in effect at the time that ATSI exited the MISO. FirstEnergy is evaluating the February 2012 Order and will determine the next steps.

FirstEnergy cannot predict the outcome of these proceedings or estimate the possible loss or range of loss.

FirstEnergy Companies' PJM FTR Contract Underfunding Complaint

On December 28, 2011, FES and AE Supply filed a complaint with FERC against PJM challenging the ongoing underfunding of FTR contracts, which exist to hedge against transmission congestion in the day-ahead markets. The underfunding is a result of PJM's practice of using the funds that are intended to pay the holders of FTR contracts to pay instead for congestion costs that occur in the real time markets. Underfunding of the FTR contracts resulted in losses of approximately $35 million to FES and AE Supply in the 2010-2011 Delivery Year. To date, losses for the 2011-2012 Delivery Year are estimated to be approximately $6 million.

On January 13, 2012, PJM filed comments that describe changes to the PJM tariff that, if adopted, should remedy the underfunding issue. Many parties also filed comments supporting FES' and AE Supply's position. Other parties, generally representatives of end-use customers who will have to pay the charges, filed in opposition to the complaint. The matter is currently pending before FERC. FirstEnergy cannot predict the outcome of this matter or estimate the possible loss or range of loss.

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 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. On June 3, 2011, the California parties requested rehearing of the May 4, 2011 order. The request for rehearing remains pending.

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. That request for rehearing also remains pending. FirstEnergy cannot predict the outcome of either of the above matters or estimate the possible loss or range of loss.

PATH Transmission 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 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 ROE 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% ROE incentive adder and a 0.5% ROE adder for RTO participation. These adders will be applied to the base ROE determined as a result of the hearing. The PATH Companies, Joint Intervenors, Joint Consumer Advocates and FERC staff have agreed to a four year moratorium. A settlement was reached, which reflects a base ROE of 10.4% (plus authorized adders) effective January 1, 2011. Accordingly, the revised ROE was reflected in a revised Projected Transmission Revenue Requirement for 2011 with true-up occurring in 2013. The FirstEnergy portion of the refund for March 1, 2008, through December 31, 2010, is approximately $2 million (inclusive of interest). The refund amount was computed using a base ROE of 10.8% plus authorized adders. On October 7, 2011, PATH and six intervenors submitted to FERC an unopposed settlement agreement.

Contemporaneous with this submission, PATH and the six intervenors filed with the Chief ALJ of FERC a joint motion for interim approval and authorization to implement the refund on an interim basis pending issuance of a FERC order acting on the settlement agreement. On October 12, 2011, the motion for interim approval and authorization to implement the refund was granted by the Chief ALJ. On February 16, 2012, FERC approved the settlement agreement and dismissed as moot, in light of its approval of the settlement, PATH's pending request for rehearing of the November 19, 2010 order.

Capital Requirements

Our capital spending for 2012 is expected to be approximately $2.1 billion (excluding nuclear fuel). For 2013, we anticipate baseline capital expenditures of approximately $2.0 billion, which exclude any potential additional strategic opportunities, future mandated spending, energy efficiency or environmental spending relating to MATS. Planned capital initiatives are intended to promote reliability, improve operations, and support current environmental and energy efficiency directives. Our capital investments for additional nuclear fuel are expected to be $280 million and $219 million in 2012 and 2013, respectively.

Anticipated capital expenditures for 2012, excluding nuclear fuel, are shown in the following table. Such costs include expenditures for the betterment of existing facilities and for the construction of transmission lines, distribution lines and substations, and other assets.

	2011 Actual	Capital Expenditures Forecast 2012
	(In millions)	
OE	$178	$167
Penn	30	21
CEI	120	110
TE	47	39
JCP&L	327	206
Met-Ed	138	105
Penelec	159	136
MP	164	142
PE	96	89
WP	153	128
ATSI	113	84
TrAIL	82	20
FGCO	198	131
NGC	409	452
AE Supply	141	144
Other subsidiaries	128	116
Total	$2,483	$2,090

During the 2012-2016 period, maturities of, and sinking fund requirements for long-term debt are:

	2012	2013-2016	Total
	(In millions)		
FE	$—	$150	$150
FES	270	1,758	2,028
OE	—	400	400
Penn	1	4	5
CEI	22	381	403
JCP&L	34	458	492
Met-Ed	—	429	429
Penelec	—	195	195
Other[1]	637	1,631	2,268
Total	$964	$5,406	$6,370

[1] Includes debt of AE and its subsidiaries and the elimination of certain intercompany debt.

The following tables display consolidated operating lease commitments as of December 31, 2011.

Operating Leases	FirstEnergy Lease Payments	Capital Trust[1]	Net
	(In millions)		
2012	$383	$125	$258
2013	382	130	252
2014	371	131	240
2015	373	90	283
2016	344	29	315
Years thereafter	1,803	4	1,799
Total minimum lease payments	$3,656	$509	$3,147

[1] PNBV and Shippingport purchased a portion of the lease obligation bonds associated with certain sale and leaseback transactions. These arrangements effectively reduce lease costs related to those transactions.

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Operating Leases	FES	OE[1]	CEI	TE[1]	JCP&L	Met-Ed	Penelec
	(In millions)						
2012	$237	$147	$4	$64	$7	$4	$3
2013	241	146	3	64	7	4	3
2014	236	145	3	64	6	3	2
2015	239	145	2	64	5	4	2
2016	230	117	3	64	5	3	2
Years thereafter	1,662	49	4	14	48	37	12
Total minimum lease payments	$2,845	$749	$19	$334	$78	$55	$24

(1) Includes certain minimum lease payments associated with NGC's lessor equity interests in Perry and Beaver Valley Unit 2 that are eliminated in consolidation (see Note 6, Leases, of the Combined Notes to the Consolidated Financial Statements).

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. In addition to internal sources to fund liquidity and capital requirements for 2012 and beyond, FirstEnergy expects to 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 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.

FirstEnergy had no significant short-term debt outstanding as of December 31, 2011. Total short-term bank lines of committed credit to FirstEnergy totaled $5.0 billion. FirstEnergy’s available liquidity as of January 31, 2012, was as follows:

Company	Type	Maturity	Commitment	Available Liquidity
			(In millions)	
FirstEnergy[1]	Revolving	June 2016	$2,000	$1,395
FES / AE Supply	Revolving	June 2016	2,500	2,498
TrAIL	Revolving	Jan. 2013	450	450
AGC	Revolving	Dec. 2013	50	—
		Subtotal	$5,000	$4,343
		Cash	—	49
		Total	$5,000	$4,392

(1) FE and the Utilities

FirstEnergy and certain of its subsidiaries participate in two five-year syndicated revolving credit facilities with aggregate commitments of $4.5 billion (Facilities).

An aggregate amount of $2 billion is available to be borrowed under a syndicated revolving credit facility (FirstEnergy Facility), subject to separate borrowing sublimits for each borrower. The borrowers under the FirstEnergy Facility are FE, OE, Penn, CEI, TE, Met-Ed, 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 (FES/AE Supply Facility), subject to separate borrowing sublimits for each borrower.

Commitments under each of the 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 Facilities are available to each borrower separately and 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 Facilities are subject to the usual and customary provisions for acceleration upon the occurrence of events of default, including a cross-default for other indebtedness in excess of $100 million, as described further in Note 12, Capitalization.

FirstEnergy also has established $500 million of revolving credit facilities that are available to TrAIL ($450 million) and AGC ($50 million) until January 2013 and December 2013, respectively.

FE's primary source of cash for continuing operations as a holding company is cash from the operations of its subsidiaries. During 2011, FirstEnergy received $1.8 billion of cash dividends from its subsidiaries and paid $881 million in cash dividends to common shareholders, including $20 million paid in March by AE to its former shareholders.

As of December 31, 2011, the Ohio Companies and Penn had the aggregate capability to issue approximately $2.7 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 $232 million and $20 million, respectively. As a result of the indenture provisions, TE cannot incur any additional secured debt. Met-Ed and Penelec had the capability to issue secured debt of approximately $376 million and $382 million, respectively, under provisions of their senior note indentures as of December 31, 2011. In addition, based upon their respective FMB indentures, net earnings and available bondable property additions as of December 31, 2011, MP, PE and WP had the capability to issue approximately $1.1 billion of additional FMBs in the aggregate. These companies may be further limited by the financial covenants of the Facilities and subject to current regulatory approvals and applicable statutory and/or charter limitations.

Based upon FGCO’s net earnings and available bondable property additions under its FMB indentures as of December 31, 2011, FGCO had the capability to issue $2.1 billion of additional FMBs under the terms of that indenture. Based upon NGC’s net earnings and available bondable property additions under its FMB indenture as of December 31, 2011, NGC had the capability to issue $2.0 billion of additional FMBs under the terms of that indenture.

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

Nuclear Operating Licenses

In August 2010, FENOC submitted an application to the NRC for renewal of the Davis-Besse operating license for an additional twenty years, until 2037. By an order dated April 26, 2011, a NRC 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 from the order granting a hearing on the Davis-Besse license renewal application. On January 10, 2012, intervenors petitioned the ASLB for a new contention on the cracking of the Davis-Besse shield building discussed below.

The following table summarizes the current operating license expiration dates for FES' nuclear facilities in service.

Station	In-Service Date	Current License Expiration
Beaver Valley Unit 1	1976	2036
Beaver Valley Unit 2	1987	2047
Perry	1986	2026
Davis-Besse	1977	2017

Nuclear Regulation

Under NRC regulations, FirstEnergy must ensure that adequate funds will be available to decommission its nuclear facilities. As of December 31, 2011, FirstEnergy had approximately $2 billion invested in external trusts to be used for the decommissioning and environmental remediation of Davis-Besse, Beaver Valley, Perry and TMI-2. 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. 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. By

letter dated December 29, 2011, FENOC informed the NRC staff that it had increased the parental guarantee to $95 million.
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's failure to begin accepting spent nuclear fuel on January 31, 1998. DOE was required to begin 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. In January 2012, the applicable FirstEnergy affiliates reached a $48 million settlement of these claims.
On October 1, 2011, Davis-Besse was safely shut down for a scheduled outage to install a new reactor vessel head and complete other maintenance activities. The new reactor head, which replaced a head installed in 2002, enhances safety and reliability, and features control rod nozzles made of material less susceptible to cracking. On October 10, 2011, following opening of the building

for installation of the new reactor head, a sub-surface hairline crack was identified in one of the exterior architectural elements on the shield building. These elements serve as architectural features and do not have structural significance. During investigation of the crack at the shield building opening, concrete samples and electronic testing found similar sub-surface hairline cracks in most of the building's architectural elements. FENOC's investigation also identified other indications. Included among them were sub-surface hairline cracks in the upper portion of the shield building (above elevation 780') and in the vicinity of the main steam line penetrations. A team of industry-recognized structural concrete experts and Davis-Besse engineers has determined these conditions do not affect the facility's structural integrity or safety.

On December 2, 2011, the NRC issued a CAL which concluded that FENOC provided "reasonable assurance that the shield building remains capable of performing its safety functions." The CAL imposed a number of commitments from FENOC including, submitting a root cause evaluation and corrective actions to the NRC by February 28, 2012, and further evaluations of the shield building. On February 27, 2012, FENOC sent the root cause evaluation to the NRC. Finally, the CAL also stated that the NRC was still evaluating whether the current condition of the shield building conforms to the plant's licensing basis. On December 6, 2011, the Davis-Besse plant returned to service.

By letter dated August 25, 2011, the NRC made a final significance determination (white) associated with a violation that occurred during the retraction of a source range monitor from the Perry reactor vessel. The NRC also placed Perry in the degraded cornerstone column (Column 3) of the NRC's Action Matrix governing the oversight of commercial nuclear reactors. As a result, the NRC staff will conduct several supplemental inspections, culminating in an inspection using Inspection Procedure 95002 to determine if the root cause and contributing causes of risk significant performance issues are understood, the extent of condition has been identified, whether safety culture contributed to the performance issues, and if FENOC's corrective actions are sufficient to address the causes and prevent recurrence.

In light of the impacts of the earthquake and tsunami on the reactors in Fukushima, Japan, the NRC conducted inspections of emergency equipment at U.S. reactors. The NRC also established a Near-Term Task Force to review its processes and regulations in light of the incident, and, on July 12, 2011, the Task Force issued its report of recommendations for regulatory changes. On October 18, 2011, the NRC approved the Staff recommendations, and directed the Staff to implement its near-term recommendations without delay. Ultimately, the adoption of the Staff recommendations on near-term actions is likely to result in additional costs to implement plant modifications and upgrades required by the regulatory process over the next several years, which costs are likely to be material.

On February 16, 2012, the NRC issued a request for information to the licensed operators of 11 nuclear power plants, including Beaver Valley Power Station Units 1 and 2, with respect to the modeling of fuel performance as it relates to "thermal conductivity degradation," which is the potential in older fuel for reduced capacity to transfer heat that could potentially change its performance during various accident scenarios, including loss of coolant accidents. The request for information indicated that this phenomenon has not been accounted for adequately in performance models for the fuel developed by the fuel manufacturer. The NRC is requesting that FENOC provide an analysis to demonstrate that the NRC regulations are being met. Absent that demonstration, the request indicates that the NRC may consider imposing restrictions on reactor operating limits until the issue is satisfactorily resolved.

Nuclear Insurance

The Price-Anderson Act limits the public liability which can be assessed with respect to a nuclear power plant to $12.6 billion (assuming 104 units licensed to operate) for a single nuclear incident, which amount is covered by: (i) private insurance amounting to $375 million; and (ii) $12.2 billion provided by an industry retrospective rating plan required by the NRC pursuant thereto. Under such retrospective rating plan, in the event of a nuclear incident at any unit in the United States resulting in losses in excess of private insurance, up to $118 million (but not more than $18 million per unit per year in the event of more than one incident) must be contributed for each nuclear unit licensed to operate in the country by the licensees thereof to cover liabilities arising out of the incident. Based on their present nuclear ownership and leasehold interests, FirstEnergy’s maximum potential assessment under these provisions would be $470 million (OE-$40 million, NGC-$408 million, and TE-$22 million) per incident but not more than $70 million (OE-$6 million, NGC-$61 million, and TE-$3 million) in any one year for each incident.

In addition to the public liability insurance provided pursuant to the Price-Anderson Act, FirstEnergy has also obtained insurance coverage in limited amounts for economic loss and property damage arising out of nuclear incidents. FirstEnergy is a member of NEIL, which provides coverage (NEIL I) for the extra expense of replacement power incurred due to prolonged accidental outages of nuclear units. Under NEIL I, FirstEnergy's subsidiaries have policies, renewable yearly, corresponding to their respective nuclear interests, which provide an aggregate indemnity of up to approximately $2.0 billion (OE-$168 million, NGC-$1.7 billion, TE-$90 million) for replacement power costs incurred during an outage after an initial 26-week waiting period. Members of NEIL I pay annual premiums and are subject to assessments if losses exceed the accumulated funds available to the insurer. FirstEnergy's present maximum aggregate assessment for incidents at any covered nuclear facility occurring during a policy year would be approximately $13 million (OE-$1 million, NGC-$12 million, and TE-less than $1 million).

FirstEnergy is insured as to its respective nuclear interests under property damage insurance provided by NEIL to the operating company for each plant. Under these arrangements, up to $2.8 billion of coverage for decontamination costs, decommissioning costs, debris removal and repair and/or replacement of property is provided. FirstEnergy pays annual premiums for this coverage and is liable for retrospective assessments of up to approximately $66 million (OE-$6 million, NGC-$57 million, TE-$2 million, Met

Ed, Penelec, and JCP&L-less than $1 million each) during a policy year.
FirstEnergy intends to maintain insurance against nuclear risks as described above as long as it is available. To the extent that replacement power, property damage, decontamination, decommissioning, repair and replacement costs and other such costs arising from a nuclear incident at any of FirstEnergy's plants exceed the policy limits of the insurance in effect with respect to that plant, to the extent a nuclear incident is determined not to be covered by FirstEnergy's insurance policies, or to the extent such insurance becomes unavailable in the future, FirstEnergy would remain at risk for such costs.
The NRC requires nuclear power plant licensees to obtain minimum property insurance coverage of $1.1 billion or the amount generally available from private sources, whichever is less. The proceeds of this insurance are required to be used first to ensure that the licensed reactor is in a safe and stable condition and can be maintained in that condition so as to prevent any significant risk to the public health and safety. Within 30 days of stabilization, the licensee is required to prepare and submit to the NRC a cleanup plan for approval. The plan is required to identify all cleanup operations necessary to decontaminate the reactor sufficiently to permit the resumption of operations or to commence decommissioning. Any property insurance proceeds not already expended to place the reactor in a safe and stable condition must be used first to complete those decontamination operations that are ordered by the NRC. FirstEnergy is unable to predict what effect these requirements may have on the availability of insurance proceeds.
Hydro Relicensing
Yards Creek
The Yards Creek Pumped Storage Project is a 400 MW hydroelectric project located in Warren County, New Jersey. JCP&L owns an undivided 50% interest in the project, and operates the project. PSEG Fossil, LLC, a subsidiary of Public Service Enterprise Group, owns the remaining interest in the plant. The project was constructed in the early 1960s, and became operational in 1965. Authorization to operate the project is by a license issued by the FERC. The existing license expires on February 28, 2013.

In February 2011, JCP&L and PSEG filed a joint application with FERC to renew the license for an additional forty years. The companies are pursuing relicensure through FERC's ILP. Under the ILP, FERC will assess the license applications, issue draft and final Environmental Assessments/Environmental Impact Studies (as required by NEPA), and provide opportunities for intervention and protests by affected third parties. FERC may hold hearings during the two-year ILP licensure period. FirstEnergy expects FERC to issue the new license within the remaining portion of the two-year ILP period. To the extent, however, that the license proceedings extend beyond the February 28, 2013 expiration date for the current license, the current license will be extended yearly as necessary to permit FERC to issue the new license.
Seneca

The Seneca 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 PAD in the license docket.

On November 30, 2010, the Seneca Nation filed its notice of intent to relicense and PADs 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.

On September 12, 2011, FirstEnergy and the Seneca Nation each filed “Revised Study Plan” documents. These documents describe the parties' respective proposals for the scope of the environmental studies that should be performed as part of the relicensing process. On October 11, 2011, FERC Staff issued a letter order that addressed the Revised Study Plans. In the order, FERC Staff approved FirstEnergy's Revised Study Plan, subject to a finding that the Project is located on “aboriginal lands” of the Seneca Nation. Based on this finding, FERC Staff directed FirstEnergy to consult with the Seneca Nation and other parties about the data set, methodology, and modeling of the hydrological impacts of project operations. FirstEnergy is performing the work necessary to develop a study proposal from which to conduct such consultations. The study process will extend through approximately November of 2013.

FirstEnergy cannot predict the outcome of this matter or estimate the possible loss or range of loss.

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 or non-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 air emissions from the coal-fired Bruce Mansfield Plant. 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 complaints.

The states of New Jersey and Connecticut filed CAA citizen suits in 2007 alleging NSR violations at the coal-fired 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 or estimate the possible loss or range of loss.

In January 2009, the EPA issued a NOV to GenOn Energy, Inc. alleging NSR violations at the coal-fired Portland Generation Station based on “modifications” dating back to 1986. 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 and Penelec are unable to predict the outcome of this matter or estimate the possible loss or range of loss.

In each of May and September 2010, New Jersey submitted interstate pollution transport petitions seeking to reduce Portland Generating Station air emissions under section 126 of the CAA. Based on the September 2010 petition, the EPA has finalized emissions limits and compliance schedules to reduce SO_2 air emissions by approximately 81% at the Portland Station by January 6, 2015. New Jersey's May 2010 petition is still under consideration by the EPA.

In June 2008, the EPA issued a Notice and Finding of Violation to 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, NYSEG 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, NYSEG, and various current owners of Homer City, including EME Homer City Generation L.P. and affiliated companies, including Edison International. 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. 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.” In October 2011, the Court dismissed all of the claims with prejudice of the U.S. and the Commonwealth of Pennsylvania and the States of New Jersey and New York and all of the claims of the private parties, without prejudice to re-file state law claims in state court, against all of the defendants, including Penelec. In December 2011, the U.S., the Commonwealth of Pennsylvania and the States of New Jersey and New York all filed notices appealing to the Third Circuit Court of Appeals. Penelec believes the claims are without merit and intends to defend itself against the allegations made in these complaints, but, at this time, is unable to predict the outcome of this matter or estimate the loss or possible range of loss. Mission is seeking indemnification from NYSEG and Penelec, the co-owners of Homer City prior to its sale in 1999. On February 13, 2012, the Sierra Club notified the current owner and operator of Homer City, Homer City OL1-OL8 LLC and EME Homer City Generation L.P., that it intends to file a CAA citizen suit regarding its Title V permit and SO_2 emissions from the Homer City Plant.

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 during maintenance outages dating back to 1990 triggered the pre-construction permitting requirements under the PSD and NNSR programs. FGCO also 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 provisions of the CAA. Later in 2009, FGCO also received another information request regarding emission projections for the 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 or estimate the possible loss or range of loss.

In August 2000, AE received an information request pursuant to section 114(a) of the CAA 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 NSR provisions under the CAA, which can require the installation of additional air emission control equipment when a 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 or estimate the possible loss or range of loss.

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 generation units: 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 coal-fired 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 and we are unable to predict the outcome or estimate the possible loss or range of loss.

In September 2007, Allegheny 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 coal-fired Hatfield's Ferry and Armstrong plants in Pennsylvania and the coal-fired Fort Martin and Willow Island plants in West Virginia.

FirstEnergy intends to vigorously defend against the CAA matters described above but cannot predict their outcomes or estimate the possible loss or range of loss.

State Air Quality Compliance

In early 2006, Maryland passed the Healthy Air Act, which imposes state-wide emission caps on SO_2 and NOx, 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 tenth state to join the RGGI. The Healthy Air Act provides a conditional exemption for the R. Paul Smith coal-fired plant for NOx, SO_2 and mercury, based on a 2006 PJM declaration that the plant is vital to reliability in the Baltimore/Washington DC metropolitan area. Pursuant to the legislation, the MDE passed alternate NOx 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% which began 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. Fourteen RGGI auctions have been held through the end of calendar year 2011. 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. On June 30, 2011, PJM notified MDE that termination of operation at R. Paul Smith would adversely impact the reliability of electrical service in the PJM region absent transmission system upgrades. On January 26, 2012, FirstEnergy announced that R. Paul Smith is among nine coal-fired plants it intends to retire by September 1, 2012, subject to review of reliability impacts by PJM. FirstEnergy is unable to predict the outcome of this matter or estimate the possible loss or range of loss.

In January 2010, the WVDEP issued a NOV for opacity emissions at the Pleasants coal-fired plant. In August 2011, FirstEnergy and WVDEP resolved the NOV through a Consent Order requiring installation of a reagent injection system to reduce opacity by September 2012.

National Ambient Air Quality Standards

The EPA's CAIR requires reductions of NOx and SO_2 emissions in two phases (2009/2010 and 2015), ultimately capping SO_2

emissions in affected states to 2.5 million tons annually and NOx emissions to 1.3 million tons annually. In 2008, the U.S. Court of Appeals for the District of Columbia 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 CSAPR, to replace CAIR,requiring reductions of NOx and SO_2 emissions in two phases (2012 and 2014), ultimately capping SO_2 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. On February 21, 2012, the EPA revised certain CASPR state budgets (for Florida, Louisiana, Michigan, Mississippi, Nebraska, New Jersey, New York, Texas, and Wisconsin and new unit set-asides in Arkansas and Texas), certain generating unit allocations (for some units in Alabama, Indiana, Kansas, Kentucky, Ohio and Tennessee) for NOx and SO_2 emissions and delayed from 2012 to 2014 certain allowance penalties that could apply with respect to interstate trading of NOx and SO_2 emission allowances. On December 30, 2011, CSAPR was stayed by the U.S. Court of Appeals for the District of Columbia Circuit pending a decision on legal challenges raised in appeals filed by various stakeholders and scheduled to be argued before the Court on April 13, 2012. The Court ordered EPA to continue administration of CAIR until the Court resolves the CSAPR appeals. Depending on the outcome of these proceedings and how any final rules are ultimately implemented, FGCO's and AE Supply's future cost of compliance may be substantial and changes to FirstEnergy's operations may result.

During 2011, FirstEnergy recorded pre-tax impairment charges of approximately \$6 million (\$1 million for FES and \$5 million for AE Supply) for NOx emission allowances that were expected to be obsolete after 2011 and approximately \$21 million (\$18 million for FES and \$3 million for AE Supply) for excess SO_2 emission allowances in inventory that it expects will not be consumed in the future.

Hazardous Air Pollutant Emissions

On December 21, 2011, the EPA finalized the MATS to establish emission standards for mercury, hydrochloric acid and various metals for electric generating units. The MATS establishes emission limits for mercury, PM, and HCL for all existing and new coal-fired electric generating units effective in April 2015 and allows averaging of emissions from multiple units located at a single plant. Under the CAA, state permitting authorities can grant an additional compliance year through April 2016, as needed, including instances when necessary to maintain reliability where electric generating units are being closed. In addition, an EPA enforcement policy document contemplates up to an additional year to achieve compliance, through April 2017, under certain circumstances for reliability critical units.

On January 26, 2012 and February 8, 2012, FGCO, MP and AE Supply announced the retirement by September 1, 2012 (subject to a reliability review by PJM) of nine coal-fired power plants (Albright, Armstrong, Ashtabula, Bay Shore except for generating unit 1, Eastlake, Lake Shore, R. Paul Smith, Rivesville and Willow Island) with a total capacity of 3,349 megawatts (generating, on average, approximately ten percent of the electricity produced by the companies over the past three years) due to MATS and other environmental regulations. In addition, MP will make a filing with the WVPSC to provide them with information regarding the retirement of its plants. Depending on how the MATS are ultimately implemented, FirstEnergy's future cost of compliance with MATS may be substantial and other changes to FirstEnergy's operations may result.

On February 24, 2012, PJM notified FirstEnergy of its preliminary analysis of the reliability impacts that may result from closure of the older competitive coal-fired generating units. PJM's preliminary analysis indicated that there would be significant reliability concerns that will need to be addressed. FirstEnergy intends to continue to actively engage in discussions with PJM regarding this notification, including the possible continued operation of certain plants.

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. 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 and report GHG emissions commencing in 2010. 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 of CO_2 equivalents effective January 2, 2011, for existing facilities under the CAA's PSD program.

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 three years with a goal of increasing to $100 billion by 2020; and establishes the “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. A December 2011 U.N. Climate Change Conference in Durban, Africa, established a negotiating process to develop a new post-2020 climate change protocol, called the “Durban Platform for Enhanced Action”. This negotiating process contemplates developed countries, as well as developing countries such as China, India, Brazil, and South Africa, to undertake legally binding commitments post-2020. In addition, certain countries agreed to extend the Kyoto Protocol for a second commitment period, commencing in 2013 and expiring in 2018 or 2020.

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 but failed to answer the question of the extent to which actions for damages based on GHG emissions may remain viable. The Court remanded to the Second Circuit the issue of whether the CAA preempted state common law nuisance actions.

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 CWA 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 CWA 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 CWA 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 CWA 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. 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 CWA 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. On August 5, 2011, EPA issued an information request pursuant to Sections 308 and 311 of the CWA for certain information pertaining to the oil spills and spill prevention measures at FirstEnergy facilities. FirstEnergy responded on October 10, 2011. On February 1, 2012, FirstEnergy executed a tolling agreement with the EPA extending the statute of limitations to July 31, 2012. FGCO does not anticipate any losses resulting from this matter to be material.

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 impoundments at the Albright Station seeking unspecified civil penalties and injunctive relief. The MP filed an answer on July 11, 2011, and a motion to stay the proceedings on July 13, 2011. On January 3, 2012, the Court denied MP's motion to dismiss or stay the CWA citizen suit but without prejudice to re-filing in the future. 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 a 60-Day Notice of Intent required prior to filing a citizen suit under the CWA for alleged failure to obtain a permit to construct the fly ash impoundments at the Albright Plant.

FirstEnergy intends to vigorously defend against the CWA matters described above but, except as indicated above, cannot predict their outcomes or estimate the possible loss or range of loss.

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 coal-fired Hatfield's Ferry 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 estimated costs in excess of $150 million in order to install technology to meet TDS and sulfate limits in the permit or negatively affect its ability to operate the scrubbers as designed. 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. A hearing on the parties' appeals was 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, and has rescheduled a hearing, if necessary, for July 2012. If these settlement discussions are successful, AE Supply anticipates that its obligations will not be material. AE Supply intends to vigorously pursue these issues, but cannot predict the outcome of these appeals or estimate the possible loss or range of loss.

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 CWA 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 the coal-fired Hatfield's Ferry and Mitchell Plants in Pennsylvania and the coal-fired Fort Martin Plant in West Virginia.

In October 2009, the WVDEP issued the water discharge permit for the Fort Martin Plant. Similar to the Hatfield's Ferry water discharge permit, 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 discharge 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 or estimate the possible loss or range of loss.

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 advance 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. Compliance with those regulations could have an adverse impact on FirstEnergy's results of operations and financial condition.
LBR CCB impoundment is expected to run out of disposal capacity for disposal of CCBs from the BMP between 2016 and 2018. BMP is pursuing several CCB disposal options.
Certain of our utilities 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 December 31, 2011, based on estimates of the total costs of cleanup, the Utility Registrants' proportionate responsibility for such costs and the financial ability of other unaffiliated entities to pay. Total liabilities of approximately $106 million (JCP&L - $70 million, TE - $1 million, CEI - $1 million, FGCO - $1 million and FE - $33 million) have been accrued through December 31, 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 an additional expense of $29 million during the second quarter of 2011; $30 million had previously been reserved prior to 2011. FirstEnergy determined that it is reasonably possible that it or its subsidiaries could be found potentially responsible for additional amounts or additional sites, but the possible losses or range of losses cannot be determined or reasonably estimated at this time.
Fuel Supply
FirstEnergy currently has long-term coal contracts with various terms to acquire approximately 34.5 million tons of coal for the year 2012 which is approximately 90% of its 2012 coal requirements of 38.5 million tons. This coal requirement excludes the impact of our recently announced decision to close nine older coal-fired plants by September 1, 2012, subject to review for reliability impacts by PJM. This contract coal is produced primarily from mines located in Ohio, Pennsylvania, West Virginia, Montana and Wyoming. The contracts expire at various times through December 31, 2030. See “Environmental Matters” for factors pertaining to meeting environmental regulations affecting coal-fired generating units.
FirstEnergy has contracts for all uranium requirements through 2012 and a portion of uranium material requirements through 2024. Conversion services contracts fully cover requirements through 2012 and partially fill requirements through 2024. Enrichment services are contracted for essentially all of the enrichment requirements for nuclear fuel through 2020. A portion of enrichment requirements is also contracted for through 2024. Fabrication services for fuel assemblies are contracted for both Beaver Valley units through 2013 and Davis-Besse through 2025 and through the current operating license period for Perry. In addition to the existing commitments, FirstEnergy intends to make additional arrangements for the supply of uranium and for the subsequent conversion, enrichment, fabrication, and waste disposal services.

On-site spent fuel storage facilities are expected to be adequate for Beaver Valley Unit 1 through 2014. Davis-Besse has adequate storage through 2017. FENOC is taking actions to extend the spent fuel storage capacity for Beaver Valley Units 1 and 2 and Perry. Plant modifications to increase the storage capacity of the existing spent fuel storage pool at Beaver Valley Unit 2 were approved by the NRC on April 29, 2011 and the plant modifications are expected to be complete in 2012. Once this expansion is complete, Beaver Valley Unit 2 will have spent fuel pool storage capacity through 2022. Dry fuel storage is also being pursued at Beaver Valley with completion projected by the end of 2014. Perry dry fuel storage facilities have been completed with the initial dry fuel storage loading campaign targeted for 2012. Both Beaver Valley Unit 2 and Perry maintain sufficient fuel storage capability to continue operations through the targeted completion dates of their respective storage expansion projects. After current on-site storage capacity at the plants is exhausted, additional storage capacity will have to be obtained either through plant modifications, interim off-site disposal, or permanent waste disposal facilities.

The Federal Nuclear Waste Policy Act of 1982 provided for the construction of facilities for the permanent disposal of high-level nuclear wastes, including spent fuel from nuclear power plants operated by electric utilities. NGC has contracts with the DOE for the disposal of spent fuel for Beaver Valley, Davis-Besse and Perry. Yucca Mountain was approved in 2002 as a repository for underground disposal of spent nuclear fuel from nuclear power plants and high level waste from U.S. defense programs. The DOE submitted the license application for Yucca Mountain to the NRC on June 3, 2008. On March 3, 2010, the DOE filed a motion to withdraw its Yucca Mountain license application with prejudice. The ASLB denied the DOE's withdrawal motion on June 29, 2010. On September 9, 2011, the NRC issued an Order (CLI-11-07) stating that it was evenly divided on whether to overturn or uphold the ASLB's decision, and directing the ASLB to complete all necessary and appropriate case management activities by the close of the fiscal year. The current Administration has stated the Yucca Mountain repository will not be completed and a Federal review of potential alternative strategies is being performed. The President's 2011 budget proposal eliminated funding for Yucca Mountain, and the 2011 DOE appropriation did not include any funds for Yucca Mountain. Likewise, the President's 2012 budget proposal does not provide for funding of Yucca Mountain.

In parallel, several parties filed actions in the U.S. Circuit Court of Appeals for the D.C. Circuit challenging the Department's authority to withdraw the license application in light of its obligations under the Nuclear Waste Policy Act. The first case filed was In re: Aiken County, filed on February 19, 2010. Robert L. Ferguson, et al. filed a petition on February 25, 2010; State of South Carolina filed on March 26, 2010; and State of Washington filed on April 13, 2010. These cases have since been consolidated. On May 3, 2010, the D.C. Circuit granted a motion by the National Association of Regulatory Utility Commissioners to intervene. Oral arguments were heard by the D.C. Circuit on March 22, 2011. The D.C. Circuit dismissed the petitions for lack of jurisdiction on July 1, 2011, finding a lack of finality and ripeness until the Commission acts on DOE's motion to withdraw or rules on the license application. In response to the NRC's order from September 2011, the states and other interested parties re-commenced their challenge at the D. C. Circuit, in Aiken County et al., No. 11-1271. Briefing in that appeal was recently completed, and oral argument has been set for May 2, 2012. In light of this uncertainty, FirstEnergy intends to make additional arrangements for storage capacity as a contingency for the continuing delays of the DOE acceptance of spent fuel for disposal.

Fuel oil and natural gas are used primarily to fuel peaking units and/or to ignite the burners prior to burning coal when a coal-fired plant is restarted. Fuel oil requirements have historically been low and are forecasted to remain so. Requirements are expected to average approximately 4 million gallons per year over the next five years. Natural gas is currently consumed primarily by peaking units and demand is forecasted at less than 7 million mcf in 2012.

System Demand

The 2011 maximum hourly demand for each of the Utilities was:

- OE—6,070 MW on July 21, 2011;
- Penn—1,048 MW on July 21, 2011;
- CEI—4,648 MW on July 21, 2011;
- TE—2,286 MW on July 21, 2011;
- JCP&L—6,588 MW on July 22, 2011;
- Met-Ed—3,094 MW on July 22, 2011;
- Penelec—3,128 MW on July 22, 2011;
- MP—1,989 MW on July 21, 2011;
- PE—2,969 MW on July 21, 2011; and
- WP—4,017 MW on July 21, 2011

Supply Plan

Regulated Commodity Sourcing

Certain of the Utilities have default service obligations to provide power to non-shopping customers who have elected to continue to receive service under regulated retail tariffs. The volume of these sales can vary depending on the level of shopping that occurs. Supply plans vary by state and by service territory. JCP&L's default service or BGS supply is secured through a statewide competitive procurement process approved by the NJBPU. The Ohio Companies', Pennsylvania Companies' and PE's Maryland default service supplies are provided through a competitive procurement process approved by the PUCO (under the ESP), PPUC (under the DSP) and MDPSC (under the SOS), respectively. If any supplier fails to deliver power to any one of those Utilities' service areas, the Utility serving that area may need to procure the required power in the market in their role as a POLR. West Virginia electric generation continues to be regulated by the WVPSC.

Unregulated Commodity Sourcing

The Competitive Energy Services segment, through FES and AE Supply, provides energy and energy related services, including the generation and sale of electricity and energy planning and procurement through retail and wholesale competitive supply arrangements. FES supplies the power requirements of its competitive load-serving obligations through a combination of subsidiary-owned generation, non-affiliated contracts and spot market transactions.

FES and AE Supply have retail and wholesale competitive load-serving obligations in Ohio, Pennsylvania, Illinois, Maryland, Michigan and New Jersey, serving both affiliated and non-affiliated companies. FES and AE Supply provide energy products and services to customers under various POLR, shopping, competitive-bid and non-affiliated contractual obligations. Geographically, most of FES' and AE Supply's obligations are in the PJM market area where all of its respective generation facilities are located.

Regional Reliability

All of FirstEnergy's facilities are located within PJM and operate under the reliability oversight of a regional entity known as RFC. This regional entity operates under the oversight of the NERC in accordance with a Delegation Agreement approved by the FERC. RFC began operations under the NERC on January 1, 2006. On July 20, 2006, the NERC was certified by the FERC as the ERO in the United States pursuant to Section 215 of the FPA and RFC was certified as a regional entity.

Competition

As a result of actions taken by state legislative bodies, major changes in the electric utility business have occurred in portions of the United States, including Ohio, New Jersey, Pennsylvania and Maryland, where most of FirstEnergy utility subsidiaries operate. These changes have altered the way traditional integrated utilities conduct their business. FirstEnergy has aligned its business units to participate in the competitive electricity marketplace (see Management's Discussion and Analysis for more information regarding FirstEnergy's Competitive Energy Services segment). FirstEnergy's Competitive Energy Services segment participates in deregulated energy markets in Ohio, Pennsylvania, Maryland, Michigan, New Jersey and Illinois, through FES and AE Supply. In these markets, the Competitive Energy Services segment competes: (1) to provide retail generation service directly to end users; (2) to provide wholesale generation service to utilities, municipalities and co-operatives, which, in turn, resell to their end users, and (3) in the wholesale market. The success of the Competitive Energy Services segment is driven by its ability to successfully compete against other retail markets and/or generators and to produce revenues that exceed costs.

Seasonality

The sale of electric power is generally a seasonal business and weather patterns can have a material impact on FirstEnergy’s operating results. Demand for electricity in our service territories historically peaks during the summer and winter months, with market prices also generally peaking at that time. Accordingly, FirstEnergy’s annual results of operations and liquidity position may depend disproportionately on its operating performance during the summer and winter. Mild weather conditions may result in lower power sales and consequently lower earnings.

Research and Development

The Utilities, FES, FGCO and FENOC participate in the funding of EPRI, which was formed for the purpose of expanding electric R&D under the voluntary sponsorship of the nation’s electric utility industry — public, private and cooperative. Its goal is to mutually benefit utilities and their customers by promoting the development of new and improved technologies to help the utility industry meet present and future electric energy needs in environmentally and economically acceptable ways. EPRI conducts research on all aspects of electric power production and use, including fuels, generation, delivery, energy management and conservation, environmental effects and energy analysis. The majority of EPRI’s research and development projects are directed toward practical solutions and their applications to problems currently facing the electric utility industry.

FirstEnergy participates in other initiatives with industry R&D consortiums and universities to address technology needs for its various business units. Participation in these consortiums helps the company address research needs in areas such as plant operations and maintenance, major component reliability, environmental controls, advanced energy technologies, and transmission and distribution system infrastructure to improve performance, and develop new technologies for advanced energy and grid applications.

Executive Officers

Name	Age	Positions Held During Past Five Years	Dates
A. J. Alexander	60	President and Chief Executive Officer (A)(B)	*-present
		Chief Executive Officer (F)	*-present
		President and Chief Executive Officer (H)	2011-present
		President (C)(D)	*-2008
L. M. Cavalier	60	Senior Vice President, Human Resources (B)	*-present
		Senior Vice President, Human Resources (H)	2011-present
M. T. Clark	61	President and Chief Financial Officer (G)(L)	2012-present
		Executive Vice President and Chief Financial Officer (A)(B)(C)(D)(E)(F)	2009-present
		Executive Vice President and Chief Financial Officer (H)(I)(J)(K)	2011-present
		Executive Vice President and Chief Financial Officer (G)	2011
		Executive Vice President, Strategic Planning & Operations (A)(B)	2008-2009
		Senior Vice President, Strategic Planning & Operations (B)	*-2008
M. J. Dowling	47	Senior Vice President, External Affairs (B)(H)	2011-present
		Vice President, External Affairs (B)	2010-2011
		Vice President, Communications (B)	2008-2010
		Vice President, Governmental Affairs (B)	2007-2008
		Vice President (B)	*-2007
C. E. Jones	56	Senior Vice President & President, FirstEnergy Utilities (B)	2010-present
		Senior Vice President & President, FirstEnergy Utilities (H)	2011-present
		President (J)(K)	2011-present
		President (C)(D)	2010-present
		Senior Vice President & President, FirstEnergy Utilities (A)	2010-2011
		Senior Vice President, Energy Delivery & Customer Service (B)	2009-2010
		President (E)	2007-2009
		Senior Vice President (B)(C)(D)	*-2007
J. H. Lash	61	President FE, Generation (B)(H)	2011-present
		Chief Nuclear Officer (F)	2011-present
		President (I)	2011-present
		President and Chief Nuclear Officer (F)	2010-2011
		Senior Vice President and Chief Operating Officer (F)	2007-2010
		Vice President, Beaver Valley (F)	*-2007
G. R. Leidich	61	Executive Vice President, Integration (A)(B)(H)(M)	2011
		President (G)(M)	2011
		Executive Vice President & President, FirstEnergy Generation (A)(B)(M)	2008-2011
		Senior Vice President, Operations (B)	2007-2008
		President and Chief Nuclear Officer (F)	*-2007
J. F. Pearson	57	Vice President and Treasurer (A)(B)(C)(D)(E)(F)	*-present
		Vice President and Treasurer (G)(H)(I)(J)(K)	2011-present

D. R. Schneider	50	President (E)	2009-present
		Senior Vice President, Energy Delivery & Customer Service (B)	2007-2009
		Senior Vice President (C)(D)	2007-2009
		Vice President (B)	*-2007
L. L. Vespoli	52	Executive Vice President and General Counsel (A)(B)(C)(D)(E)(F)	2008-present
		Executive Vice President and General Counsel (G)(H)(I)(J)(K)	2011-present
		Senior Vice President and General Counsel (A)(B)(C)(D)(E)(F)	*-2008
H. L. Wagner	59	Vice President, Controller and Chief Accounting Officer (A)	*-present
		Vice President and Controller (C)(D)(E)(F)	*-present
		Vice President and Controller (G)(I)(J)(K)	2011-present
		Vice President, Controller and Chief Accounting Officer (H)	2011-present
		Vice President, Controller and Chief Accounting Officer (B)	2010-present
		Vice President and Controller (B)	*-2010

* Indicates position held at least since January 1, 2007

(A) Denotes executive officer of FE

(B) Denotes executive officer of FESC

(C) Denotes executive officer of OE, CEI and TE

(D) Denotes executive officer of Met-Ed, Penelec and Penn

(E) Denotes executive officer of FES

(F) Denotes executive officer of FENOC

(G) Denotes executive officer of AE

(H) Denotes executive officer of AESC

(I) Denotes executive officer of AGC

(J) Denotes executive officer of MP, PE and WP

(K) Denotes executive officer of TrAIL

(L) Position effective January 1, 2012

(M) Retired on December 31, 2011

Employees

As of December 31, 2011, FirstEnergy's subsidiaries had 17,257 employees located in the United States as follows:

	Total Employees	Bargaining Unit Employees
FESC	2,975	293
AESC[(1)]	3,971	1,177
OE	1,222	714
CEI	897	608
TE	390	290
Penn	204	153
JCP&L	1,413	1,090
Met-Ed	678	488
Penelec	896	638
ATSI	38	—
FES	273	—
FGCO	1,652	1,061
FENOC	2,648	957
Total	17,257	7,469

(1) AESC employs substantially all of the former Allegheny personnel who provide services to AE and its subsidiaries, including AE Supply, AGC, MP, PE, WP and TrAIL.

FirstEnergy Web Site

Each of the registrant's Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, and amendments to those reports filed with or furnished to the SEC pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 are also made available free of charge on or through FirstEnergy's internet 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, we routinely post important information on our Web site and recognize our 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 the SEC's Regulation FD. Information contained on FirstEnergy's Web site shall not be deemed incorporated into, or to be part of, this report.

In accordance with SEC rules, FirstEnergy will include disclosure of any amendment or waiver to its Code of Ethics or a provision of that Code on its Internet Web site within four business days following the date of any such amendment or waiver.

ITEM 1A. RISK FACTORS

We operate in a business environment that involves significant risks, many of which are beyond our control. Management of each Registrant regularly evaluates the most significant risks of the Registrant's businesses and reviews those risks with the FirstEnergy Board of Directors or appropriate Committees of the Board. The following risk factors and all other information contained in this report should be considered carefully when evaluating FirstEnergy and our subsidiaries. These risk factors could affect our financial results and cause such results to differ materially from those expressed in any forward-looking statements made by or on behalf of us. Below, we have identified risks we currently consider material. Additional information on risk factors is included in "Item 1. Business" and "Item 7. Management's Discussion and Analysis of Registrant and Subsidiaries" and in other sections of this Form 10-K that include forward-looking and other statements involving risks and uncertainties that could impact our business and financial results.

Risks Related to Business Operations

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

Operation of generation, transmission and distribution facilities involves risk, including the risk of potential breakdown or failure of equipment or processes due to aging infrastructure, fuel supply or transportation disruptions, accidents, labor disputes or work stoppages by employees, acts of terrorism or sabotage, construction delays or cost overruns, shortages of or delays in obtaining equipment, material and labor, operational restrictions resulting from environmental limitations and governmental interventions, and performance below expected levels. In addition, weather-related incidents and other natural disasters can disrupt generation, transmission and distribution delivery systems. Because our transmission facilities are interconnected with those of third parties, the operation of our facilities could be adversely affected by unexpected or uncontrollable events occurring on the systems of such third parties.

Operation of our power plants below expected capacity could result in lost revenues and increased expenses, including higher operating and maintenance costs, purchased power costs and capital requirements. Unplanned outages of generating units and extensions of scheduled outages due to mechanical failures or other problems occur from time to time and are an inherent risk of our business. Unplanned outages typically increase our operation and maintenance expenses and may reduce our revenues as a result of selling fewer MWH or may require us to incur significant costs as a result of operating our higher cost units or obtaining replacement power from third parties in the open market to satisfy our forward power sales obligations. Moreover, if we were unable to perform under contractual obligations, penalties or liability for damages could result.

FES, FGCO and the Ohio Companies are exposed to losses under their applicable sale-leaseback arrangements for generating facilities upon the occurrence of certain contingent events that could render those facilities worthless. Although we believe these types of events are unlikely to occur, FES, FGCO and the Ohio Companies have a maximum exposure to loss under those provisions of approximately $1.4 billion for FES, $606 million for OE and an aggregate of $587 million for TE and CEI as co-lessees.

We remain obligated to provide safe and reliable service to customers within our franchised service territories. Meeting this commitment requires the expenditure of significant capital resources. Failure to provide safe and reliable service and failure to meet regulatory reliability standards due to a number of factors, including, but not limited to, equipment failure and weather, could adversely affect our operating results through reduced revenues and increased capital and operating costs and the imposition of penalties/fines or other adverse regulatory outcomes.

Changes in Commodity Prices Could Adversely Affect Our Profit Margins

We purchase and sell electricity in the competitive wholesale and retail markets. Increases in the costs of fuel for our generation facilities (particularly coal, uranium and natural gas) can affect our profit margins. Changes in the market price of electricity, which are affected by changes in other commodity costs and other factors, may impact our results of operations and financial position by increasing the amount we pay to purchase power to supply POLR and default service obligations in the states we do business. In addition, the global economy could lead to lower international demand for coal, oil and natural gas, which may lower fossil fuel prices and put downward pressure on electricity prices.

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

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

We Are Exposed to Operational, Price and Credit Risks Associated With Selling and Marketing Products in the Power Markets That We Do Not Always Completely Hedge Against

We purchase and sell power at the wholesale level under market-based tariffs authorized by the FERC, and also enter into agreements to sell available energy and capacity from our generation assets. If we are unable to deliver firm capacity and energy under these agreements, we may be required to pay damages. These damages would generally be based on the difference between the market price to acquire replacement capacity or energy and the contract price of the undelivered capacity or energy. Depending on price volatility in the wholesale energy markets, such damages could be significant. Extreme weather conditions, unplanned power plant outages, transmission disruptions, and other factors could affect our ability to meet our obligations, or cause increases in the market price of replacement capacity and energy.

We attempt to mitigate risks associated with satisfying our contractual power sales arrangements by reserving generation capacity to deliver electricity to satisfy our net firm sales contracts and, when necessary, by purchasing firm transmission service. We also routinely enter into contracts, such as fuel and power purchase and sale commitments, to hedge our exposure to fuel requirements and other energy-related commodities. We may not, however, hedge the entire exposure of our operations from commodity price volatility. To the extent we do not hedge against commodity price volatility, our results of operations and financial position could be negatively affected.

The Use of Derivative Contracts by Us to Mitigate Risks Could Result in Financial Losses That May Negatively Impact Our Financial Results

We use a variety of non-derivative and derivative instruments, such as swaps, options, futures and forwards, to manage our commodity and financial market risks. In the absence of actively quoted market prices and pricing information from external sources, the valuation of some of these derivative instruments involves management's judgment or use of estimates. As a result, changes in the underlying assumptions or use of alternative valuation methods could affect the reported fair value of some of these contracts. Also, we could recognize financial losses as a result of volatility in the market values of these contracts or if a counterparty fails to perform.

Financial Derivatives Reforms Could Increase Our Liquidity Needs and Collateral Costs and Impose Additional Regulatory Burdens

In July 2010, federal legislation was enacted to reform financial markets that significantly alter how OTC derivatives are regulated. The Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank) increased regulatory oversight of OTC derivatives, including (1) requiring standardized OTC derivatives to be traded on registered exchanges regulated by the CFTC, (2) imposing new and potentially higher capital and margin requirements and (3) authorizing the establishment of overall volume and position limits. The law gives the CFTC authority to exempt companies that participate in the swap market as "end users" for hedging purposes which could reduce, but not eliminate, the applicability of these measures to us. These requirements could cause our OTC transactions to be more costly and have an adverse effect on our liquidity due to additional capital requirements. In addition, as these reforms aim to standardize OTC products it could limit the effectiveness of our hedging programs because we would have less ability to tailor OTC derivatives to match the precise risk we are seeking to protect.

We rely on the OTC derivative markets as part of our program to hedge the price risk associated with our power portfolio. The effect on our operations of this legislation will depend in part on whether we are determined to be a swap dealer, a major swap participant or a qualifying end-user through a self-identification process, based on the meaning of those terms to be established in the final rules. If we are determined to be a swap dealer or a major swap participant, we will be required to register with the CFTC and execute most bilateral OTC derivative transactions through an exchange or central clearinghouse. This requirement could require us to commit substantial additional capital to cover increases in collateral costs associated with margin requirements of the major exchanges. We would also be required to comply with increased reporting and record-keeping requirements and follow CFTC-specified business conduct standards, and adhere to position limits in a potentially broad range of energy commodities.

Even if we are not determined to be a swap dealer or a major swap participant, we will be required to comply with additional regulatory obligations under Dodd-Frank, which includes some reporting requirements, clearing some additional transactions that we would otherwise enter into over-the-counter, and having to adhere to position limits. Also, the total burden that the rules could impose on all market participants could cause liquidity in the bilateral OTC swap market to decrease substantially. The new rules could impede our ability to meet our hedge targets in a cost-effective manner. FirstEnergy cannot predict the ultimate outcome that Dodd-Frank will have on its results of operations, cash flows or financial position.

Our Risk Management Policies Relating to Energy and Fuel Prices, and Counterparty Credit, Are by Their Very Nature Risk Related, and We Could Suffer Economic Losses Despite Such Policies

We attempt to mitigate the market risk inherent in our energy, fuel and debt positions. Procedures have been implemented to enhance and monitor compliance with our risk management policies, including validation of transaction and market prices, verification of risk and transaction limits, sensitivity analysis and daily portfolio reporting of various risk measurement metrics. Nonetheless, we cannot economically hedge all of our exposures in these areas and our risk management program may not operate as planned. For example, actual electricity and fuel prices may be significantly different or more volatile than the historical trends and assumptions reflected in our analyses. Also, our power plants might not produce the expected amount of power during a given day or time period due to weather conditions, technical problems or other unanticipated events, which could require us to make energy purchases at higher prices than the prices under our energy supply contracts. In addition, the amount of fuel required for our power plants during a given day or time period could be more than expected, which could require us to buy additional fuel at prices less favorable than the prices under our fuel contracts. As a result, we cannot always predict the impact that our risk management decisions may have on us if actual events lead to greater losses or costs than our risk management positions were intended to hedge.

Our risk management activities, including our power sales agreements with counterparties, rely on projections that depend heavily on judgments and assumptions by management of factors such as future market prices and demand for power and other energy-related commodities. These factors become more difficult to predict and the calculations become less reliable the further into the future these estimates are made. Even when our policies and procedures are followed and decisions are made based on these estimates, results of operations may be diminished if the judgments and assumptions underlying those calculations prove to be inaccurate.

We also face credit risks from parties with whom we contract who could default in their performance, in which cases we could be forced to sell our power into a lower-priced market or make purchases in a higher-priced market than existed at the time of executing the contract. Although we have established risk management policies and programs, including credit policies to evaluate counterparty credit risk, there can be no assurance that we will be able to fully meet our obligations, that we will not be required to pay damages for failure to perform or that we will not experience counterparty non-performance or that we will collect for voided contracts. If counterparties to these arrangements fail to perform, we may be forced to enter into alternative hedging arrangements or honor underlying commitments at then-current market prices. In that event, our financial results could be adversely affected.

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

We are subject to the risks of nuclear generation, including but not limited to the following:

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

The NRC has broad authority under federal law to impose licensing security and safety-related requirements for the operation of nuclear generation facilities. In the event of non-compliance, the NRC has the authority to impose fines and/or shut down a unit, depending upon its assessment of the severity of the situation, until compliance is achieved. Revised safety requirements promulgated by the NRC could necessitate substantial capital expenditures at nuclear plants, including ours. Also, a serious nuclear incident at a nuclear facility anywhere in the world could cause the NRC to limit or prohibit the operation or relicensing of any domestic nuclear unit. See "Potential NRC Regulation in Response to the Incident at Japan's Fukushima Daiichi Nuclear Plant Could Adversely Effect Our Business and Financial Condition" below and Note 16, Commitments, Guarantees and Contingencies - Environmental Matters of the Combined Notes to the Consolidated Financial Statements.

We Have a Significant Percentage of Coal-Fired Generation Capacity Which Exposes us to Risk from Regulations Relating to Coal and Coal Combustion Residuals

Approximately 65% of FirstEnergy's generation fleet capacity is coal-fired. Historically, coal-fired generating plants face greater exposure to the costs of complying with federal, state and local environmental statutes, rules and regulations relating to emissions of SO_2 and NOx. In addition, the MATS established coal-fired emission standards for mercury, hydrochloric acid and various metals effective in April 2015, proposed coal combustion residual regulations include an option to reclassify coal ash as a hazardous waste, and there are currently a number of federal, state and international initiatives under consideration to, among other things, require reductions in GHG emissions. These legal requirements and initiatives could require substantial additional costs, extensive mitigation efforts and, in the case of GHG requirements, could raise uncertainty about the future viability of fossil fuels, particularly coal, as an energy source for new and existing electric generation facilities. Failure to comply with any such existing or future legal requirements may also result in the assessment of fines and penalties. Significant resources also may be expended to defend against allegations of violations of any such requirements.

Capital Market Performance and Other Changes May Decrease the Value of Pension Fund Assets, Decommissioning and Other Trust Funds Which Then Could Require Significant Additional Funding

Our financial statements reflect the values of the assets held in trust to satisfy our obligations to decommission our nuclear generation facilities and under pension and other postemployment benefit plans. The value of certain of the assets held in these trusts do not have readily determinable market values. Changes in the estimates and assumptions inherent in the value of these assets could affect the value of the trusts. If the value of the assets held by the trusts declines by a material amount, our funding obligation to the trusts could materially increase. These assets are subject to market fluctuations and will yield uncertain returns, which may fall below our projected return rates. Forecasting investment earnings and costs to decommission nuclear generating stations, to pay future pensions and other obligations requires significant judgment, and actual results may differ significantly from current estimates. Capital market conditions that generate investment losses or increase the present value of liabilities can negatively impact our results of operations and financial position.

We Could be Subject to Higher Costs and/or Penalties Related to Mandatory Reliability Standards Set by NERC/FERC or Changes in the Rules of Organized Markets and the States in Which We Do Business

As a result of the EPACT, owners, operators, and users of the bulk electric system are subject to mandatory reliability standards promulgated by the NERC and approved by FERC as well as mandatory reliability standards and energy efficiency requirements imposed by each of the states in which we operate. The standards are based on the functions that need to be performed to ensure that the bulk electric system operates reliably. Compliance with modified or new reliability standards may subject us to higher operating costs and/or increased capital expenditures. If we were found not to be in compliance with the mandatory reliability standards, we could be subject to sanctions, including substantial monetary penalties.

Reliability standards that were historically subject to voluntary compliance are now mandatory and could subject us to potential civil penalties for violations which could negatively impact our business. The FERC can now impose penalties of $1.0 million per day for failure to comply with these mandatory electric reliability standards.

In addition to direct regulation by the FERC and the states, we are also subject to rules and terms of participation imposed and administered by various RTOs and ISOs. Although these entities are themselves ultimately regulated by the FERC, they can impose rules, restrictions and terms of service that are quasi-regulatory in nature and can have a material adverse impact on our business. For example, the independent market monitors of ISOs and RTOs may impose bidding and scheduling rules to curb the potential exercise of market power and to ensure the market functions. Such actions may materially affect our ability to sell, and the price we receive for, our energy and capacity. In addition, the RTOs may direct our transmission owning affiliates to build new transmission facilities to meet the reliability requirements of the RTO or to provide new or expanded transmission service under the RTO tariffs.

We Rely on Transmission and Distribution Assets That We Do Not Own or Control to Deliver Our Wholesale Electricity. If Transmission is Disrupted, Including Our Own Transmission, or Not Operated Efficiently, or if Capacity is Inadequate, Our Ability to Sell and Deliver Power May Be Hindered

We depend on transmission and distribution facilities owned and operated by utilities and other energy companies to deliver the electricity we sell. If transmission is disrupted (as a result of weather, natural disasters or other reasons) or not operated efficiently by ISOs, in applicable markets, or if capacity is inadequate, our ability to sell and deliver products and satisfy our contractual obligations may be hindered, or we may be unable to sell products on the most favorable terms. In addition, in certain of the markets in which we operate, we may be required to pay for congestion costs if we schedule delivery of power between congestion zones during periods of high demand. If we are unable to hedge or recover for such congestion costs in retail rates, our financial results could be adversely affected.

Demand for electricity within our Utilities’ service areas could stress available transmission capacity requiring alternative routing or curtailing electricity usage that may increase operating costs or reduce revenues with adverse impacts to our results of operations. In addition, as with all utilities, potential concerns over transmission capacity could result in MISO, PJM or the FERC requiring us to upgrade or expand our transmission system, requiring additional capital expenditures.

The FERC requires wholesale electric transmission services to be offered on an open-access, non-discriminatory basis. Although these regulations are designed to encourage competition in wholesale market transactions for electricity, it is possible that fair and equal access to transmission systems will not be available or that sufficient transmission capacity will not be available to transmit electricity as we desire. We cannot predict the timing of industry changes as a result of these initiatives or the adequacy of transmission facilities in specific markets or whether independent system operators in applicable markets will operate the transmission networks, and provide related services, efficiently.

Disruptions in Our Fuel Supplies or Changes in Our Fuel Needs Could Occur, Which Could Adversely Affect Our Ability to Operate Our Generation Facilities or Impact Financial Results

We purchase fuel from a number of suppliers. The lack of availability of fuel at expected prices, or a disruption in the delivery of fuel which exceeds the duration of our on-site fuel inventories, including disruptions as a result of weather, increased transportation costs or other difficulties, labor relations or environmental or other regulations affecting our fuel suppliers, could cause an adverse impact on our ability to operate our facilities, possibly resulting in lower sales and/or higher costs and thereby adversely affect our results of operations. Operation of our coal-fired generation facilities is highly dependent on our ability to procure coal. We have long-term contracts in place for a majority of our coal and coal transportation needs. We may from time to time enter into new, or renegotiate certain of these contracts, but can provide no assurance that such contracts will be negotiated or renegotiated, as the case may be, on satisfactory terms, or at all. In addition, if prices for physical delivery are unfavorable, our financial condition, results of operations and cash flows could be materially adversely affected.

Temperature Variations as well as Weather Conditions or other Natural Disasters Could Have a Negative Impact on Our Results of Operations and Demand Significantly Below or Above Our Forecasts Could Adversely Affect Our Energy Margins

Weather conditions directly influence the demand for electric power. Demand for power generally peaks during the summer and winter months, with market prices also typically peaking at that time. Overall operating results may fluctuate based on weather conditions. In addition, we have historically sold less power, and consequently received less revenue, when weather conditions are milder. Severe weather, such as tornadoes, hurricanes, ice or snowstorms, or droughts or other natural disasters, may cause outages and property damage that may require us to incur additional costs that are generally not insured and that may not be recoverable from customers. The effect of the failure of our facilities to operate as planned under these conditions would be particularly burdensome during a peak demand period. Customer demand could change as a result of severe weather conditions or other circumstances over which we have no control. We satisfy our electricity supply obligations through a portfolio approach of providing electricity from our generation assets, contractual relationships and market purchases. A significant increase in demand could adversely affect our energy margins if we are required to provide the energy supply to fulfill this increased demand at fixed rates, which we expect would remain below the wholesale prices at which we would have to purchase the additional supply if needed or, if we had available capacity, the prices at which we could otherwise sell the additional supply. Accordingly, any significant change in demand could have a material adverse effect on our results of operations and financial position.

We Are Subject to Financial Performance Risks Related to Regional and General Economic Cycles and also Related to Heavy Manufacturing Industries such as Automotive and Steel

Our business follows economic cycles. Economic conditions are a determinant of the demand for electricity and declines in the demand for electricity will reduce our revenues. The regional economy in which our Utilities operate is influenced by conditions in automotive, steel and other heavy industries and as these conditions change, our revenues will be impacted. Additionally, the primary market areas of our Competitive Energy Services segment overlap, to a large degree, with our Utilities' territories and hence its revenues are impacted by the same economic conditions.

Increases in Customer Electric Rates and Economic Uncertainty May Lead to a Greater Amount of Uncollectible Customer Accounts

Our operations are impacted by the economic conditions in our service territories and those conditions could negatively impact the rate of delinquent customer accounts and our collections of accounts receivable which could adversely impact our financial condition, results of operations and cash flows.

We May Recognize Impairments of Recorded Goodwill or of Some of Our Long-Lived Assets, Which Would Result in Write-Offs of the Impaired Amounts

Goodwill could become impaired at one or more of our operating subsidiaries. In addition, one or more of our long-lived assets could become impaired. The actual timing and amounts of any impairments in future years would depend on many factors, including interest rates, sector market performance, our capital structure, market prices for power, results of future rate proceedings, operating and capital expenditure requirements, the value of comparable acquisitions, environmental regulations and other factors.

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

We must find ways to balance the retention of our aging skilled workforce while recruiting new talent to mitigate losses in critical knowledge and skills due to retirements. Mitigating these risks could require additional financial commitments.

Significant Increases in Our Operation and Maintenance Expenses, Including Our Health Care and Pension Costs, Could Adversely Affect Our Future Earnings and Liquidity

We continually focus on limiting, and reducing where possible, our operation and maintenance expenses. We expect to continue to face increased cost pressures in the areas of health care and pension costs. We have experienced significant health care cost inflation in the last few years, and we expect our cash outlay for health care costs, including prescription drug coverage, to continue to increase despite measures that we have taken and expect to take requiring employees and retirees to bear a higher portion of the costs of their health care benefits. The measurement of our expected future health care and pension obligations and costs is highly dependent on a variety of assumptions, many of which relate to factors beyond our control. These assumptions include investment returns, interest rates, health care cost trends, benefit design changes, salary increases, the demographics of plan participants and regulatory requirements. If actual results differ materially from our assumptions, our costs could be significantly increased.

Our Results May be Adversely Affected by the Volatility in Pension and OPEB Expenses.

Effective in 2011, FirstEnergy elected to change its method of recognizing actuarial gains and losses of its pension and OPEB plans. This change will result in the recognition of net actuarial gains or losses, without deferral, in the fourth quarter of each year and whenever a plan is determined to qualify for a remeasurement, may result in greater volatility in pension and OPEB expenses and may materially impact our results of operations under GAAP. For additional information, see Note 1, Organization, Basis of Presentation and Significant Accounting Policies of the Combined Notes to the Consolidated Financial Statements.

Security Breaches, Including Cyber Security Breaches, and Other Disruptions Could Compromise Critical and Proprietary Information and Expose Us to Liability, Which Would Cause our Business and Reputation to Suffer.

In the ordinary course of our business, we store sensitive data, intellectual property and proprietary information regarding our business, employees, customers, suppliers and business partners in our data centers and on our networks. The secure maintenance of this information is critical to our operations. Despite security measures we have employed with respect to this information, our information technology and infrastructure may be vulnerable to attacks by hackers or breached due to employee error, malfeasance or other disruptions. Any such breach could compromise our networks and the information stored there could be accessed, publicly disclosed, lost or stolen. Any such access, disclosure or other loss of information could result in legal claims or proceedings and regulatory penalties. It could also disrupt our business operations and damage our reputation, which could adversely affect our business.

Acts of War or Terrorism Could Negatively Impact Our Business

The possibility that our infrastructure, such as electric generation, transmission and distribution facilities, or that of an interconnected company, could be direct targets of, or indirect casualties of, an act of war or terrorism, could result in disruption of our ability to generate, purchase, transmit or distribute electricity. Any such disruption could result in a decrease in revenues and additional costs to purchase electricity and to replace or repair our assets, which could have a material adverse impact on our results of operations and financial condition.

Capital Improvements and Construction Projects May Not be Completed Within Forecasted Budget, Schedule or Scope Parameters

Our business plan calls for extensive capital investments. We may be exposed to the risk of substantial price increases in the costs of labor and materials used in construction. We engage numerous contractors and enter into a large number of agreements to acquire the necessary materials and/or obtain the required construction-related services. As a result, we are also exposed to the risk that these contractors and other counterparties could breach their obligations to us. Such risk could include our contractors' inabilities to procure sufficient skilled labor as well as potential work stoppages by that labor force. Should the counterparties to these arrangements fail to perform, we may be forced to enter into alternative arrangements at then-current market prices that may exceed our contractual prices, with resulting delays in those and other projects. Although our agreements are designed to mitigate the consequences of a potential default by the counterparty, our actual exposure may be greater than these mitigation provisions. This could have negative financial impacts such as incurring losses or delays in completing construction projects.

Changes in Technology May Significantly Affect Our Generation Business by Making Our Generating Facilities Less Competitive

We primarily generate electricity at large central facilities. This method results in economies of scale and lower costs than newer technologies such as fuel cells, microturbines, windmills and photovoltaic solar cells. It is possible that advances in technologies will reduce their costs to levels that are equal to or below that of most central station electricity production, which could have a material adverse effect on our results of operations.

We May Acquire Assets That Could Present Unanticipated Issues for Our Business in the Future, Which Could Adversely Affect Our Ability to Realize Anticipated Benefits of Those Acquisitions

Asset acquisitions involve a number of risks and challenges, including: management attention; integration with existing assets; difficulty in evaluating the requirements associated with the assets prior to acquisition, operating costs, potential environmental and other liabilities, and other factors beyond our control; and an increase in our expenses and working capital requirements. Any of these factors could adversely affect our ability to achieve anticipated levels of cash flows or realize other anticipated benefits from any such asset acquisition.

Ability of Certain FirstEnergy Companies to Meet Their Obligations to or on behalf of Other FirstEnergy Companies or their Affiliates

Certain of the FirstEnergy companies have obligations to other FirstEnergy companies because of transactions involving energy, coal, other commodities, services and hedging transactions. If one FirstEnergy entity failed to perform under any of these arrangements, other FirstEnergy entities could incur losses. Their results of operations, financial position, or liquidity could be adversely affected, resulting in the nondefaulting FirstEnergy entity being unable to meet its obligations to unrelated third parties. Our hedging activities are generally undertaken with a view to overall FirstEnergy exposures. Some FirstEnergy companies may therefore be more or less hedged than if they were to engage in such transactions alone. Also, some companies affiliated with FirstEnergy also provide guarantees to third party creditors on behalf of other FirstEnergy affiliates under transactions of the type described above or under financing transactions. Any failure to perform under such a guarantee by the affiliated FirstEnergy guarantor company or under the underlying transaction by the FirstEnergy company on whose behalf the guarantee was issued could have similar adverse impacts on one or both FirstEnergy companies or their affiliates.

Energy Companies are Subject to Adverse Publicity Which Make Them Vulnerable to Negative Regulatory and Legislative Outcomes

Energy companies, including FirstEnergy's utility subsidiaries, have been the subject of criticism focused on the reliability of their distribution services and the speed with which they are able to respond to power outages, such as those caused by storm damage. Adverse publicity of this nature, or adverse publicity associated with our nuclear and/or coal-fired facilities may cause less favorable legislative and regulatory outcomes.

Our Merger with AE May Not Achieve Its Intended Results.

We entered into the merger agreement with AE with the expectation that the merger would result in various benefits, including, among other things, cost savings and operating efficiencies relating to the regulated business and the unregulated competitive business. Our ability to achieve the anticipated benefits of the merger is subject to a number of uncertainties, including whether the business and information systems of Allegheny are integrated in an efficient and effective manner. Failure to achieve these anticipated benefits could result in increased costs, decreases in the amount of expected revenues generated by us and diversion of management's time and energy and could have an adverse effect on our business, financial results and prospects. See Part II, Item 7, Management's Discussion and Analysis of Registrant and Subsidiaries for additional information.

Risks Associated With Regulation

Complex and Changing Government Regulations, Including Those Associated With Rates Could Have a Negative Impact on Our Results of Operations

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

Our utility subsidiaries currently provide service at rates approved by one or more regulatory commissions. Thus, the rates a utility is allowed to charge may or may not be set to recover its expenses at any given time. Additionally, there may also be a delay between the timing of when costs are incurred and when costs are recovered. For example, we may be unable to timely recover the costs for our energy efficiency investments, expenses and additional capital or lost revenues resulting from the implementation of aggressive energy efficiency programs. While rate regulation is premised on providing an opportunity to earn a reasonable return on invested capital and recovery of operating expenses, there can be no assurance that the applicable regulatory commission will determine that all of our costs have been prudently incurred or that the regulatory process in which rates are determined will always result in rates that will produce full recovery of our costs in a timely manner.

Regulatory Changes in the Electric Industry, Including a Reversal of, Discontinuance of, or Impediment to the Present Trend Toward Competitive Markets, Could Affect Our Competitive Position and Result in Unrecoverable Costs Adversely Affecting Our Business and Results of Operations

As a result of restructuring initiatives, changes in the electric utility business have occurred, and are continuing to take place throughout the United States, including the states in which we do business. These changes have resulted, and are expected to continue to result, in fundamental alterations in the way utilities conduct their business.

Some states that have deregulated generation service have experienced difficulty in transitioning to market-based pricing. In some instances, state and federal government agencies and other interested parties have made proposals to impose rate cap extensions or otherwise impede market restructuring or even re-regulate areas of these markets that have previously been deregulated. Although we expect wholesale electricity markets to continue to be competitive, proposals to re-regulate our industry may be made, and legislative or other action affecting the electric power restructuring process may cause the process to be delayed, discontinued, restructured or reversed in the states in which we currently, or may in the future, operate. Such delays, discontinuations or reversals of electricity market restructuring in the markets in which we operate could have an adverse impact on our results of operations and financial condition.

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

The Prospect of Rising Rates Could Prompt Legislative or Regulatory Action to Restrict or Control Such Rate Increases. This In Turn Could Create Uncertainty Affecting Planning, Costs and Results of Operations and May Adversely Affect the Utilities' Ability to Recover Their Costs, Maintain Adequate Liquidity and Address Capital Requirements

Increases in utility rates, such as may follow a period of frozen or capped rates, can generate pressure on legislators and regulators to take steps to control those increases. Such efforts can include some form of rate increase moderation, reduction or freeze. The public discourse and debate can increase uncertainty associated with the regulatory process, the level of rates and revenues, and the ability to recover costs. Such uncertainty restricts flexibility and resources, given the need to plan and ensure available financial resources. Such uncertainty also affects the costs of doing business. Such costs could ultimately reduce liquidity, as suppliers tighten payment terms, and increase costs of financing, as lenders demand increased compensation or collateral security to accept such risks.

Our Profitability is Impacted by Our Affiliated Companies' Continued Authorization to Sell Power at Market-Based Rates

The FERC granted certain subsidiaries authority to sell electricity at market-based rates. These orders also granted them waivers of certain FERC accounting, record-keeping and reporting requirements. The FERC's orders that grant this market-based rate authority reserve the right to revoke or revise that authority if the FERC subsequently determines that these companies can exercise market power in transmission or generation, create barriers to entry or engage in abusive affiliate transactions. As a condition to the orders granting the generating companies market-based rate authority, every three years they are required to file a market power update to show that they continue to meet the FERC's standards with respect to generation market power and other criteria used to evaluate whether entities qualify for market-based rates.

There Are Uncertainties Relating to Our Participation in RTOs

RTO rules could affect our ability to sell power produced by our generating facilities to users in certain markets due to transmission

constraints and attendant congestion costs. The prices in day-ahead and real-time energy markets and RTO capacity markets have been subject to price volatility. Administrative costs imposed by RTOs, including the cost of administering energy markets, have also increased. The rules governing the various regional power markets may also change from time to time, which could affect our costs or revenues. To the degree we incur significant additional fees and increased costs to participate in an RTO, and we are limited with respect to recovery of such costs from retail customers, we may suffer financial harm. In addition, we may be allocated a portion of the cost of transmission facilities built by others due to changes in RTO transmission rate design. Finally, we may be required to expand our transmission system according to decisions made by an RTO rather than our internal planning process. As a member of an RTO, we are subject to certain additional risks, including those associated with the allocation among members of losses caused by unreimbursed defaults of other participants in that RTO’s market and those associated with complaint cases filed against the RTO that may seek refunds of revenues previously earned by its members.
Because it remains unclear which companies will be participating in the various regional power markets, or how RTOs will ultimately develop and operate, or what region they will cover, we cannot fully assess the impact that these power markets or other ongoing RTO developments may have.

Energy Conservation and Energy Price Increases Could Negatively Impact Our Financial Results

A number of regulatory and legislative bodies have introduced requirements and/or incentives to reduce energy consumption. Conservation programs could impact our financial results in different ways. To the extent conservation resulted in reduced energy demand or significantly slowed the growth in demand, the value of our competitive generation and other unregulated business activities could be adversely impacted. We currently have energy efficiency riders in place to recover the cost of these programs either at or near a current recovery timeframe in the states we operate. In New Jersey, we recover the costs for energy efficiency programs through the SBC. Currently only Ohio has provisions for recovery of lost revenues. In our regulated operations, conservation could negatively impact us depending on the regulatory treatment of the associated impacts. Should we be required to invest in conservation measures that result in reduced sales from effective conservation, regulatory lag in adjusting rates for the impact of these measures could have a negative financial impact. We could also be impacted if any future energy price increases result in a decrease in customer usage. Our results could be affected if we are unable to increase our customer’s participation in our energy efficiency programs. We are unable to determine what impact, if any, conservation and increases in energy prices will have on our financial condition or results of operations.

Our Business and Activities are Subject to Extensive Environmental Requirements and Could be Adversely Affected by such Requirements

We plan to retire nine older coal-fired generating plants by September 1, 2012, as a result of a comprehensive review of FirstEnergy's coal-fired generating facilities in light of the MATS rules that were recently finalized and other environmental requirements. We may be forced to shut down other facilities, either temporarily or permanently, if we are unable to comply with certain environmental requirements, or if we make a determination that the expenditures required to comply with such requirements are uneconomical.

The EPA is Conducting NSR Investigations at a Number of Generating Plants that We Currently or Formerly Owned, the Results of Which Could Negatively Impact Our Results of Operations and Financial Condition

We may be subject to risks in connection with changing or conflicting interpretations of existing laws and regulations, including, for example, the applicability of EPA's NSR programs . Under the CAA, modification of our generation facilities in a manner that results in increased emissions could subject our existing facilities to the far more stringent NSR standards applicable to new facilities.

The EPA has taken the view that many companies, including many energy producers, have been modifying emissions sources in violation of NSR standards in connection with work considered by the companies to be routine maintenance. We are currently involved in litigation and EPA investigations concerning alleged violations of the NSR standards at certain of our existing and former generating facilities. We intend to vigorously pursue and defend our position but we are unable to predict their outcomes. If NSR and similar requirements are imposed on our generation facilities, in addition to the possible imposition of fines, compliance could entail significant capital investments in pollution control technology, which could have an adverse impact on our business, results of operations, cash flows and financial condition. For a more complete discussion see Note 16, Commitments, Guarantees and Contingencies -

Environmental Matters of the Combined Notes to the Consolidated Financial Statements.

Costs of Compliance with Environmental Laws are Significant, and the Cost of Compliance with Future Environmental Laws, Including Limitations on GHG Emissions, Could Adversely Affect Cash Flow and Profitability

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

There are a number of initiatives to reduce GHG emissions under consideration at the federal, state and international level. Environmental advocacy groups, other organizations and some agencies in the United States and elsewhere are focusing considerable attention on carbon dioxide emissions from power generation facilities and their potential role in climate change. There is a growing consensus in the United States and globally that GHG emissions are a major cause of global warming and that some form of regulation will be forthcoming at the federal level with respect to GHG emissions (including CO_2) and such regulation could result in the creation of substantial additional costs in the form of taxes or emission allowances. As a result, it is possible that state and federal regulations will be developed that will impose more stringent limitations on emissions than are currently in effect. Due to the uncertainty of control technologies available to reduce GHG emissions, including CO_2, as well as the unknown nature of potential compliance obligations should climate change regulations be enacted, we cannot provide any assurance regarding the potential impacts these future regulations would have on our operations. In addition, any legal obligation that would require us to substantially reduce our emissions could require extensive mitigation efforts and, in the case of carbon dioxide legislation, would raise uncertainty about the future viability of fossil fuels, particularly coal, as an energy source for new and existing electric generation facilities. Until specific regulations are issued, the impact that any new environmental regulations, voluntary compliance guidelines, enforcement initiatives, or legislation may have on our results of operations, financial condition or liquidity is not determinable.

FirstEnergy cannot currently estimate the financial impact of certain environmental laws or initiatives including climate change policies, but 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. See Note 16, Commitments, Guarantees and Contingencies - Environmental Matters of the Combined Notes to the Consolidated Financial Statements for a more detailed discussion of the federal, state and international initiatives seeking to reduce emissions of GHG.

We Could be Exposed to Private Rights of Action Seeking Damages Under Various State and Federal Law Theories

Claims have been made against certain energy companies alleging that CO_2 emissions from power generating facilities constitute a public nuisance under federal and/or state common law. As a result, private individuals may seek to enforce environmental laws and regulations against us and could allege personal injury or property damages. While FirstEnergy is not a party to this litigation, it, and/or one of its subsidiaries, could be named in actions making similar allegations. An unfavorable ruling in any such case could have an adverse impact on our results of operations and financial condition and could significantly impact our operations.

Our Costs to Comply with Various Recently Adopted EPA Emission Regulations Could be Substantial and Result in Significant Changes to Our Operations

We are required to comply with recently adopted emission regulations. The EPA's CAIR and CSAPR require reductions of NOx and SO_2 emissions in two phases, ultimately capping SO_2 and NOx emissions in affected states. In July 2011, the EPA finalized the CSAPR (which was stayed in December 2011 pending a decision on various legal challenges) to replace CAIR, which remains in effect until CSAPR becomes effective.

Depending on the outcome of these legal proceedings and how any final rules are ultimately implemented, MP's, FGCO's and AE Supply's future cost of compliance may be substantial and changes to FirstEnergy's operations may result.

Additionally, on December 21, 2011, the EPA finalized the MATS to establish emission standards for, among other things, mercury, hydrochloric acid and various metals for electric generating units. The costs associated with MATS, and other environmental laws, is substantial and led to the Company's recent announcement to retire nine older coal-fired generating units. Depending on how the CSPAR and MATS are ultimately implemented, FirstEnergy's future cost of compliance with such regulations may be substantial and additional changes to FirstEnergy's operations may result. See Note 16, Commitments, Guarantees and Contingencies - Environmental Matters of the Combined Notes to the Consolidated Financial Statements for a more detailed discussion of the above-referenced EPA regulations.

Various Federal and State Water Quality Regulations May Require Us to Make Material Capital Expenditures

The EPA established performance standards under the Clean Water Act which requires the EPA to establish performance standards for reducing impacts on fish and shellfish from cooling water intake structures at certain existing electric generating plants, specifically, 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 2011, the EPA proposed new regulations under the Clean Water Act which generally require fish impingement to be reduced to a 12% annual average and calls for studies to be conducted at the majority of our existing generating facilities to assist permitting authorities to determine whether and what site-specific controls, if any, would be required to reduce entrainment of aquatic life. FirstEnergy is studying the cost and effectiveness of various control options to divert fish away from its plants' cooling water intake system. Depending on the results of such studies and the EPA's further rulemaking and any final action taken by the states, the future costs of compliance with these standards may require material capital expenditures. See Note 16, Commitments, Guarantees and Contingencies - Environmental Matters of the Combined Notes to the Consolidated Financial Statements for a more detailed discussion of the various federal and state water quality regulations listed above.

Compliance with any Coal Combustion Residual Regulations Could Have an Adverse Impact on Our Results of Operations and Financial Condition

We are subject to various federal and state hazardous waste regulations. The EPA has requested comments from the states on options for regulating coal combustion residuals, including whether they should be regulated as hazardous or non-hazardous waste.

The EPA asserted that the large volumes of coal combustion residuals produced by electric utilities pose significant financial risk to the industry and has 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 issued could be substantial and would depend, in part, on the regulatory action taken by the EPA and implementation by the EPA or the states. Compliance with those regulations could have an adverse impact on our results of operations and financial condition.

Remediation of Environmental Contamination at Current or Formerly Owned Facilities

We are subject to liability under environmental laws for the costs of remediating environmental contamination of property now or formerly owned by us and of property contaminated by hazardous substances that we may have generated regardless of whether the liabilities arose before, during or after the time we owned or operated the facilities. Remediation activities associated with our former MGP operations are one source of such costs. We are currently involved in a number of proceedings relating to sites where other hazardous substances have been deposited and may be subject to additional proceedings in the future. We also have current or previous ownership interests in sites associated with the production of gas and the production and delivery of electricity for which we may be liable for additional costs related to investigation, remediation and monitoring of these sites. Citizen groups or others may bring litigation over environmental issues including claims of various types, such as property damage, personal injury, and citizen challenges to compliance decisions on the enforcement of environmental requirements, such as opacity and other air quality standards, which could subject us to penalties, injunctive relief and the cost of litigation. We cannot predict the amount and timing of all future expenditures (including the potential or magnitude of fines or penalties) related to such environmental matters, although we expect that they could be material.

In some cases, a third party who has acquired assets from us has assumed the liability we may otherwise have for environmental matters related to the transferred property. If the transferee fails to discharge the assumed liability or disputes its responsibility, a regulatory authority or injured person could attempt to hold us responsible, and our remedies against the transferee may be limited by the financial resources of the transferee.

We Are and May Become Subject to Legal Claims Arising from the Presence of Asbestos or Other Regulated Substances at Some of Our Facilities

We have been named as a defendant in pending asbestos litigation involving multiple plaintiffs and multiple defendants. In addition, asbestos and other regulated substances are, and may continue to be, present at our facilities where suitable alternative materials are not available. We believe that any remaining asbestos at our facilities is contained. The continued presence of asbestos and other regulated substances at these facilities, however, could result in additional actions being brought against us.

Availability and Cost of Emission Allowances Could Negatively Impact Our Costs of Operations

Although recent court rulings and current conditions have reduced the immediate risk of a negative impact on our operating costs, the uncertainty around CAA programs and requirements continue to be a major concern. We are still required to maintain, either by allocation or purchase, sufficient emission allowances to support our operations in the ordinary course of operating our power generation facilities. These allowances are used to meet our obligations imposed by various applicable environmental laws. If our operational needs require more than our allocated allowances, we may be forced to purchase such allowances on the open market, which could be costly. If we are unable to maintain sufficient emission allowances to match our operational needs, we may have to curtail our operations so as not to exceed our available emission allowances, or install costly new emissions controls. As we use the emissions allowances that we have purchased on the open market, costs associated with such purchases will be recognized as operating expense. If such allowances are available for purchase, but only at significantly higher prices, the purchase of such allowances could materially increase our costs of operations in the affected markets.

Mandatory Renewable Portfolio Requirements Could Negatively Affect Our Costs

If federal or state legislation mandates the use of renewable and alternative fuel sources, such as wind, solar, biomass and geothermal and such legislation would not also provide for adequate cost recovery, it could result in significant changes in our business, including renewable energy credit purchase costs, purchased power and potentially renewable energy credit costs and capital expenditures. We are unable to predict what impact, if any, these changes may have on our financial condition or results of operations.

The Continuing Availability and Operation of Generating Units is Dependent on Retaining or Renewing the Necessary Licenses, Permits, and Operating Authority from Governmental Entities, Including the NRC

We are required to have numerous permits, approvals and certificates from the agencies that regulate our business. We believe the necessary permits, approvals and certificates have been obtained for our existing operations and that our business is conducted in accordance with applicable laws; however, we are unable to predict the impact on our operating results from future regulatory activities of any of these agencies and we are not assured that any such permits, approvals or certifications will be renewed.

Potential NRC Regulation in Response to the Incident at Japan's Fukushima Daiichi Nuclear Plant Could Adversely Effect Our Business and Financial Condition

As a result of the NRC's investigation of the incident at the Fukushima Daiichi nuclear plant, potential exists for the NRC to promulgate new or revised requirements with respect to nuclear plants located in the United States, which could necessitate additional expenditures at our nuclear plants. For example, as a follow up to the NRC near-term Task Force's review and analysis of the Fukushima Daiichi accident, in January 2012, the NRC released an updated seismic risk model that plant operators must use in performing the seismic reevaluations recommended by the task force. These reevaluations could result in the required implementation of additional mitigation strategies or modifications. It is also possible that the NRC could suspend or otherwise delay pending nuclear relicensing proceedings, including the Davis-Besse relicensing proceeding. The impact of any such regulatory actions could adversely affect FirstEnergy's financial condition or results of operations.

The Physical Risks Associated with Climate Change May Impact Our Results of Operations and Cash Flows

Physical risks of climate change, such as more frequent or more extreme weather events, changes in temperature and precipitation patterns, changes to ground and surface water availability, and other related phenomena, could affect some, or all, of our operations. Severe weather or other natural disasters could be destructive, which could result in increased costs, including supply chain costs. An extreme weather event within the Utilities' service areas can also directly affect their capital assets, causing disruption in service to customers due to downed wires and poles or damage to other operating equipment. Finally, climate change could affect the availability of a secure and economical supply of water in some locations, which is essential for continued operation of generating plants.

Future Changes in Accounting Standards May Affect Our Reported Financial Results

The SEC, FASB or other authoritative bodies or governmental entities may issue new pronouncements or new interpretations of existing accounting standards that may require us to change our accounting policies. These changes are beyond our control, can be difficult to predict and could materially impact how we report our financial condition and results of operations. We could be required to apply a new or revised standard retroactively, which could adversely affect our financial position. The SEC announced a work plan to aid in its evaluation of the impact that the use of IFRS by U.S. public companies would have on the U.S. securities market and has identified several potential options to incorporate IFRS in the United States. The SEC expects to announce a more specific course of action in 2012. We continue to monitor the development of the potential implementation of IFRS.

Increases in Taxes and Fees May Adversely Effect Our Results of Operation, Financial Audit and Cash Flow

Due to the revenue needs of the United States and the states and jurisdictions in which we operate, various tax and fee increases may be proposed or considered. We cannot predict whether legislation or regulation will be introduced, the form of any legislation or regulation, whether any such legislation or regulation will be passed by legislatures or regulatory bodies. If enacted, these changes could increase tax costs and could have a negative impact on our results of operations, financial condition and cash flows.

Risks Associated With Financing and Capital Structure

Disruptions in the Capital and Credit Markets May Adversely Affect Our Business, Including the Availability and Cost of Short-Term Funds for Liquidity Requirements, Our Ability to Meet Long-Term Commitments, Our Ability to Hedge Effectively Our Generation Portfolio, and the Competitiveness and Liquidity of Energy Markets; Each Could Adversely Affect Our Results of Operations, Cash Flows and Financial Condition

We rely on the capital markets to meet our financial commitments and short-term liquidity needs if internal funds are not available from our operations. We also use letters of credit provided by various financial institutions to support our hedging operations. Disruptions in the capital and credit markets could adversely affect our ability to draw on our respective credit facilities. Our access to funds under those credit facilities is dependent on the ability of the financial institutions that are parties to the facilities to meet their funding commitments. Those institutions may not be able to meet their funding commitments if they experience shortages of capital and liquidity or if they experience excessive volumes of borrowing requests within a short period of time.

Longer-term disruptions in the capital and credit markets as a result of uncertainty, changing or increased regulation, reduced alternatives or failures of significant financial institutions could adversely affect our access to liquidity needed for our business. Any disruption could require us to take measures to conserve cash until the markets stabilize or until alternative credit arrangements or other funding for our business needs can be arranged. Such measures could include deferring capital expenditures, changing hedging strategies to reduce collateral-posting requirements, and reducing or eliminating future dividend payments or other discretionary uses of cash.

The strength and depth of competition in energy markets depends heavily on active participation by multiple counterparties, which could be adversely affected by disruptions in the capital and credit markets. Reduced capital and liquidity and failures of significant institutions that participate in the energy markets could diminish the liquidity and competitiveness of energy markets that are important to our business. Perceived weaknesses in the competitive strength of the energy markets could lead to pressures for greater regulation of those markets or attempts to replace those market structures with other mechanisms for the sale of power, including the requirement of long-term contracts, which could have a material adverse effect on our results of operations and cash flows.

Interest Rates and/or a Credit Rating Downgrade Could Negatively Affect Our Financing Costs, Our Ability to Access Capital and Our Requirement to Post Collateral

We have near-term exposure to interest rates from outstanding indebtedness indexed to variable interest rates, and we have exposure to future interest rates to the extent we seek to raise debt in the capital markets to meet maturing debt obligations and fund construction or other investment opportunities. Past disruptions in capital and credit markets have resulted in higher interest rates on new publicly issued debt securities, increased costs for certain of our variable interest rate debt securities and failed remarketings of variable interest rate tax-exempt debt issued to finance certain of our facilities. Similar future disruptions could increase our financing costs and adversely affect our results of operations. Also, interest rates could change as a result of economic or other events that our risk management processes were not established to address. As a result, we cannot always predict the impact that our risk management decisions may have on us if actual events lead to greater losses or costs than our risk management positions were intended to hedge. Although we employ risk management techniques to hedge against interest rate volatility, significant and sustained increases in market interest rates could materially increase our financing costs and negatively impact our reported results of operations.

We rely on access to bank and capital markets as sources of liquidity for cash requirements not satisfied by cash from operations. A downgrade in our credit ratings from the nationally recognized credit rating agencies, particularly to a level below investment grade, could negatively affect our ability to access the bank and capital markets, especially in a time of uncertainty in either of those markets, and may require us to post cash collateral to support outstanding commodity positions in the wholesale market, as well as available letters of credit and other guarantees. Furthermore, a downgrade could increase the cost of such capital by causing us to incur higher interest rates and fees associated with such capital. A rating downgrade would also increase the fees we pay on our various existing credit facilities, thus increasing the cost of our working capital. A rating downgrade could also impact our ability to grow our businesses by substantially increasing the cost of, or limiting access to, capital. See Note 16, Commitments, Guarantees and Contingencies - Guarantees and Other Assurances of the Combined Notes to the Consolidated Financial Statements for more information associated with a credit ratings downgrade leading to the posting of cash collateral.

The Soundness of Financial Institutions or Counterparties Could Adversely Affect Us

We have exposure to many different domestic and foreign financial institutions and counterparties and we routinely execute transactions with counterparties in connection with our hedging activities, including brokers and dealers, commercial banks, investment banks and other institutions and industry participants. Many of these transactions expose us to credit risk in the event that any of our lenders or counterparties are unable to honor their commitments or otherwise default under a financing agreement. We also deposit cash balances in short-term investments. Our ability to access our cash quickly depends on the soundness of the financial institutions in which those funds reside. Any delay in our ability to access those funds, even for a short period of time, could have a material adverse effect on our results of operations and financial condition.

We Must Rely on Cash from Our Subsidiaries and Any Restrictions on Our Utility Subsidiaries' Ability to Pay Dividends or Make Cash Payments to Us May Adversely Affect Our Financial Condition

We are a holding company and our investments in our subsidiaries are our primary assets. Substantially all of our business is conducted by our subsidiaries. Consequently, our cash flow is dependent on the operating cash flows of our subsidiaries and their ability to upstream cash to the holding company. Our utility subsidiaries are regulated by various state utility commissions that generally possess broad powers to ensure that the needs of utility customers are being met. Those state commissions could attempt to impose restrictions on the ability of our utility subsidiaries to pay dividends or otherwise restrict cash payments to us.

We Cannot Assure Common Shareholders that Future Dividend Payments Will be Made, or if Made, in What Amounts they May be Paid

Our Board of Directors regularly evaluates our common stock dividend policy and determines the dividend rate each quarter. The level of dividends will continue to be influenced by many factors, including, among other things, our earnings, financial condition and cash flows from subsidiaries, as well as general economic and competitive conditions. We cannot assure common shareholders that dividends will be paid in the future, or that, if paid, dividends will be at the same amount or with the same frequency as in the past.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

The Ohio Companies', Penn's, FGCO’s and NGC’s respective first mortgage indentures constitute direct first liens on substantially all of the respective physical property, subject only to excepted encumbrances, as defined in the first mortgage indentures. See Notes 6, Leases, and 12, Capitalization of the Combined Notes to the Consolidated Financial Statements for information concerning leases and financing encumbrances affecting certain of the Utilities’, FGCO’s and NGC’s properties.

FirstEnergy controls the following generation sources as of January 31, 2012, shown in the table below. Except for the leasehold interests, OVEC participation and wind power arrangements referenced in the footnotes to the table, substantially all FES' competitive generating units are owned by NGC (nuclear) and FGCO (non-nuclear); the regulated generating units are owned by JCP&L and MP.

Plant (Location)	Unit	Total	Competitive FES	AE Supply	Regulated
		Net Demonstrated Capacity (MW)			
Super-critical Coal-fired:					
Bruce Mansfield (Shippingport, PA)	1	830 (1)	830	—	—
Bruce Mansfield (Shippingport, PA)	2	830 (2)	830	—	—
Bruce Mansfield (Shippingport, PA)	3	830 (3)	830	—	—
Harrison (Haywood, WV)	1-3	1,984	—	1,576	408
Hatfield's Ferry (Masontown, PA)	1-3	1,710	—	1,710	—
Pleasants (Willow Island, WV)	1-2	1,300	—	1,200	100
W. H. Sammis (Stratton, OH)	6-7	1,200	1,200	—	—
Fort Martin (Maidsville, WV)	1-2	1,107	—	—	1,107
Eastlake (Eastlake, OH)(4)	5	597	597	—	—
		10,388	4,287	4,486	1,615
Sub-critical and Other Coal-fired:					
W. H. Sammis (Stratton, OH)	1-5	1,020	1,020	—	—
Eastlake (Eastlake, OH)(4)	1-4	636	636	—	—
Bay Shore (Toledo, OH)	1	136	136		
Bay Shore (Toledo, OH)(4)	2-4	495	495	—	—
Armstrong (Adrian, PA)(4)	1-2	356	—	356	—
Albright (Albright, WV)(4)	1-3	292	—	—	292
Mitchell (Courtney, PA)	3	288	—	288	—
Lakeshore (Cleveland, OH)(4)	18	245	245	—	—
Ashtabula (Ashtabula, OH)(4)	5	244	244	—	—
Willow Island (Willow Island, WV)(4)	1-2	242	—	—	242
Rivesville (Rivesville, WV)(4)	5-6	126	—	—	126
R. Paul Smith (Williamsport, MD)(4)	3-4	116	—	116	—
R. E. Burger (Shadyside, OH)	3	94	94	—	—
OVEC (Cheshire, OH) (Madison, IN)	1-11	188 (5)	110	67	11
		4,478	2,980	827	671
Nuclear:					
Beaver Valley (Shippingport, PA)	1	911	911	—	—
Beaver Valley (Shippingport, PA)	2	904 (6)	904	—	—
Davis-Besse (Oak Harbor, OH)	1	908	908	—	—
Perry (N. Perry Village, OH)	1	1,268 (7)	1,268	—	—
		3,991	3,991	—	—
Gas/Oil-fired:					
AE Nos. 1, 2, 3, 4 & 5 (Springdale, PA)	1-5	638	—	638	—
West Lorain (Lorain, OH)	1-6	545	—	545	—
AE Nos. 12 & 13 (Chambersburg, PA)	12-13	88	—	88	—
AE Nos. 8 & 9 (Gans, PA)	8-9	88	—	88	—

Mitchell (Courtney, PA)	2	82	—	82	—
Hunlock CT (Hunlock Creek, PA)	1	45	—	45	—
Buchanan (Oakwood, VA)	1-2	43 (8)	—	43	—
Other		216	216	—	—
		1,745	216	1,529	—
Pumped-storage and Hydro:					
Bath County (Warm Springs, VA)	1-6	1,110 (9)	—	660	450
Seneca (Warren, PA)	1-3	451	451	—	—
Yard's Creek (Blairstown Twp., NJ)	1-3	200 (10)	—	—	200
Lake Lynn (Lake Lynn, PA)	1-4	52 (11)	—	52	
Other		19	—	19	—
		1,832	451	731	650
Wind Power		376 (12)	376	—	—
Total		22,810	12,301	7,573	2,936

(1) Includes FGCO's leasehold interest of 93.825% (779 MW) and CEI's leasehold interest of 6.175% (51 MW), which has been assigned to FGCO.
(2) Includes CEI's and TE's leasehold interests of 27.17% (226 MW) and 16.435% (136 MW), respectively, which have been assigned to FGCO.
(3) Includes CEI's and TE's leasehold interests of 23.247% (193 MW) and 18.915% (157 MW), respectively, which have been assigned to FGCO.
(4) During the first quarter of 2012, FirstEnergy announced that these coal-fired plants will be retired by September 1, 2012, subject to review for reliability impacts by PJM.
(5) Represents FGCO's 4.85% and AE's 3.5% entitlement based on their participation in OVEC.
(6) Includes OE's leasehold interest of 16.65% (151 MW) from non-affiliates.
(7) Includes OE's leasehold interest of 8.11% (103 MW) from non-affiliates.
(8) Buchanan Energy is a subsidiary of AE Supply. CNX Gas Corporation and Buchanan Energy have equal ownership interests in Buchanan Generation, LLC. AE Supply operates and dispatches 100% of Buchanan Generation, LLC's 86 MWs.
(9) Represents capacity entitlement through ownership of AGC.
(10) Represents JCP&L's 50% ownership interest.
(11) AE Supply has a license for Lake Lynn through 2024.
(12) Includes 167 MW from leased facilities and 209 MW under power purchase agreements.

The above generating plants and load centers are connected by a transmission system consisting of elements having various voltage ratings ranging from 23 kV to 500 kV. The Utilities' overhead and underground transmission lines aggregate 24,305 pole miles.

The Utilities' electric distribution systems include 254,899 miles of overhead pole line and underground conduit carrying primary, secondary and street lighting circuits. They own substations with a total installed transformer capacity of approximately 140,158,000 kV-amperes.

All of FirstEnergy's generation, transmission and distribution assets operate in PJM.

FirstEnergy's distribution and transmission systems as of December 31, 2011, consist of the following:

	Distribution Lines(1)	Transmission Lines(1)	Substation Transformer Capacity(2) kV Amperes
OE	62,238	461	7,763,000
Penn	13,419	52	1,425,000
CEI	33,252	—	8,938,000
TE	17,593	81	3,040,000
JCP&L	22,800	2,550	23,150,000
Met-Ed	18,695	1,406	10,819,000
Penelec	27,131	2,909	15,234,000
ATSI(3)	—	7,524	23,578,000
WP	20,026	4,419	14,077,000
MP	20,730	2,625	15,230,000
PE	19,015	2,126	11,033,000
TrAIL(4)	—	152	5,871,000
Total	254,899	24,305	140,158,000

(1) Pole miles
(2) Top rating of in-service power transformers only. Excludes grounding banks, station power transformers, and generator and customer-owned transformers.
(3) Represents transmission lines of 69kV and above located in the service areas of OE, Penn, CEI and TE.
(4) Represents transmission lines at 500kV located in the service areas of MP, PE and WP.

ITEM 3. LEGAL PROCEEDINGS

Reference is made to Note 16, Commitments, Guarantees and Contingencies of the Combined Notes to the Consolidated Financial Statements for a description of certain legal proceedings involving FirstEnergy, FES, OE, CEI, TE, JCP&L, Met-Ed and Penelec.

ITEM 4. MINE SAFETY DISCLOSURE

Signal Peak Mine Safety

During 2011, FirstEnergy, through its FEV wholly owned subsidiary, held a 50% interest in Global Mining Group, LLC, a joint venture owning 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 MSHA under the Mine Act.

On October 18, 2011, FirstEnergy announced that Gunvor Group, Ltd. signed an agreement to purchase a one-third interest in the Signal Peak coal mine in Montana. As a result of the sale, FirstEnergy, through its wholly owned subsidiary, FEV, currently has a 33-1/3% interest in Global Holding, a joint venture that owns Signal Peak.
Information concerning mine safety violations or other regulatory matters required by section 1503(a) of the Dodd-Frank Wall Street Reform and Consumer Protection Act is included in Exhibit 95 to this Annual Report on Form 10-K.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

The information required by Item 5 regarding FirstEnergy's market information, including stock exchange listings and quarterly stock market prices, dividends and holders of common stock is included in Item 6.
Information for FES, OE, CEI, TE, JCP&L, Met-Ed and Penelec is not disclosed because they are wholly owned subsidiaries of FirstEnergy and there is no market for their common stock.
Information regarding compensation plans for which shares of FirstEnergy common stock may be issued is incorporated herein by reference to FirstEnergy's 2012 proxy statement to be filed with the SEC pursuant to Regulation 14A under the Securities Exchange Act of 1934.
The table below includes information on a monthly basis regarding purchases made by FE of its common stock during the fourth quarter of 2011.

	Period			
	October	November	December	Fourth Quarter
Total Number of Shares Purchased[1]	112,225	167,674	712,539	992,438
Average Price Paid per Share	$44.36	$44.32	$44.19	$44.23
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	—	—	—	—

(1) 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 6. SELECTED FINANCIAL DATA

For the Years Ended December 31,	2011	2010[1]	2009[1]	2008[1]	2007[1]
	(In millions, except per share amounts)				
Revenues	$16,258	$13,339	$12,973	$13,627	$12,802
Earnings Available to FirstEnergy Corp.[2]	$885	$742	$872	$623	$1,489
Earnings per Share of Common Stock:[2]					
Basic	$2.22	$2.44	$2.87	$2.05	$4.86
Diluted	$2.21	$2.42	$2.85	$2.03	$4.80
Weighted Average Shares Outstanding:					
Basic	399	304	304	304	306
Diluted	401	305	306	307	310
Dividends Declared per Share of Common Stock[3]	$2.20	$2.20	$2.20	$2.20	$2.05
Total Assets[4]	$47,326	$35,531	$35,054	$34,206	$32,394
Capitalization as of December 31:					
Total Equity[5]	$13,299	$8,952	$9,014	$8,748	$9,129
Long-Term Debt and Other Long-Term Obligations	15,716	12,579	12,008	9,100	8,869

Total Capitalization[5]	$29,015	$21,531	$21,022	$17,848	$17,998

(1) Reflects the retrospective change in recognizing pensions and OPEB costs.

(2) The retrospective change in accounting for pensions and OPEB costs decreased Earnings Available to FirstEnergy Corp and Earnings Per Share (basic; diluted) as follows: 2010 - $42 million ($0.14; $0.15 per share), 2009 - $134 million ($0.44; $0.44 per share) and 2008 - $719

million ($2.36; $2.35 per share); and increased Earnings Available to FirstEnergy Corp. and Earnings Per Share (basic; diluted) in 2007 by $180 million ($0.59; $0.58 per share).

(3) Dividends declared in 2011, 2010, 2009 and 2008 include four quarterly dividends of $0.55 per share. Dividends declared in 2007 include three quarterly payments of $0.50 per share in 2007 and one quarterly payment of $0.55 per share in 2008.

(4) The retrospective change in accounting for pensions and OPEB costs increased Total Assets as of December 31 as follows: 2010 - $726 million, 2009 - $750 million, 2008 - $685 million and 2007 - $83 million.

(5) The retrospective change in accounting for pensions and OPEB costs increased Total Equity as of December 31 as follows: 2010 - $439 million, 2009 - $457 million, 2008 - $433 million and 2007 - $122 million.

PRICE RANGE OF COMMON STOCK

The common stock of FirstEnergy Corp. is listed on the New York Stock Exchange under the symbol “FE” and is traded on other registered exchanges.

	2011		2010	
	High	Low	High	Low
First Quarter	$40.80	$36.11	$47.09	$38.31
Second Quarter	$45.80	$36.50	$39.96	$33.57
Third Quarter	$46.51	$38.77	$39.06	$34.51
Fourth Quarter	$46.10	$41.55	$40.12	$35.00
Yearly	$46.51	$36.11	$47.09	$33.57

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

SHAREHOLDER RETURN

The following graph shows the total cumulative return from a $100 investment on December 31, 2006 in FirstEnergy’s common stock compared with the total cumulative returns of EEI’s Index of Investor-Owned Electric Utility Companies and the S&P 500.

HOLDERS OF COMMON STOCK

There were 115,120 and 114,808 holders of 418,216,437 shares of FirstEnergy’s common stock as of December 31, 2011 and January 31, 2012, respectively. Information regarding retained earnings available for payment of cash dividends is given in Note 12, Capitalization of the Combined Notes to the Consolidated Financial Statements.

CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF REGISTRANT AND SUBSIDIARIES

Forward-Looking Statements: This Form 10-K 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-looking 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 before FERC 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.
- 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 CSAPR which was stayed by the courts on December 30, 2011, and the effects of the EPA's MATS rules.
- The uncertainty of the timing and amounts of the capital expenditures that may arise in connection with litigation, including 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).
- The uncertainty associated with the company's plan to retire its older unscrubbed regulated and competitive fossil units, including the impact on vendor commitments and PJM's review of the company's plans.
- 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).
- Issues that could result from our continuing investigation and analysis of the indications of cracking in the plant shield building at Davis-Besse.
- 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.
- FirstEnergy's 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 NDTs, pension trusts and other trust funds, and cause FirstEnergy and its subsidiaries to make additional contributions sooner, or in amounts that are larger than currently anticipated.
- The impact of changes to material accounting policies.
- 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 of financings 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 major industrial and commercial customers of FirstEnergy and its subsidiaries.
- Issues concerning the soundness of financial institutions and counterparties with which FirstEnergy and its subsidiaries do business.
- Issues arising from the completed merger of FirstEnergy and AE 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 continue to successfully integrate the businesses and realize cost savings and any other synergies .

- The risks and other factors discussed from time to time in FirstEnergy's and its applicable subsidiaries' SEC filings, and other similar factors.

Dividends declared from time to time on FE's common stock during any annual period may in the aggregate vary from the indicated amount due to circumstances considered by FE'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 FirstEnergy's 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, except as required by law, any forward-looking statements contained herein as a result of new information, future events or otherwise.

See Item 1A. Risk Factors for additional information regarding risks that may impact our business, financial condition and results of operations.

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

Earnings available to FirstEnergy Corp. in 2011 were $885 million, or $2.22 per basic share of common stock ($2.21 diluted), compared with $742 million, or $2.44 per basic share of common stock ($2.42 diluted), in 2010 and $872 million, or $2.87 per basic share ($2.85 diluted), in 2009.

Change in Earnings Per Basic Share From Prior Year	2011	2010
Earnings Per Basic Share — Prior Year	$2.44	$2.87
Segment operating results[1]-		
Regulated Distribution	0.05	0.04
Competitive Energy Services	(0.15)	0.10
Regulated Independent Transmission	(0.06)	0.12
Non-core asset sales/impairments	0.67	(0.37)
Generating plant impairments	0.08	(0.78)
Trust securities impairments	0.02	0.03
Litigation resolution	(0.07)	0.01
Regulatory charges	0.03	0.45
Mark-to-market adjustments-		
Pension and OPEB actuarial assumptions	(0.47)	0.30
All other	0.02	0.35
Organizational restructuring - 2009	—	0.14
Debt redemption premiums	(0.01)	0.32
Merger-related costs	(0.29)	(0.16)
Merger Accounting - commodity contracts	(0.26)	—
Net merger accretion[1][2][3]	0.54	—
Income tax resolution / retiree drug subsidy	(0.03)	(0.57)
Settlement of uncertain tax positions	(0.05)	(0.11)
Depreciation	(0.09)	(0.02)
Interest expense, net of amounts capitalized	(0.14)	0.04
Investment income	(0.03)	(0.19)
Change in effective tax rate	0.04	(0.17)
Other	(0.02)	0.04
Earnings Per Basic Share	$2.22	$2.44

(1)Excludes amounts that are shown separately
(2)Includes dilutive effect of shares issued in connection with the Allegheny merger
(3)Includes 10 months of Allegheny results in 2011

Merger

On February 25, 2011, the merger between FirstEnergy and AE closed. Pursuant to the terms of the Agreement and Plan of Merger between 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 merger transaction costs of approximately $91 million ($73 million net of tax and $65 million ($47 million net of tax) during 2011 and 2010, respectively. These costs are included in "Other operating expenses" in the Consolidated Statements of Income. In addition, during 2011, $93 million of pre-tax merger integration costs and $36 million of pre-tax 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 exceeded its 2011 merger benefits target. During 2011, FirstEnergy completed savings initiatives that allowed the company to capture pre-tax annualized merger benefits of approximately $267 million compared to the annual target of $210 million.

Operational Matters

PJM RTO Integration

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.

Transmission Expansion

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.

Nuclear Generation

On April 11, 2011, Beaver Valley Power Station Unit 2 returned to service following a March 7, 2011 shutdown for refueling and maintenance. During the outage, 60 of the 157 fuel assemblies were exchanged, safety inspections were conducted, and numerous maintenance and improvement projects were completed that we believe will result in continued safe and reliable operations.

On June 7, 2011, the Perry Nuclear Power 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.

On October 2, 2011, FENOC completed the controlled shutdown of the Perry Plant due to the loss of a startup transformer. Subsequently, a spare replacement transformer from Davis-Besse Nuclear Power Station was transported to the Perry Plant for modification and installation. The new transformer was installed in 2011.

During 2011, FENOC broke ground for new Emergency Operations Facilities at all three of its nuclear sites. 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.

On October 1, 2011, the Davis-Besse Nuclear Power Station began a scheduled outage for replacement of its reactor vessel head and other scheduled maintenance. On October 10, 2011, following opening of the building for installation of the new reactor head, a sub-surface hairline crack was identified in one of the exterior architectural elements on the shield building. These elements serve as architectural features and do not have structural significance. During investigation of the crack at the shield building opening, concrete samples and electronic testing found similar sub-surface hairline cracks in most of the building's architectural elements. FENOC's investigation also identified other indications of cracking. Included among them were sub-surface hairline cracks in the upper portion of the shield building (above 780 feet of elevation) and in the vicinity of the main steam line penetrations. A team of industry-recognized structural concrete experts and Davis-Besse engineers have determined these conditions do not affect the facility's structural integrity or safety. On February 27, 2012, FENOC sent a root cause evaluation report to the NRC. On December 6, 2011, the Davis-Besse Nuclear Power Station returned to service. The new reactor vessel head features control rod nozzles made of an enhanced material and further promotes safe and reliable operation of the plant.

Coal and Gas Fired Generation

On July 28, 2011, FirstEnergy completed the sale of the 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.

On October 18, 2011, FirstEnergy sold its Richland (432 MW) and Stryker (18 MW) Peaking Facilities for approximately $80 million. The proceeds from the sale of these non-core assets reduced FirstEnergy's net debt position.

On January 26, 2012, FirstEnergy announced that its unregulated generation subsidiaries will retire six older coal-fired plants located in Ohio, Pennsylvania and Maryland. On February 8, 2012, FirstEnergy announced that MP will retire three older coal-fired plants located in West Virginia. All of these generating plants will be closed by September 1, 2012. The decision to close the plants is the result of a comprehensive review of FirstEnergy's coal-fired generating facilities in light of the MATS rules that were recently finalized and other environmental regulations. These closures are subject to review for reliability impacts by PJM. In addition, MP will make a filing with the WVPSC to provide them with information regarding the retirement of its plants. As a result of this decision, impairment charges associated with these assets were recognized by FirstEnergy, aggregating approximately $334 million ($207 million after-tax) in the fourth quarter of 2011, including approximately $243 million ($152 million after-tax) which is applicable to FES. See Note 11, Impairment of Long-lived Assets, for further information on the retirement of these plants.

The total capacity of the competitive plants that will be retired is approximately 2,700 MW and the total capacity of the three regulated plants that will be retired is approximately 660 MW. Recently, these plants served mostly as peaking or intermediate facilities, generating, on average, approximately 10 percent of the electricity produced by FirstEnergy's generation subsidiaries over the past three years.

On February 24, 2012, PJM notified FirstEnergy of its preliminary analysis of the reliability impacts that may result from closure of the older competitive coal-fired generating units. PJM's preliminary analysis indicated that there would be significant reliability concerns that will need to be addressed. FirstEnergy intends to continue to actively engage in discussions with PJM regarding this notification, including the possible continued operation of certain plants.

Signal Peak

On October 18, 2011, FirstEnergy announced that Gunvor Group, Ltd. purchased a one-third interest in Global Holding, a joint venture that owns the Signal Peak coal mine in Montana and the related Global Rail coal transportation operations. The sale strengthened FirstEnergy's balance sheet in the following ways:

- Proceeds of $257.5 million reduced FirstEnergy's net debt position;
- De-consolidation of Signal Peak resulted in the reduction of indebtedness by $360 million and an increase to equity of $50 million on FirstEnergy's Consolidated Balance Sheet; and
- The gain on sale and revaluation of FirstEnergy's remaining ownership stake increased equity by an additional $370 million.

Following the sale, FirstEnergy, through its wholly owned subsidiary, FEV, has a one-third interest in Global Holding. FGCO has a long-term coal supply agreement with Signal Peak for up to 10 million tons per year. FGCO has re-evaluated its coal usage under that agreement and has determined to resell its coal purchased from Signal Peak to an affiliate of Global Holding; provided, however, that such affiliate may require FGCO to repurchase up to 2 million tons annually from the existing underground mines, and, if Signal Peak develops surface mines, it could require FGCO to purchase an additional 2 million tons per year. FirstEnergy remains a 100% guarantor on Signal Peak's and Global Rail's $350 million senior secured credit facility. See Guarantees and Other Assurances below.

FirstEnergy Utilities Respond to Unprecedented Storms

In late August 2011, FirstEnergy experienced unprecedented damage in its service territory as a result of Hurricane Irene. Approximately 1.1 million customers were affected by outages in areas served by JCP&L, Met-Ed, Penelec and PE. Approximately 5,000 FirstEnergy employees and 2,800 contractors, including utility line workers from other utilities, assisted with the restoration work. The cost of the storm totaled approximately $89 million, of which $4 million reduced pre-tax income in 2011 and $85 million was capitalized or deferred for future recovery from customers.

On October 29, 2011, FirstEnergy was affected by a snowstorm that paralyzed much of the East Coast, including our eastern service areas. Approximately 820,000 customers of JCP&L, Met-Ed, PE, MP, Penelec and WP were affected by the storm that brought down more than 800 poles and approximately 10,000 spans of wire. More than 9,600 employees, contractors and other utilities' crews helped in the restoration. The pre-tax total cost of the storm was approximately $125 million, of which $6 million reduced pre-tax income in 2011 and $119 million was capitalized or deferred for future recovery from customers.

Financial Matters

During 2011, FirstEnergy redeemed or repurchased approximately $520.4 million principal amount of PCRBs, as summarized in the following table. Approximately $28.5 million of FGCO FMBs and $98.9 million of NGC FMBs associated with the PCRBs were returned for cancellation by the associated LOC providers.

Subsidiaries	Amount (In millions)	
AE Supply	$53.0	(1)
FGCO	$198.2	(2)
NGC	$213.5	(2)
MP	$70.2	(1)

(1) Includes $14.4 million of PCRBs redeemed for which MP and AE Supply are co-obligors.

(2) Subject to market conditions, these PCRBs are being held for future remarketing.

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 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 utility subsidiaries 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.

During the third quarter of 2011, FirstEnergy received approximately $130 million from assigning a substantially below-market, long-term fossil fuel contract to a third party. As a result, FirstEnergy entered into a new long-term contract with another supplier for replacement fuel based on current market prices. The new contract runs for nine years, which is the remaining term of the assigned contract. The transaction reduced fuel costs during the quarter by approximately $123 million.

TrAIL's primary investment, the Trans-Allegheny Interstate Line (a 500-kV transmission project that extends from Southwestern Pennsylvania through West Virginia to Northern Virginia), was completed in May 2011.

On January 26, 2012, FirstEnergy announced a change to its method for accounting for pensions and OPEB effective in 2011 (see Note 1, Organization, Basis of Presentation and Significant Accounting Policies of the Combined Notes to the Consolidated Financial Statements). We also disclosed that we made a $600 million voluntary contribution to our pension plan earlier that month.

Regulatory Matters

Met-Ed and Penelec Transition to Competitive Markets

The Pennsylvania Companies began the move to competitive markets with the expiration of the rate caps on Met-Ed's and Penelec's retail generation rates on December 31, 2010. Beginning in 2011, Met-Ed and Penelec obtained their power supply from the competitive wholesale market and fully recover their generation costs through retail rates. The Ohio Companies, Penn, WP and JCP&L previously transitioned to competitive generation markets.

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 the outcome of court appeals.

Ohio Energy Efficiency and Peak Demand Reduction Portfolio Plan

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

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.

West Virginia Fuel, Purchased Power Cost Decision

On December 30, 2011, MP and PE announced that the WVPSC issued an order regarding the companies' adjustment of fuel and purchased power costs. The WVPSC's order approved a settlement agreement between the companies, the Consumer Advocate Division, the Staff of the WVPSC and the West Virginia Energy Users Group. In the approved settlement, parties have agreed that the companies will recover an additional $19.6 million in 2012, an approximate 1.7 percent increase, primarily reflecting rising coal prices over the past two years, with certain additional amounts to be recovered over time with a carrying charge.

FIRSTENERGY’S BUSINESS

With the completion of the AE 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” amounts 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 revised 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 AE, and certain regulatory asset recovery mechanisms formerly included in the “Other/Corporate” segment, were placed into this segment.
- A new Regulated Independent Transmission segment was created consisting of ATSI, and the operations of TrAIL and FirstEnergy's interest in PATH; TrAIL and PATH were acquired as part of the merger with AE. The transmission assets and operations of JCP&L, Met-Ed, Penelec, MP, PE and WP remained within the Regulated Distribution segment.
- AE Supply, an operator of generation facilities that was acquired as part of the merger with AE, was placed into the Competitive Energy Services segment with FES.

Regulated Distribution distributes electricity through our ten utility distribution 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. Its results reflect the commodity costs of securing electric generation and the deferral and amortization of certain fuel costs.

The service areas of our regulated distribution utilities are summarized below:

Company	Area Served	Customers Served
OE	Central and Northeastern Ohio	1,032,000
Penn	Western Pennsylvania	161,000
CEI	Northeastern Ohio	747,000
TE	Northwestern Ohio	309,000
JCP&L	Northern, Western and East Central New Jersey	1,099,000
Met-Ed	Eastern Pennsylvania	553,000
Penelec	Western Pennsylvania	590,000
WP	Southwest, South Central and Northern Pennsylvania	718,000
MP	Northern, Central and Southeastern West Virginia	387,000
PE	Western Maryland and Eastern West Virginia	390,000
		5,986,000

Regulated Independent Transmission transmits electricity through transmission lines and its revenues are primarily derived from a formulaic rate that recovers costs and a return on investment for capital expenditures in connection with TrAIL, PATH and other projects, revenues from providing transmission services to electric energy providers and power marketers, and revenues from operating a portion of the FirstEnergy transmission system. Its results reflect the net transmission expenses related to the delivery of the respective generation loads.

Competitive Energy Services supplies, through FES and AE Supply, electric power to end-use customers through retail and wholesale arrangements, including competitive retail sales to customers primarily in Ohio, Pennsylvania, Illinois, Michigan, New Jersey and Maryland and the provision of partial POLR and default service for some utilities in Ohio, Pennsylvania and Maryland, including but not limited to the Utilities. This segment controls approximately 17,000 MWs of capacity (excluding approximately 2,700 MWs from unregulated plants expected to be closed by September 1, 2012) (see Note 11, Impairment of Long-Lived Assets of the Combined Notes to the Consolidated Financial Statements) and also purchases electricity to meet sales obligations. The segment's net income is primarily derived from 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.
Other/Corporate contains corporate items and other businesses that are below the quantifiable threshold for separate disclosure as a reportable segment. (See Note 19, Segment Information of the Combined Notes to the Consolidated Financial Statements for further information on FirstEnergy's reportable operating segments.)

STRATEGY AND OUTLOOK

FirstEnergy's vision is to be a leading regional energy provider, recognized for operational excellence, outstanding customer service and our commitment to safety; the choice for long-term growth, investment value and financial strength; and a company driven by the leadership, skills, diversity and character of our employees.

FirstEnergy has grown over the last 15 years through several strategic mergers and asset transactions. Our most recent merger with Allegheny was completed in February 2011, significantly increasing our customer base and generating capacity and accelerating our movement further into eastern competitive markets. Also during 2011, we completed the transition to competitive markets in Pennsylvania and moved our ATSI assets into PJM, so that we now operate within a single regional transmission system.

FirstEnergy is uniquely positioned as the nation's largest contiguous electric system, with complementary assets across our generation, transmission and distribution delivery operations. These assets are in a prime location of PJM's competitive markets.

Our substantial regulated operations include 10 distribution utilities serving a balanced base of nearly 6 million customers across 5 states. We are also one of the largest owners of transmission assets in PJM with nearly 20,000 miles of high-voltage lines, including two independent transmission companies with significant assets. Combined, our utilities and transmission operations provide financial stability with strong cash flow and dividend support to FirstEnergy.

Our market-focused business model integrates more than 17,000 MWs of competitive generation, excluding approximately 2,700 MWs from unregulated plants expected to be closed by September 1, 2012, and are subject to review by PJM for reliability impacts(see Note 16, Commitment, Guarantees and Contingencies, regarding PJM's review of the our plans), with a multi-channel retail sales platform, providing a higher value for every MWH we generate. We primarily target customers in competitive markets close to our generation assets.

We believe we are well-positioned for upcoming environmental changes due to the considerable investments we have made in recent years to diversify our generation fleet and improve its environmental performance. As a result of the MATS rules recently finalized by the EPA, and other previously announced environmental regulations, FirstEnergy announced in early 2012 its intent to retire nine older coal-fired power plants, totaling 3,349 MW, located in Ohio, Pennsylvania, Maryland and West Virginia by September 1, 2012. When the retired fossil plants are removed from our fleet, nearly 100% percent of our generation output will be from either low or non-emitting facilities, including nuclear, hydro, natural gas and scrubbed coal units. This further positions our fleet to deliver superior value in the future.

We continue to face challenges related to macro-economic factors. These include slow economic recovery across portions of our service territory, which affect our distribution deliveries volumes to residential, commercial and industrial customers, and depressed natural gas and wholesale electricity prices, which affect revenues from our competitive retail business and generation fleet. However, we believe we are one of the better positioned companies in our industry to benefit from eventual increases in energy and capacity prices as economic conditions improve.

Financial Outlook

We intend to manage our operating and capital costs in order to achieve our financial goals and commitment to shareholders.

Our liquidity position remains strong, with approximately $49 million of short-term cash investments and over $4.3 billion of available liquidity as of January 31, 2012.

Positive earnings drivers for 2012 are expected to include:

A full year contribution from the Allegheny merger;

Higher competitive retail revenues as a result of continued growth in the business;

Lower fuel and operation and maintenance expenses due to the retirement of certain coal-fired plants in 2012 and from a continued focus on controlling our costs; and

Reduced interest expense as a result of debt redemptions during 2011.

Negative earnings drivers for 2012 are expected to include:

Lower margins for our competitive energy service business from depressed market prices of power and lower capacity prices resulting from the PJM RPM auction beginning June 1, 2012;

Higher gross receipts taxes associated with increased competitive retail sales in Pennsylvania; and

Increased depreciation expenses from capital projects that were placed in service during 2011.

On January 5, 2012, we made a $600 million voluntary contribution to our pension plan bringing its funding level to 90% on an accumulated benefit obligation basis.

Capital Expenditures Outlook

Our capital expenditures in 2012 are estimated to be $2.1 billion (excluding nuclear fuel), a decrease of approximately $393 million from 2011. In addition to internal sources to fund capital requirements for 2012 and beyond, FirstEnergy expects to rely on external sources of funds.

Capital expenditures for our Regulated Distribution segment are forecast to decrease by $63 million in 2012 from $1.1 billion in 2011. The expected decrease primarily reflects the absence of storm restoration costs related to Hurricane Irene and the October 2011 snowstorm. For our Regulated Independent Transmission segment, capital expenditures are expected to decrease to $105 million in 2012 from $190 million in 2011. The decrease reflects the completion of TrAIL's 500-kV transmission line in 2011.

Expenditures for Ohio and Pennsylvania energy efficiency and advanced metering initiatives are expected to be primarily recovered from distribution customers and federal stimulus funding. Other capital investments in our transmission and distribution infrastructure are planned to satisfy transmission capacity and reliability requirements, connect new load delivery and wholesale generation points, and achieve cost-effective improvements in the reliability of our service.

For our Competitive Energy Services segment, capital expenditures are expected to increase by $32 million to $803 million in 2012. The main drivers of the increase include steam generator replacement projects at Davis-Besse and Beaver Valley Unit 2 and turbine rotor replacement projects at Perry and Beaver Valley Unit 2. Other planned generation investments provide for maintenance of critical generation assets, delivering operational improvements to enhance reliability, supporting environmental compliance, and advancing our generation to market strategy.

For 2013, we anticipate baseline capital expenditures of approximately $2.0 billion, which exclude any potential additional strategic opportunities, future mandated spending, energy efficiency or environmental spending relating to MATS. Planned capital initiatives are intended to promote reliability, improve operations, and support current environmental and energy efficiency directives.

Environmental Outlook

We continually strive to enhance environmental protection and remain good stewards of our natural resources. We devote significant resources to environmental compliance efforts, and our employees share a commitment to, and accountability for, environmental performance. Our corporate focus on continuous improvement is integral to our environmental programs.

We have spent more than $10 billion on environmental protection efforts since the initial passage of the Clean Air and Water Acts in the 1970s, and these investments demonstrate our continuing commitment to the environment. Recent investments of $3.0 billion at our Hatfield, Fort Martin and Sammis Plants, further reduced emissions of SO_2 by over 95%, and NOx by at least 64% at these facilities. Since 1990, we have reduced emissions of NOx by more than 76%,

SO_2 by more than 86%, and mercury by approximately 56%.

We have taken aggressive steps over the past two decades that have increased our generating capacity without adding to overall CO_2 emissions. For example, since 1990, we have reconfigured our fleet by retiring 1,312 MWs and committing to retire in the near future 3,349 MWs of older, coal-based generation and adding more than 1,800 MWs of non-emitting capacity. Through these and other actions, we have increased our generating capacity by nearly 15% over the same period while avoiding over 370 million metric tons of CO_2 emissions.

We have taken a leadership role in pursuing new ventures to test and develop new technologies that may achieve additional reductions in CO_2 emissions. These include:

Sales of over 1 million MWH per year of wind generation.

CO_2 sequestration testing to gain a better understanding of the potential for geological storage of CO_2.

Supporting afforestation - growing forests on non-forested land - and other efforts designed to remove CO_2 from the environment.

Reducing emissions of SF_6 (sulfur hexafluoride) by nearly 15 metric tons, resulting in an equivalent reduction of nearly 315,000 metric tons of CO_2, through the EPA's SF_6 Emissions Reduction Partnership for Electric Power Systems.

Supporting research to develop and evaluate cost effective sorbent materials for CO_2 capture including work by EPRI and The University of Akron.

We remain actively engaged in the federal and state debate over future environmental requirements and legislation. We actively work with policy makers and regulators to develop fair and reasonable requirements, with the goal of reducing emissions while minimizing the economic impact on our customers. Due to the significant uncertainty as to the final form or timing of a significant number of regulations and legislation at both the federal and state levels, we are unable to determine the potential impact and risks associated with all future environmental requirements. The CSAPR was stayed at the end of 2011 and the federal appeals court reviewing CSAPR has scheduled an April 13, 2012 hearing. The new MATS were finalized at the end of 2011, which resulted in our decision to retire nine older coal-fired generation plants by September 1, 2012. Our current estimate is that it may cost approximately $1.3 - $1.7 billion to bring our remaining units into compliance.

We also have a long history of supporting research in distributed energy resources. Distributed energy resources include fuel cells, solar and wind systems or energy storage technologies located close to the customer or direct control of customer loads to provide alternatives or enhancements to the traditional electric power system. We are testing the world's largest utility-scale fuel cell system to determine its feasibility for augmenting generating capacity during summer peak-use periods. Through a partnership with EPRI, the Cuyahoga Valley National Park, the Department of Defense and Case Western Reserve University, two solid-oxide fuel cells were installed as part of a test program to explore the technology and the environmental benefits of distributed generation.

We are also evaluating the impact of distributed energy storage on the distribution system through analysis and field demonstrations of advanced battery technologies. FirstEnergy's EasyGreen® load-management program utilizes two-way communication capability with customers' non-critical equipment, such as air conditioners in New Jersey and Pennsylvania, to help manage peak loading on the electric distribution system. We have also made an online interactive energy efficiency tool, Home Energy Analyzer, available to our customers to help achieve electricity use reduction goals.

RISKS AND CHALLENGES

In executing our strategy, we face a number of industry and enterprise risks and challenges. See ITEM 1A. RISK FACTORS for a discussion of the risks and challenges faced by FirstEnergy and the Registrants.

RESULTS OF OPERATIONS

The financial results discussed below include revenues and expenses from transactions among FirstEnergy’s business segments. A reconciliation of segment financial results is provided in Note 19, Segment Information of the Combined Notes to the Consolidated Financial Statements. As described in Note 1, Organization, Basis of Presentation and Significant Accounting Policies, FirstEnergy elected to change its method of recognizing actuarial gains and losses for its defined benefit pension and OPEB plans and applied this change retrospectively to all periods presented. Earnings available to FirstEnergy by major business segment were as follows:

				Increase (Decrease)	
	2011	2010	2009	2011 vs 2010	2010 vs 2009
	(In millions, except per share data)				
Earnings By Business Segment:					
Regulated Distribution	$570	$553	$335	$17	$218
Competitive Energy Services	377	210	446	167	(236)
Regulated Independent Transmission	112	54	39	58	15
Other and reconciling adjustments[1]	(174)	(75)	52	(99)	(127)
Earnings available to FirstEnergy Corp.	$885	$742	$872	$143	$(130)
Earnings Per Basic Share	$2.22	$2.44	$2.87	$(0.22)	$(0.43)

Earnings Per Diluted Share	$2.21	$2.42	$2.85	$(0.21)	$(0.43)

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

Summary of Results of Operations — 2011 Compared with 2010

Financial results for FirstEnergy's major business segments in 2011 and 2010 were as follows:

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2011 Financial Results	Regulated Distribution	Competitive Energy Services	Regulated Independent Transmission	Other and Reconciling Adjustments	FirstEnergy Consolidated
	(In millions)				
Revenues:					
External					
Electric	$9,544	$5,573	$—	$—	$15,117
Other	460	363	391	(140)	1,074
Internal	—	1,237	—	(1,170)	67
Total Revenues	10,004	7,173	391	(1,310)	16,258
Operating Expenses:					
Fuel	268	2,049	—	—	2,317
Purchased power	4,672	1,491	—	(1,177)	4,986
Other operating expenses	1,662	2,256	68	(77)	3,909
Pensions and OPEB mark-to-market adjustment	290	215	2	—	507
Provision for depreciation	620	415	60	26	1,121
Amortization of regulatory assets, net	323	—	6	—	329
General taxes	724	200	33	21	978
Impairment of long-lived assets	87	315	—	11	413
Total Operating Expenses	8,646	6,941	169	(1,196)	14,560
Operating Income	1,358	232	222	(114)	1,698
Other Income (Expense):					
Gain on partial sale of Signal Peak	—	569	—	—	569
Investment income	110	56	—	(52)	114
Interest expense	(573)	(298)	(46)	(91)	(1,008)
Capitalized interest	10	40	2	18	70
Total Other Income (Expense)	(453)	367	(44)	(125)	(255)
Income Before Income Taxes	905	599	178	(239)	1,443
Income taxes	335	222	66	(49)	574
Net Income	570	377	112	(190)	869
Loss attributable to noncontrolling interest	—	—	—	(16)	(16)
Earnings available to FirstEnergy Corp.	$570	$377	$112	$(174)	$885

2010 Financial Results	Regulated Distribution	Competitive Energy Services	Regulated Independent Transmission	Other and Reconciling Adjustments	FirstEnergy Consolidated
	(In millions)				
Revenues:					
External					
Electric	$9,271	$3,252	$—	$—	$12,523
Other	300	323	242	(123)	742
Internal	139	2,301	—	(2,366)	74
Total Revenues	9,710	5,876	242	(2,489)	13,339
Operating Expenses:					
Fuel	—	1,432	—	—	1,432
Purchased power	5,273	1,724	—	(2,373)	4,624
Other operating expenses	1,320	1,393	61	(78)	2,696
Pensions and OPEB mark-to-market adjustment	82	107	(2)	3	190
Provision for depreciation	433	284	37	14	768
Amortization of regulatory assets, net	712	—	10	—	722
General taxes	605	124	30	17	776
Impairment of long-lived assets	—	388	—	—	388
Total Operating Expenses	8,425	5,452	136	(2,417)	11,596
Operating Income	1,285	424	106	(72)	1,743
Other Income (Expense):					
Investment income	102	51	—	(36)	117
Interest expense	(500)	(232)	(22)	(91)	(845)
Capitalized interest	4	95	2	64	165
Total Other Expense	(394)	(86)	(20)	(63)	(563)
Income Before Income Taxes	891	338	86	(135)	1,180
Income taxes	338	128	32	(36)	462
Net Income	553	210	54	(99)	718
Loss attributable to noncontrolling interest	—	—	—	(24)	(24)
Earnings available to FirstEnergy Corp.	$553	$210	$54	$(75)	$742

Changes Between 2011 and 2010 Financial Results Increase (Decrease)	Regulated Distribution	Competitive Energy Services	Regulated Independent Transmission	Other and Reconciling Adjustments	FirstEnergy Consolidated
	(In millions)				
Revenues:					
External					
Electric	$273	$2,321	$—	$—	$2,594
Other	160	40	149	(17)	332
Internal	(139)	(1,064)	—	1,196	(7)
Total Revenues	294	1,297	149	1,179	2,919
Operating Expenses:					
Fuel	268	617	—	—	885
Purchased power	(601)	(233)	—	1,196	362
Other operating expenses	342	863	7	1	1,213
Pensions and OPEB mark-to-market adjustment	208	108	4	(3)	317
Provision for depreciation	187	131	23	12	353
Amortization of regulatory assets, net	(389)	—	(4)	—	(393)
General taxes	119	76	3	4	202
Impairment of long-lived assets	87	(73)	—	11	25
Total Operating Expenses	221	1,489	33	1,221	2,964
Operating Income	73	(192)	116	(42)	(45)
Other Income (Expense):					
Gain on partial sale of Signal Peak	—	569	—	—	569
Investment income	8	5	—	(16)	(3)
Interest expense	(73)	(66)	(24)	—	(163)
Capitalized interest	6	(55)	—	(46)	(95)
Total Other Income (Expense)	(59)	453	(24)	(62)	308
Income Before Income Taxes	14	261	92	(104)	263
Income taxes	(3)	94	34	(13)	112
Net Income	17	167	58	(91)	151
Loss attributable to noncontrolling interest	—	—	—	8	8
Earnings available to FirstEnergy Corp.	$17	$167	$58	$(99)	$143

Regulated Distribution — 2011 Compared with 2010

Net income increased by $17 million in 2011 compared to 2010, primarily due to earnings from the Allegheny companies and the absence of a 2010 regulatory asset impairment associated with the Ohio companies' ESP, partially offset by higher pensions and OPEB mark-to-market adjustment charges and merger-related costs. Lower generation revenues were offset with lower purchased power expenses.

Revenues —

The increase in total revenues resulted from the following sources:

Revenues by Type of Service	For the year ended December 31 2011	2010	Increase (Decrease)	
	(In millions)			
Pre-merger companies:				
Distribution services	$3,426	$3,629	$(203	)
Generation:				
Retail	3,266	4,457	(1,191	)
Wholesale	377	702	(325	)
Total generation sales	3,643	5,159	(1,516	)
Transmission	262	596	(334	)
Other	187	326	(139	)
Total pre-merger companies	7,518	9,710	(2,192	)
Allegheny companies	2,486	—	2,486	
Total Revenues	$10,004	$9,710	$294	

The decrease in distribution service revenues for the pre-merger companies (FirstEnergy as it was organized prior to the February 2011 merger with Allegheny) primarily reflects lower transition revenues due to the completion of transition cost recovery by CEI in December 2010, an NJBPU-approved rate adjustment that became effective March 1, 2011, for all JCP&L customer classes, and the mid-year suspension of the Ohio Companies' recovery of deferred distribution costs. Partially offsetting the decreased distribution service revenues were increased rates in Met-Ed's and Penelec's transition riders and energy efficiency riders for the Pennsylvania and Ohio Companies. Distribution deliveries (excluding the Allegheny companies) increased by 0.1% in 2011 from 2010.The change in distribution deliveries by customer class is summarized in the following table:

Electric Distribution MWH Deliveries	For the year ended December 31 2011	2010	Increase (Decrease)	
Pre-merger companies:				
Residential	39,369	39,820	(1.1	)%
Commercial	32,610	33,096	(1.5	)%
Industrial	35,637	34,613	3.0	%
Other	513	522	(1.7	)%
Total pre-merger companies	108,129	108,051	0.1	%
Allegheny companies	33,449			
Total Electric Distribution MWH Deliveries	141,578	108,051	31.0	%

Lower deliveries to residential and commercial customers primarily reflected decreased weather-related usage resulting from lower heating degree days (4%) and cooling degree days (7%) in 2011 compared to 2010. In the industrial sector, MWH deliveries increased to steel and electrical equipment customers by 10% and 12%, respectively, partially offset by decreased deliveries to automotive customers of 2% in 2011 compared to 2010.

The following table summarizes the price and volume factors contributing to the $1,516 million decrease in generation revenues for the pre-merger companies in 2011 compared to 2010:

Source of Change in Generation Revenues	Increase (Decrease) (In millions)
Retail:	
Effect of decrease in sales volumes	$(1,638)
Change in prices	447
	(1,191)
Wholesale:	
Effect of decrease in sales volumes	(104)
Change in prices	(221)
	(325)
Net Decrease in Generation Revenues	$(1,516)

The decrease in retail generation sales volume was primarily due to increased customer shopping in the service territories of the pre-merger companies in 2011 compared to 2010. Total generation provided by alternative suppliers as a percentage of total MWH deliveries increased to 76% from 62% for the Ohio Companies, and to 52% from 10% in Met-Ed's, Penelec's and Penn's service territories. The increase in retail prices is the result of higher generation charges in Pennsylvania due to the removal of generation rate caps for Met-Ed and Penelec beginning on January 1, 2011, and the inclusion of transmission as part of the price of generation. Those impacts were partially offset by a decrease in the Ohio Companies' generation rates beginning in June 2011 with the removal of certain transmission charges in connection with the integration into PJM.

The decrease in wholesale generation revenues reflected lower RPM revenues for Met-Ed and Penelec in the PJM market.

Transmission revenues decreased $334 million primarily due to the termination of Met-Ed's and Penelec's TSC rates effective January 1, 2011. This is partially offset by a new rider that became effective for the Ohio Companies in June 2011 that recovers network integration transmission service charges.

Other revenues decreased by $139 million primarily due to the termination of Met-Ed's and Penelec's PSA with FES as of December 31, 2010, resulting in decreased capacity revenues.

The Allegheny companies added $2,486 million to revenues in 2011, including $571 million for distribution services, $1,661 million from generation sales, $212 million of transmission revenues and $42 million of other revenues.

Operating Expenses —

Total operating expenses increased by $221 million in 2011. Excluding the Allegheny companies, total operating expenses decreased $1.9 billion due to the following:

- Purchased power costs were $1.7 billion lower in 2011 due primarily to a decrease in volumes required. Decreased power purchased from FES primarily reflected the increase in customer shopping described above, the termination of Met-Ed's and Penelec's PSA with FES at the end of 2010, and less Ohio POLR load served by FES beginning in June 2011. The increase in volumes purchased from non-affiliates in 2011 is primarily due to Met-Ed's and Penelec's generation procurement plan effective January 1, 2011 and more Ohio POLR load served by non-affiliates, partially offset by a decrease in RPM expenses in the PJM market.

Source of Change in Purchased Power	Increase (Decrease) (In millions)
Pre-merger companies:	
Purchases from non-affiliates:	
Change due to decreased unit costs	$(826)
Change due to increased volumes	515
	(311)
Purchases from FES:	
Change due to increased unit costs	165
Change due to decreased volumes	(1,601)
	(1,436)
Total pre-merger companies	(1,747)
Purchases by Allegheny companies	1,146
Net Decrease in Purchased Power Costs	$(601)

- Other operating expenses decreased $37 million, primarily due to the following:

Storm restoration maintenance and removal expenses increased $126 million primarily related to restoration associated with Hurricane Irene and an October 2011 East Coast snowstorm, primarily impacting the JCP&L and Met-Ed service territories. Approximately $120 million of the total costs were deferred for future recovery from customers.

Energy efficiency program costs, which are also recovered through rates, increased by $92 million.

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

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

Transmission expenses decreased $285 million primarily due to reduced congestion costs for Met-Ed and Penelec in 2011.

- Pensions and OPEB mark-to-market adjustment charges increased $132 million as a result of higher net actuarial losses.
- Depreciation expense increased $24 million primarily due to property additions since 2010.
- Net amortization of regulatory assets decreased $368 million primarily due to reduced net PJM transmission and transition cost recovery, the absence of a $35 million regulatory asset impairment recognized in 2010 associated with the filing of the Ohio Companies' ESP on March 23, 2010, and the deferral of recoverable costs from Hurricane Irene and the 2011 East Coast snowstorm, partially offset by increased energy efficiency cost recovery.
- General Taxes increased $10 million due to the absence of a favorable property tax settlement recognized in 2010.
- Impairments of long-lived assets totaling $87 million in 2011 resulted from the pending shutdown of three coal-fired plants in West Virginia.

The acquisition of the Allegheny companies resulted in the inclusion of the following operating expenses in 2011:

Operating Expenses - Allegheny	In Millions
Purchased power	$1,146
Fuel	268
Transmission	120
Amortization of regulatory assets, net	(21)
Pensions and OPEB mark-to-market adjustment	76
Other operating expenses	259
General taxes	109
Depreciation expense	163
Total Operating Expenses	$2,120

Other Expense —

Other expense increased $59 million in 2011 due to interest expense on debt of the Allegheny companies partially offset by higher investment income on OE's and TE's nuclear decommissioning trusts and increased capitalized interest.

Regulated Independent Transmission — 2011 Compared with 2010

Net income increased by $58 million in 2011 compared to 2010 due to earnings associated with TrAIL and PATH of $79 million, partially offset by decreased earnings for ATSI of $20 million.

Revenues —

Total revenues increased by $149 million principally due to revenues from TrAIL and PATH, which were acquired as part of the merger with Allegheny, partially offset by a decrease in ATSI revenues due to the transition from MISO to PJM and the completion of vegetation management cost recovery in May 2011.

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

Revenues by Transmission Asset Owner	2011	2010	Increase (Decrease)
	(In millions)		
ATSI	$207	$242	$(35)
TrAIL	170	—	170
PATH	14	—	14
Total Revenues	$391	$242	$149

Operating Expenses —

Total operating expenses increased by $33 million principally due to the addition of TrAIL and PATH in 2011.

Other Expense —

Other expense increased $24 million in 2011 due to additional interest expense associated with TrAIL.

Competitive Energy Services — 2011 Compared to 2010

Net income increased by $166 million in 2011 compared to 2010. The increase in net income was primarily due to a $569 million gain ($358 million net of tax) on the partial sale of FEV's interest in Signal Peak in 2011 and decreased impairments of long-lived assets. Partially offsetting this was a decrease in sales margins of $193 million, a $66 million increase in interest expense and a $55 million decrease in capitalized interest compared to 2010.

Revenues —

Total revenues increased $1.3 billion in 2011 compared to 2010, primarily due to an increase in direct and governmental aggregation sales and the inclusion of the Allegheny companies, partially offset by a decline in POLR and structured sales.

The increase in reported segment revenues resulted from the following sources:

Revenues by Type of Service	2011	2010	Increase (Decrease)
	(In millions)		
Direct and Governmental Aggregation	$3,785	$2,493	$1,292
POLR and Structured Sales	944	2,589	(1,645)
Wholesale	457	397	60
Transmission	108	77	31
RECs	67	74	(7)
Sale of OVEC participation interest	—	85	(85)
Other	173	161	12
Allegheny Companies	1,639	—	1,639
Total Revenues	$7,173	$5,876	$1,297

Allegheny Companies	
Direct and Government Aggregation	$84
POLR and Structured Sales	561
Wholesale	912
Transmission	88
Other	(6)
Total Revenues	$1,639

MWH Sales by Type of Service	2011	2010	Increase (Decrease)
	(In thousands)		
Direct	46,187	28,499	17,688
Government Aggregation	17,722	12,796	4,926
POLR and Structured Sales	15,340	50,358	(35,018)
Wholesale	2,916	5,391	(2,475)
Allegheny Companies	26,609	—	26,609
Total Sales	108,774	97,044	11,730

Allegheny Companies	
Direct	1,390
POLR	7,974
Structured Sales	1,492
Wholesale	15,753
Total Sales	26,609

The increase in direct and governmental aggregation revenues of $1.3 billion resulted from the acquisition of new residential, commercial and industrial customers, as well as new governmental aggregation contracts with communities in Ohio and Illinois that provide generation to approximately 1.8 million residential and small commercial customers at the end of 2011 compared to approximately 1.5 million customers at the end of 2010. Increases in direct sales volume were partially offset by lower unit prices.

The decrease in POLR and structured sales revenues of $1.6 billion was due to lower sales volumes to Met-Ed, Penelec and the Ohio Companies, partially offset by increased sales to non-affiliates and higher unit prices to the Pennsylvania Companies. The decline in POLR sales reflects our focus on more profitable sales channels.

Wholesale revenues increased $60 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, partially offset by increased short-term transactions in PJM. In addition, capacity revenues earned by units that moved to PJM from MISO were partially offset by losses on financially settled sales contracts.

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

Source of Change in Direct and Governmental Aggregation	Increase(Decrease) (In millions)
Direct Sales:	
Effect of increase in sales volumes	$1,034
Change in prices	(75)
	959
Governmental Aggregation:	
Effect of increase in sales volumes	319
Change in prices	14
	333
Net Increase in Direct and Government Aggregation Revenues	$1,292

Source of Change in POLR and Structured Revenues	Increase (Decrease) (In millions)
Effect of decrease in sales volumes	$(1,800)
Change in prices	155
	$(1,645)

Source of Change in Wholesale Revenues	Increase(Decrease) (In millions)
Effect of decrease in sales volumes	$(182)
Change in prices	242
	$60

Operating Expenses —

Total operating expenses increased $1.5 billion in 2011. Excluding the Allegheny companies, total operating expenses decreased $98 million compared to 2010, due to the following factors:

- Fuel costs decreased $177 million in 2011 compared to 2010 primarily due to cash received from assigning a substantially below-market, long-term fossil contract to a third party. In connection with its merger integration initiatives and risk management strategy, FirstEnergy continues to evaluate opportunities with respect to its commodity contracts. As a result of the assignment, FirstEnergy entered into a new long-term contract with another supplier for replacement fuel based on current market prices. Excluding the assignment, fuel costs decreased $54 million in 2011 compared to 2010 due to decreased volumes consumed ($115 million), partially offset by higher unit prices ($61 million). The decrease in fossil fuel expense reflects lower generation needed to satisfy sales requirements. Lower fossil fuel expenses were partially offset by a $22 million increase in nuclear fuel costs, which rose principally due to higher nuclear fuel unit prices following the refueling outages that occurred in 2010 and 2011.
- Purchased power costs decreased $382 million as lower volumes ($649 million) were partially offset by higher unit prices ($267 million). The decrease in volume primarily relates to the expiration at the end of 2010 of a 1,300 MW third party contract associated with serving Met-Ed and Penelec.
- Fossil operating costs increased $36 million due primarily to higher labor, contractor and material costs resulting from an increase in planned and unplanned outages, which were partially offset by reduced losses from the sale of excess coal.
- Nuclear operating costs increased $53 million primarily due to Perry and Beaver Valley Unit 2 refueling outages in 2011. While Davis-Besse had a refueling outage in 2010 and an outage in 2011 to replace the reactor vessel head, the work performed on both outages was largely capital-related.
- Transmission expenses increased $249 million due primarily to higher congestion, network and line loss expenses.
-

Depreciation expense increased $20 million principally due to the completion of the Sammis projects at the end of 2010.

- General taxes increased $36 million due to an increase in revenue-related taxes.

- Impairments of long-lived assets decreased $85 million compared to last year. The 2011 charges are due to the pending shutdown of six unregulated, coal-fired generating units; charges in 2010 related to operational changes at certain smaller coal-fired units.
- Other operating expenses increased $152 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 $64 million increase in pensions and OPEB mark-to-market adjustment charges from higher net actuarial losses; a $10 million increase in other mark-to-market adjustments; an $18 million increase in agent fees due to rapid growth in FES' retail business; and a $17 million increase in intercompany billings. The intercompany billings increased due to higher merger-related costs, partially offset by lower leasehold costs from the Ohio Companies.

The inclusion of the Allegheny companies' operations added $1.6 billion to operating expenses as shown in the following table:

Source of Operating Expense Changes	Increase (Decrease)
	(In millions)
Allegheny Companies	
Fuel	$794
Purchased power	149
Fossil operation and maintenance	152
Transmission	198
Pensions and OPEB mark-to-market adjustment	44
Other mark-to-market	4
Depreciation	111
General taxes	40
Other	96
Total operating expenses	$1,588

Other Expense —

Total other expense in 2011 was $453 million lower than 2010, primarily due to a $569 million gain on the partial sale of FEV's interest in Signal Peak and an increase in nuclear decommissioning trust investment income of $5 million, partially offset by a $121 million increase in net interest expense. The net interest expense increase in 2011 from 2010 resulted from lower capitalized interest due to the completion of major environmental projects in 2010.

Other — 2011 Compared to 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 $99 million decrease in earnings available to FirstEnergy in 2011 compared to 2010. The decrease resulted primarily from decreased capitalized interest and increased depreciation expense resulting from the completed construction projects placed into service ($58 million), decreased investment income ($16 million), an asset impairment charge in the first quarter of 2011 ($11 million) and higher income taxes ($13 million).

Summary of Results of Operations — 2010 Compared with 2009

Financial results for FirstEnergy’s major business segments in 2010 and 2009 were as follows:

2010 Financial Results	Regulated Distribution (In millions)	Competitive Energy Services	Regulated Independent Transmission	Other and Reconciling Adjustments	FirstEnergy Consolidated
Revenues:					
External					
Electric	$9,271	$3,252	$—	$—	$12,523
Other	300	323	242	(123)	742
Internal	139	2,301	—	(2,366)	74
Total Revenues	9,710	5,876	242	(2,489)	13,339
Operating Expenses:					
Fuel	—	1,432	—	—	1,432
Purchased power	5,273	1,724	—	(2,373)	4,624
Other operating expenses	1,320	1,393	61	(78)	2,696
Pensions and OPEB mark-to-market adjustment	82	107	(2)	3	190
Provision for depreciation	433	284	37	14	768
Amortization of regulatory assets, net	712	—	10	—	722
General taxes	605	124	30	17	776
Impairment of long-lived assets	—	388	—	—	388
Total Operating Expenses	8,425	5,452	136	(2,417)	11,596
Operating Income	1,285	424	106	(72)	1,743
Other Income (Expense):					
Investment income	102	51	—	(36)	117
Interest expense	(500)	(232)	(22)	(91)	(845)
Capitalized interest	4	95	2	64	165
Total Other Expense	(394)	(86)	(20)	(63)	(563)
Income Before Income Taxes	891	338	86	(135)	1,180
Income taxes	338	128	32	(36)	462
Net Income	553	210	54	(99)	718
Loss attributable to noncontrolling interest	—	—	—	(24)	(24)
Earnings available to FirstEnergy Corp.	$553	$210	$54	$(75)	$742

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2009 Financial Results	Regulated Distribution	Competitive Energy Services	Regulated Independent Transmission	Other and Reconciling Adjustments	FirstEnergy Consolidated
	(In millions)				
Revenues:					
External					
Electric	$10,585	$1,447	$—	$—	$12,032
Other	331	481	223	(111)	924
Internal	—	2,843	—	(2,826)	17
Total Revenues	10,916	4,771	223	(2,937)	12,973
Operating Expenses:					
Fuel	—	1,153	—	—	1,153
Purchased power	6,560	996	—	(2,826)	4,730
Other operating expenses	1,257	1,332	56	(94)	2,551
Pensions and OPEB mark-to-market adjustment	166	151	2	2	321
Provision for depreciation	426	279	37	15	757
Amortization of regulatory assets, net	1,006	—	13	—	1,019
General taxes	589	112	32	20	753
Impairment of long-lived assets	—	6	—	—	6
Total Operating Expenses	10,004	4,029	140	(2,883)	11,290
Operating Income	912	742	83	(54)	1,683
Other Income (Expense):					
Investment income	141	121	—	(58)	204
Interest expense	(478)	(174)	(19)	(307)	(978)
Capitalized interest	3	62	1	65	131
Total Other Expense	(334)	9	(18)	(300)	(643)
Income Before Income Taxes	578	751	65	(354)	1,040
Income taxes	243	305	26	(390)	184
Net Income	335	446	39	36	856
Loss attributable to noncontrolling interest	—	—	—	(16)	(16)
Earnings available to FirstEnergy Corp.	$335	$446	$39	$52	$872

Changes Between 2010 and 2009 Financial Results Increase (Decrease)	Regulated Distribution	Competitive Energy Services	Regulated Independent Transmission	Other and Reconciling Adjustments	FirstEnergy Consolidated
	(In millions)				
Revenues:					
External					
Electric	$(1,314)	$1,805	$—	$—	$491
Other	(31)	(158)	19	(12)	(182)
Internal	139	(542)	—	460	57
Total Revenues	(1,206)	1,105	19	448	366
Operating Expenses:					
Fuel	—	279	—	—	279
Purchased power	(1,287)	728	—	453	(106)
Other operating expenses	63	61	5	16	145
Pensions and OPEB mark-to-market adjustment	(84)	(44)	(4)	1	(131)
Provision for depreciation	7	5	—	(1)	11
Amortization of regulatory assets, net	(294)	—	(3)	—	(297)
General taxes	16	12	(2)	(3)	23
Impairment of long-lived assets	—	382	—	—	382
Total Operating Expenses	(1,579)	1,423	(4)	466	306
Operating Income	373	(318)	23	(18)	60
Other Income (Expense):					
Gain on partial sale of Signal Peak	—	—	—	—	—
Investment income	(39)	(70)	—	22	(87)
Interest expense	(22)	(58)	(3)	216	133
Capitalized interest	1	33	1	(1)	34
Total Other Expense	(60)	(95)	(2)	237	80
Income Before Income Taxes	313	(413)	21	219	140
Income taxes	95	(177)	6	354	278
Net Income	218	(236)	15	(135)	(138)
Loss attributable to noncontrolling interest	—	—	—	(8)	(8)
Earnings available to FirstEnergy Corp.	$218	$(236)	$15	$(127)	$(130)

Regulated Distribution — 2010 Compared with 2009

Net income increased by $218 million in 2010 compared to 2009, primarily due to CEI's $216 million regulatory asset impairment in 2009 and lower pensions and OPEB costs, partially offset by increases in other operating expenses. Lower generation revenues were offset by lower purchased power expenses.

Revenues —

The decrease in total revenues resulted from the following sources:

Revenues by Type of Service	2010	2009	Increase (Decrease)
	(In millions)		
Distribution services	$3,629	$3,419	$210
Generation:			
Retail	4,457	5,764	(1,307)
Wholesale	702	752	(50)
Total generation sales	5,159	6,516	(1,357)
Transmission	596	805	(209)
Other	326	176	150
Total Revenues	$9,710	$10,916	$(1,206)

The increase in distribution deliveries by customer class is summarized in the following table:

Electric Distribution MWH Deliveries	Increase
Residential	5.9%
Commercial	2.8%
Industrial	8.4%
Total Distribution MWH Deliveries	5.6%

Higher deliveries to residential and commercial customers reflect increased weather-related usage due to a 70% increase in cooling degree days in 2010 compared to 2009, partially offset by a 4% decrease in heating degree days for the same period. In the industrial sector, MWH deliveries increased primarily to major automotive customers (16%), refinery customers (7%) and steel customers (38%). The increase in distribution service revenues also reflects Met-Ed's, Penelec's and Penn's recovery of the Pennsylvania EE&C as approved by the PPUC in March 2010 and the accelerated recovery of deferred distribution costs in Ohio, partially offset by a reduction in the transition rate for CEI effective June 1, 2009.

The following table summarizes the price and volume factors contributing to the $1.4 billion decrease in generation revenues in 2010 compared to 2009:

Source of Change in Generation Revenues	Increase (Decrease)
	(In millions)
Retail:	
Effect of decrease in sales volumes	$(1,435)
Change in prices	128
	(1,307)
Wholesale:	
Effect of decrease in sales volumes	(64)
Change in prices	14
	(50)
Net Decrease in Generation Revenues	$(1,357)

The decrease in retail generation sales volumes was primarily due to an increase in customer shopping in the Ohio Companies' service territories. Total generation MWH provided by alternative suppliers as a percentage of total MWH deliveries by the Ohio Companies increased to 62% in 2010 from 17% in 2009.

The decrease in wholesale generation revenues reflected lower RPM revenues for Met-Ed and Penelec in the PJM market.

Transmission revenues decreased $209 million primarily due to the termination of the Ohio Companies' transmission tariff effective June 1, 2009; transmission costs are now a component of the cost of generation established under the May 2009 Ohio CBP.

Other revenues increased by $150 million primarily due to Met-Ed's and Penelec's PSA with FES in 2010, resulting in increased capacity revenues.

Operating Expenses —

Total operating expenses decreased by $1.6 billion due to the following:

- Purchased power costs were $1.3 billion lower in 2010, largely due to lower volume requirements. The decrease in volumes from non-affiliates resulted principally from the termination of a third-party supply contract for Met-Ed and Penelec in January 2010 and from the increase in customer shopping in the Ohio Companies’ service territories. The decrease in purchases from FES also resulted from the increase in customer shopping in Ohio.
- An increase in purchased power unit costs from non-affiliates in 2010 resulted from higher capacity prices in the PJM market for Met-Ed and Penelec. A decrease in unit costs for purchases from FES was principally due to the lower weighted average unit price per MWH established under the May 2009 CBP auction for the Ohio Companies effective June 1, 2009.

Source of Change in Purchased Power	Increase (Decrease) (In millions)
Purchases from non-affiliates:	
Change due to increased unit costs	$709
Change due to decreased volumes	(1,489)
	(780)
Purchases from FES:	
Change due to decreased unit costs	(257)
Change due to decreased volumes	(250)
	(507)
Net Decrease in Purchased Power Costs	$(1,287)

- Transmission expenses increased $70 million primarily due to higher PJM network transmission expenses and congestion costs for Met-Ed and Penelec, partially offset by lower MISO network transmission expenses that are reflected in the generation rate established under the May 2009 Ohio CBP. Met-Ed and Penelec defer or amortize the difference between revenues from their transmission rider and transmission costs incurred, resulting in no material effect on current period earnings.
- Energy efficiency program costs, which are also recovered through rates, increased $41 million in 2010 compared to 2009.
- Labor and employee benefit expenses decreased by $30 million due to lower payroll costs resulting from staffing reductions implemented in 2009, and restructuring expenses recognized in 2009.
- Pensions and OPEB mark-to-market adjustment charges decreased by $84 million primarily resulting from lower net actuarial losses.
- Expenses for economic development commitments related to the Ohio Companies’ ESP were lower by $11 million in 2010 compared to 2009.
- Depreciation expense increased $7 million due to property additions since 2009.
- Amortization of regulatory assets decreased $294 million due primarily to the absence of the $216 million impairment of CEI’s regulatory assets in 2009, reduced net MISO and PJM transmission cost amortization and reduced CTC amortization for Met-Ed and Penelec, partially offset by increased amortization associated with the accelerated recovery of deferred distribution costs in Ohio and a $35 million regulatory asset impairment in 2010 associated with the Ohio Companies’ ESP and the absence of CEI’s purchased power cost deferrals that ended in early 2009.
- General taxes increased $16 million principally due to a benefit relating to Ohio MWH excise taxes that was recognized in 2009 and applicable to prior years.

Other Expense —

Other expense increased $60 million in 2010 compared to 2009 primarily due to lower investment income on OE's and TE's nuclear decommissioning trusts ($37 million) and higher net interest expense associated with debt issuances during 2009 ($23 million).

Regulated Independent Transmission — 2010 Compared with 2009

Net income increased by $15 million in 2010 compared to 2009 due to increased revenues.

Revenues —

Total revenues increased by $19 million principally due to higher peak loads in 2010 compared to 2009.

Operating Expenses —

Total operating expenses decreased by $4 million principally due to decreased property taxes and decreased pensions and OPEB costs primarily due to lower net actuarial losses.

Other Expense —

Other expense increased $2 million in 2010 due to higher interest expense associated with higher average debt levels in 2010 compared to 2009.

Competitive Energy Services — 2010 Compared to 2009

Net income decreased by $235 million in 2010 compared to 2009. The decrease in net income was primarily due to $382 million of impairment charges ($240 million net of tax) in 2010. In addition, FES sold a 6.65% participation interest in OVEC in 2010 compared to a 9% interest in 2009, accounting for $105 million of the reduction in net income. Investment income from nuclear decommissioning trusts was also lower in 2010. These reductions were partially offset by an increase in sales margins.

Revenues —

Total revenues increased $1.1 billion in 2010 compared to the same period in 2009 primarily due to an increase in direct and governmental aggregation sales and sales of RECs, partially offset by decreases in POLR sales to the Ohio Companies, other wholesale sales and the reduced OVEC participation interest sale in 2010.

The increase in reported segment revenues resulted from the following sources:

Revenues by Type of Service	2010	2009	Increase (Decrease)
	(In millions)		
Direct and Governmental Aggregation	$2,493	$779	$1,714
POLR	2,589	2,863	(274)
Wholesale	397	632	(235)
Transmission	77	73	4
RECs	74	17	57
Sale of OVEC participation interest	85	252	(167)
Other	161	155	6
Total Revenues	$5,876	$4,771	$1,105

The increase in direct and governmental aggregation revenues of $1.7 billion resulted from increased revenue from the acquisition of new commercial and industrial customers as well as from new governmental aggregation contracts with communities in Ohio that provide generation to 1.5 million residential and small commercial customers at the end of 2010 compared to approximately 600,000 customers at the end of 2009. Increases in direct sales were partially offset by lower unit prices. Sales to residential and small commercial customers were also bolstered by summer weather in the delivery area that was significantly warmer than in 2009.

The decrease in POLR revenues of $274 million was due to lower sales volumes and lower unit prices to the Ohio Companies, partially offset by increased sales volumes and higher unit prices to Met-Ed and Penelec. The lower sales volumes and unit prices to the Ohio Companies in 2010 reflected the results of the May 2009 CBP. The increased revenues to Met-Ed and Penelec resulted from FES supplying volumes previously supplied through a third-party contract, and at prices that were slightly higher than in 2009.

Other wholesale revenues decreased $235 million due to reduced volumes, partially offset by higher prices. Lower sales volumes in MISO were due to available capacity serving increased retail sales in Ohio partially offset by increased sales under bilateral agreements in PJM.

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

Source of Change in Direct and Governmental Aggregation	Increase (Decrease) (In millions)
Direct Sales:	
Effect of increase in sales volumes	$1,080
Change in prices	(87)
	993
Government Aggregation:	
Effect of increase in sales volumes	707
Change in prices	14
	721
Net Increase in Direct and Governmental Aggregation Revenues	$1,714

Source of Change in Wholesale Revenues	Increase (Decrease) (In millions)
POLR:	
Effect of increase in sales volumes	$38
Change in prices	(312)
	(274)
Other Wholesale:	
Effect of decrease in sales volumes	(344)
Change in prices	109
	(235)
Net Decrease in Wholesale Revenues	$(509)

Operating Expenses —

Total operating expenses increased $1.4 billion in 2010 due to the following factors:

- Fuel costs increased $279 million in 2010 compared to 2009 primarily due to increased volumes consumed ($217 million) and higher unit prices ($62 million). The higher volumes consumed in 2010 were due to increased sales to direct and governmental aggregation customers, improved economic conditions and improved generating unit availability. The increase in unit prices was due primarily to increased coal transportation costs and to higher nuclear fuel unit prices following the refueling outages that occurred in 2009 and 2010.
- Purchased power costs increased $728 million. Increased volumes purchased primarily relate to the assumption of a 1,300 MW third party contract from Met-Ed and Penelec.
- Fossil operating costs decreased $12 million due primarily to lower labor and professional and contractor costs, which were partially offset by reduced gains from the sale of emission allowances and excess coal.
- Nuclear operating costs decreased $21 million due primarily to lower labor, consulting and contractor costs partially offset by increased nuclear property insurance and employee benefit costs. The year 2010 had one less refueling outage and fewer extended outages than the same period of 2009.
- Transmission expenses increased $25 million due primarily to increased costs in MISO of $170 million from higher network, ancillary and congestion costs, partially offset by lower PJM transmission expenses of $145 million due to lower congestion costs.
- Depreciation expense increased $5 million principally due to property additions that were placed in service since 2009.
- General taxes increased $12 million due to an increase in revenue-related taxes.
- Other operating expenses increased $406 million primarily due to a $382 million impairment charge ($240 million net of tax) related to operational changes at certain smaller coal-fired units. Expenses also increased for professional and contractor services, billings from affiliated service companies, uncollectible customer accounts and agent fees, as FES continued to grow its retail business.

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Other Expense —
Total other expense in 2010 was $95 million higher than the same period in 2009, primarily due to a $66 million decrease in nuclear decommissioning trust investment income and a $25 million increase in net interest expense from new long-term debt issued in late 2009 combined with the restructuring of outstanding PCRBs that occurred throughout 2009 and 2010.

Other — 2010 Compared to 2009
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 $127 million decrease in earnings available to FirstEnergy in 2010 compared to 2009. The decrease resulted primarily from increased income tax expense ($354 million) due in part to the absence of favorable tax settlements that occurred in 2009 ($200 million), partially offset by the absence of 2009 debt retirement costs in connection with the tender offer for holding company debt ($90 million), decreased interest expense associated with the debt retirement ($53 million) and increased investment income ($22 million).

CAPITAL RESOURCES AND LIQUIDITY
As of December 31, 2011, FirstEnergy had $202 million of cash and cash equivalents available to fund investments, operations and capital expenditures.

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. In addition to internal sources to fund liquidity and capital requirements for 2012 and beyond, FirstEnergy expects to 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 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 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.

As of December 31, 2011, FirstEnergy's net deficit in working capital (current assets less current liabilities) was principally due to currently payable long-term debt, which, as of December 31, 2011, included the following:

Currently Payable Long-term Debt	(In millions)
Met-Ed, Penelec, FGCO and NGC PCRBs supported by bank LOCs (1)	$632
AE Supply unsecured note	503
FGCO and NGC unsecured PCRBs (1)	270
WP unsecured note	80
NGC collateralized lease obligation bonds	67
Sinking fund requirements	52
Other notes	17
	$1,621

(1) These PCRBs are classified as currently payable long-term debt solely because the applicable Interest rate mode permits individual debt holders to put the respective debt back to the issuer prior to maturity.

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Short-Term Borrowings

FirstEnergy had no significant short-term borrowings as of December 31, 2011, and short-term borrowings of approximately $700 million as of December 31, 2010. FirstEnergy's available liquidity as of January 31, 2012, was as follows:

Company	Type	Maturity	Commitment	Available Liquidity
			(In millions)	
FirstEnergy[1]	Revolving	June 2016	$2,000	$1,395
FES / AE Supply	Revolving	June 2016	2,500	2,498
TrAIL	Revolving	Jan. 2013	450	450
AGC	Revolving	Dec. 2013	50	—
		Subtotal	$5,000	$4,343
		Cash	—	49
		Total	$5,000	$4,392

(1) FE and the Utilities

Revolving Credit Facilities

FirstEnergy and FES / AE Supply Facilities

FirstEnergy and certain of its subsidiaries participate in two five-year syndicated revolving credit facilities with aggregate commitments of $4.5 billion (Facilities).

An aggregate amount of $2 billion is available to be borrowed under a syndicated revolving credit facility (FirstEnergy Facility), subject to separate borrowing sublimits for each borrower. The borrowers under the FirstEnergy Facility are FE, OE, Penn, CEI, TE, Met-Ed, 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 (FES/AE Supply Facility), subject to separate borrowing sublimits for each borrower.

Commitments under each of the 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 Facilities are available to each borrower separately and 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 Facilities are subject to the usual and customary provisions for acceleration upon the occurrence of events of default, including a cross-default for other indebtedness in excess of $100 million, as described further in Note 12, Capitalization.

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 December 31, 2011:

Borrower	Revolving Credit Facility Sub-Limit	Regulatory and Other Short-Term Debt Limitations	
	(In millions)		
FE	$2,000	—	(1)
FES	$1,500	—	(2)
AE Supply	$1,000	—	(2)
OE	$500	$500	
CEI	$500	$500	
TE	$500	$500	
JCP&L	$425	$411	(3)
Met-Ed	$300	$300	(3)
Penelec	$300	$300	(3)
West Penn	$200	$200	(3)
MP	$150	$150	(3)
PE	$150	$150	(3)
ATSI	$100	$100	
Penn	$50	$33	(3)

(1) No limitations.
(2) No limitation based upon blanket financing authorization from the FERC under existing open market tariffs.
(3) Excluding amounts which may be borrowed under the regulated companies' money pool.

The entire amount of the FES/AE Supply Facility and $700 million of the 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 Facilities and against the applicable borrower's borrowing sub-limit.

Each of the 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 December 31, 2011, FirstEnergy's and its subsidiaries' debt to total capitalization ratios (as defined under each of the Facilities) were as follows:

Borrower		
FirstEnergy	57.5	%
FES	51.4	%
OE	63.4	%
Penn	42.8	%
CEI	59.4	%
TE	62.7	%
JCP&L	43.6	%
Met-Ed	56.0	%
Penelec	56.6	%
ATSI	48.6	%
MP	56.6	%
PE	56.8	%
WP	52.1	%
AE Supply	38.5	%

As of December 31, 2011, FirstEnergy could issue additional debt of approximately $6.7 billion, or recognize a reduction in equity of approximately $3.6 billion, and remain within the limitations of the financial covenants required by its revolving credit facility.

The 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 subject to "pricing grids," whereby the borrower's cost of funds borrowed under the Facilities is related to the credit ratings of the company borrowing the funds.

AGC and TrAIL Revolving Credit Facilities

FirstEnergy also has established $500 million of revolving credit facilities that are available to TrAIL ($450 million) and AGC ($50 million) until January 2013 and December 2013, respectively.

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 65% of the sum of its debt and equity as of the last day of each calendar quarter through December 31, 2012. These provisions limit debt levels of these subsidiaries and also limit the net assets of each subsidiary that may be transferred to AE. As of December 31, 2011, the debt to total capitalization ratios for TrAIL and AGC (as defined under each of their credit facilities) were 48% and 51%, respectively.

As of December 31, 2011, TrAIL could issue additional debt of approximately $222 million, or recognize a reduction in equity of approximately $341 million and AGC could issue additional debt of approximately $39 million, or recognize a reduction in equity of approximately $61 million, and remain within the limitations of the financial covenants required by their credit facilities.

FirstEnergy Money Pools

FirstEnergy's regulated companies also have the ability to borrow from each other and the holding company to meet their short-term working capital requirements. A similar but separate arrangement exists among 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 during 2011 was 0.44% per annum for the regulated companies' money pool and 0.42% per annum for the unregulated companies' money pool.

Pollution Control Revenue Bonds

As of December 31, 2011, FirstEnergy's currently payable long-term debt included approximately $632 million (FES — $558 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 December 31, 2011:

LOC Bank	Aggregate LOC Amount(1) (In millions)	LOC Termination Date	Reimbursements of LOC Draws Due
UBS	$272	April 2014	April 2014
CitiBank N.A.	165	June 2014	June 2014
Wachovia Bank	153	March 2014	March 2014
The Bank of Nova Scotia	49	April 2014	Multiple dates(2)
Total	$639		

(1) Includes approximately $7 million of applicable interest coverage.

(2) Shorter of 6 months or LOC termination date.

During 2011, FirstEnergy redeemed or repurchased approximately $520.4 million principal amount of PCRBs, as summarized in the following table. Approximately $28.5 million of FGCO FMBs and $98.9 million of NGC FMBs associated with the PCRBs were returned for cancellation by the associated LOC providers.

Subsidiaries	Amount (In millions)

AE Supply	$53.0	(1)
FGCO	$198.2	(2)
NGC	$213.5	(2)
MP	$70.2	(1)

(1) Includes $14.4 million of PCRBs redeemed for which MP and AE Supply are co-obligors.

(2) Subject to market conditions, these PCRBs are being held for future remarketing.

Long-Term Debt Capacity

As of December 31, 2011, the Ohio Companies and Penn had the aggregate capability to issue approximately $2.7 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 $232 million and $20 million, respectively. As a result of the indenture provisions, TE cannot incur any additional secured debt. Met-Ed and Penelec had the capability to issue secured debt of approximately $376 million and $382 million, respectively, under provisions of their senior note indentures as of December 31, 2011. In addition, based upon their respective FMB indentures, net earnings and available bondable property additions as of December 31, 2011, MP, PE and WP had the capability to issue approximately $1.1 billion of additional FMBs in the aggregate. These companies may be further limited by the financial covenants of the Facilities and subject to current regulatory approvals and applicable statutory and/or charter limitations.

Based upon FGCO’s net earnings and available bondable property additions under its FMB indentures as of December 31, 2011, FGCO had the capability to issue $2.1 billion of additional FMBs under the terms of that indenture. Based upon NGC’s net earnings and available bondable property additions under its FMB indenture as of December 31, 2011, NGC had the capability to issue $2.0 billion of additional FMBs under the terms of that indenture.

FirstEnergy’s access to capital markets and costs of financing are influenced by the credit ratings of its securities. On March 21, 2011, S&P affirmed the ratings and stable outlook of FirstEnergy and its subsidiaries. On May 27, 2011, Fitch upgraded ratings for certain subsidiaries and revised the outlook to stable from negative for FirstEnergy and FES. On August 18, 2011, Moody's downgraded ratings for FES to Baa3 from Baa2 and revised FES' outlook to stable. On January 18, 2012, Moody's upgraded ratings for TrAIL to A3 from Baa2. The following table displays FirstEnergy’s and its subsidiaries’ debt credit ratings as of February 24, 2012:

	Senior Secured			Senior Unsecured		
Issuer	S&P	Moody’s	Fitch	S&P	Moody’s	Fitch
FE	—	—	—	BB+	Baa3	BBB
FES	—	—	—	BBB-	Baa3	BBB
AE Supply	—	—	—	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-	A3	A-
WP	BBB+	A3	A-	BBB-	Baa2	BBB+

See Note 12, Capitalization of the Combined Notes to the Consolidated Financial Statements for additional information on FirstEnergy's and the Registrants' long-term debt and other long-term obligations that were outstanding as of December 31, 2011.

Changes in Cash Position

As of December 31, 2011, FirstEnergy had $202 million of cash and cash equivalents compared to approximately $1 billion as of December 31, 2010. As of December 31, 2011 and 2010, FirstEnergy had approximately $79 million and $13 million, respectively, of restricted cash included in other current assets on the Consolidated Balance Sheet. During 2011, FirstEnergy received $1.8 billion of cash dividends from its subsidiaries and paid $881 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 regulated distribution, regulated independent transmission and competitive energy services businesses (see Results of Operations above). Net cash provided from operating activities was $3.1 billion in 2011, $3.1 billion in 2010 and $2.5 billion in 2009, as summarized in the following table:

Operating Cash Flows	2011	2010	2009
	(In millions)		
Net income	$869	$718	$856
Non-cash charges	2,424	2,343	2,095
Pension trust contributions	(372)	—	(500)
Working capital and other	142	15	14
	$3,063	$3,076	$2,465

The 2011 increase in non-cash charges is primarily due to increased pensions and OPEB mark-to-market adjustment charges from higher actuarial losses ($317 million), increased deferred taxes resulting from bonus depreciation ($348 million) and increased depreciation attributable to the acquired Allegheny companies ($353 million). These increases were partially offset by gains from the sale of assets, mostly due to the sale of Signal Peak ($543 million), and lower amortization of regulatory assets from reduced net PJM transmission cost and transition cost recovery ($393 million).

The 2011 increase in cash flows from working capital and other is primarily due to decreased receivables from higher customer collections ($324 million) partially offset by the absence of interest rate swap activity transacted in 2010 ($129 million).

Cash Flows From Financing Activities

In 2011, cash used for financing activities was $2,924 million compared to $983 million in 2010. The following table summarizes security issuances (net of any discounts) and redemptions:

Securities Issued or Redeemed	2011	2010	2009
		(In millions)	
New Issues			
PCRBs	$272	$740	$940
Long-term revolving credit	70	—	—
Senior secured notes	—	350	297
FMBs	—	—	398
Unsecured Notes	262	9	2,997
	$604	$1,099	$4,632
Redemptions			
PCRBs	$792	$741	$884
Long-term revolving credit	495	—	—
Senior secured notes	460	141	217
FMBs	15	32	1
Unsecured notes	147	101	1,508
	$1,909	$1,015	$2,610
Net repayment of short-term borrowings	$(700)	$(378)	$(1,246)

Cash Flows From Investing Activities

Cash used for investing activities in 2011 resulted from cash used for property additions, partially offset by the cash acquired in the Allegheny merger and proceeds from asset sales. The following table summarizes investing activities for 2011, 2010 and 2009 by business segment:

Summary of Cash Flows Provided from (Used for) Investing Activities	Property Additions	Investments	Other	Total
		(In millions)		
Sources (Uses)				
2011				
Regulated distribution	$(1,060)	$30	$(83)	$(1,113)
Competitive energy services	(927)	545	3	(379)
Regulated independent transmission	(192)	—	(3)	(195)
Cash received in Allegheny merger	—	590	—	590
Other and reconciling adjustments	(99)	223	17	141
Total	$(2,278)	$1,388	$(66)	$(956)
2010				
Regulated distribution	$(681)	$96	$17	$(568)
Competitive energy services	(1,159)	(43)	(51)	(1,253)
Regulated independent transmission	(64)	—	(4)	(68)
Other and reconciling adjustments	(59)	(30)	30	(59)
Total	$(1,963)	$23	$(8)	$(1,948)
2009				
Regulated distribution	$(718)	$39	$(45)	$(724)
Competitive energy services	(1,412)	(8)	(19)	(1,439)
Regulated independent transmission	(32)	—	(1)	(33)
Other and reconciling adjustments	(41)	(27)	79	11
Total	$(2,203)	$4	$14	$(2,185)

Net cash used for investing activities in 2011 decreased by $992 million compared to 2010. The decrease was principally due to cash acquired in the Allegheny merger ($590 million) and an increase in proceeds from asset sales ($723 million), partially offset by increased property additions ($315 million).

Our capital spending for 2012 is expected to be approximately $2.1 billion (excluding nuclear fuel). For 2013, we anticipate baseline capital expenditures of approximately $2.0 billion, which exclude any potential additional strategic opportunities, future mandated spending, energy efficiency or environmental spending relating to MATS. Planned capital initiatives are intended to promote reliability, improve operations, and support current environmental and energy efficiency directives. Our capital investments for additional nuclear fuel are expected to be $280 million and $219 million in 2012 and 2013, respectively.

CONTRACTUAL OBLIGATIONS

As of December 31, 2011, our estimated cash payments under existing contractual obligations that we consider firm obligations are as follows:

Contractual Obligations	Total	2012	2013-2014	2015-2016	Thereafter
	(In millions)				
Long-term debt(1)	$17,005	$1,605	$2,192	$2,688	$10,520
Interest on long-term debt(2)	12,071	975	1,804	1,548	7,744
Operating leases(3)	3,147	258	492	598	1,799
Fuel and purchased power(4)	32,877	3,598	5,589	4,616	19,074
Capital expenditures	2,715	681	984	638	412
Pension funding	1,030	—	231	799	—
Other(5)	263	28	105	47	83
Total	$69,108	$7,145	$11,397	$10,934	$39,632

(1) Excludes unamortized discounts and premiums and fair value accounting adjustments.

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

(3) See Note 6, Leases of the Combined Notes to the Consolidated Financial Statements.
(4) Amounts under contract with fixed or minimum quantities based on estimated annual requirements.
(5) Includes amounts for capital leases (see Note 6, Leases of the Combined Notes to the Consolidated Financial Statements) and contingent tax liabilities (see Note 5, Taxes of the Combined Notes to the Consolidated Financial Statements).

Excluded from the data shown above are estimates for the cash outlays stemming from power purchase contracts entered into by most of the Utilities and under which they procure the power supply necessary to provide generation service to their customers who do not choose an alternative supplier. The exact amounts will be determined by future customer behavior and consumption levels, but based on numerous planning assumptions, management estimates an amount of $5.4 billion in 2012, $1.8 billion of which relates to contracts with FES.

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. 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 credit support to various providers for the financing or refinancing by subsidiaries of costs related to the acquisition of property, plant and equipment. These agreements include provisions for parent guarantees, surety bonds and/or LOCs to be issued by FirstEnergy on behalf of one or more of its subsidiaries. Additionally, certain contracts may contain collateral provisions that are contingent upon either FirstEnergy's or its subsidiaries' credit ratings.

As of December 31, 2011, FirstEnergy's maximum exposure to potential future payments under outstanding guarantees and other assurances approximated $3.7 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)	$268
LOC (long-term debt) - interest coverage(2)	5
OVEC obligations	300
Other(3)	301
	874
Subsidiaries' Guarantees	
Energy and Energy-Related Contracts	141
LOC (long-term debt) - interest coverage(2)	2
FES' guarantee of NGC's nuclear property insurance	79
FES' guarantee of FGCO's sale and leaseback obligations	2,286
Other	12
	2,520
Surety Bonds	151
LOCs(4)	189
	340
Total Guarantees and Other Assurances	$3,734

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

(2) Reflects the interest coverage portion of LOCs issued in support of floating rate PCRBs with various maturities. The principal amount of floating-rate PCRBs of $632 million is reflected in currently payable long-term debt on FirstEnergy's consolidated balance sheets.

(3) Includes guarantees of $95 million for nuclear decommissioning funding assurances, $161 million supporting OE's sale and leaseback arrangement, and $36 million for railcar leases.

(4) Includes $36 million issued for various terms pursuant to capacity available under FirstEnergy's revolving credit facility, $116 million pledged in connection with the sale and leaseback of Beaver Valley Unit 2 by OE and $37 million pledged in connection with the sale and leaseback of Perry by OE.

Most of FirstEnergy's surety bonds are backed by various indemnities common within the insurance industry. Surety bonds and related guarantees of $151 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.

While the types of guarantees discussed above are normally parental commitments for the future payment of subsidiary obligations, subsequent to the occurrence of a senior unsecured credit rating downgrade to below S&P's BBB- and Moody's Baa3 and lower, or a “material adverse event,” the immediate posting of collateral or accelerated payments may be required of the subsidiary. As of December 31, 2011, FirstEnergy’s exposure to additional credit contingent contractual obligations was $636 million, as shown below:

Collateral Provisions	FES	AE Supply	Utilities	Total
	(In millions)			
Credit rating downgrade to below investment grade (1)	$468	$8	$57	$533
Material adverse event (2)	31	60	12	103
Total	$499	$68	$69	$636

(1) Includes $205 million and $47 million that are also considered accelerations of payment or funding obligations for FES and the Utilities, respectively.

(2) Includes $31 million that is also considered an acceleration of payment or funding obligation at FES.

Certain bilateral non-affiliate contracts entered into by the Competitive Energy Services segment contain margining provisions that require posting of collateral. Based on FES' and AE Supply's power portfolios exposure as of December 31, 2011, FES and AE Supply have posted collateral of $88 million and $1 million, respectively. Depending on the volume of forward contracts and future price movements, higher amounts for margining could be required.

Not included in the preceding information is potential collateral arising from the PSAs between FES or AE Supply and affiliated utilities in the Regulated Distribution Segment. As of December 31, 2011, neither FES nor AE Supply had any collateral posted with their affiliates. In the event of a senior unsecured credit rating downgrade to below S&P's BB- or Moody's Ba3, FES and AE Supply would be required to post $49 million and $24 million, respectively.

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 previously shared ownership in the borrowers with FEV, have provided a guaranty of the borrowers' obligations under the facility. On October 18, 2011, FEV sold a portion of its ownership interest in Signal Peak and Global Rail (see Note 8, Variable Interest Entities). Following the sale, FirstEnergy, WMB Loan Ventures, LLC and WMB Loan Ventures II, LLC, together with Global Mining Group, LLC and Global Holding will continue to guarantee the borrowers' obligations until either the facility is replaced with non-recourse financing (no later than June 30, 2012) or replaced with appropriate recourse financing no earlier than September 4, 2012, that provides for separate guarantees from each owner in proportion with each equity owner's percentage ownership in the joint venture. In addition, FEV, Global Mining Group, LLC and Global Holding, the entities that own direct and indirect equity interests in the borrowers, have pledged those interests to the lenders under the current facility as collateral.

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 December 31, 2011. See Note 6, Leases of the Combined Notes to the Consolidated Financial Statements for further information on FirstEnergy's and the Registrants' leases.

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. FirstEnergy's Risk Management 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.

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 9, Fair Value Measurements of the Combined Notes to the Consolidated Financial Statements).

Sources of information for the valuation of commodity derivative contracts assets and liabilities as of December 31, 2011 are summarized by year in the following table:

Source of Information- Fair Value by Contract Year	2012	2013	2014	2015	2016	Thereafter	Total
	(In millions)						
Prices actively quoted[1]	$—	$—	$—	$—	$—	$—	$—
Other external sources[2]	(211)	(51)	(32)	(22)	—	—	(316)
Prices based on models	(21)	—	—	—	8	31	18
Total[3]	$(232)	$(51)	$(32)	$(22)	$8	$31	$(298)

(1) Represents exchange traded New York Mercantile Exchange futures and options.
(2) Primarily represents contracts based on broker and IntercontinentalExchange quotes.
(3) Includes $(301) million in non-hedge commodity derivative contracts that are primarily related to NUG contracts. NUG contracts are 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 December 31, 2011, an adverse 10% change in commodity prices would decrease net income by approximately $13 million during the next 12 months.

Interest Rate Risk

FirstEnergy's exposure to fluctuations in market interest rates is reduced since a significant portion of debt has fixed interest rates, as noted in the table below. FirstEnergy is subject to the inherent interest rate risks related to refinancing maturing debt by issuing new debt securities. As discussed in Note 6, Leases of the Combined Notes to the Consolidated Financial Statements, FirstEnergy's investments in capital trusts effectively reduce future lease obligations, also reducing interest rate risk.

Comparison of Carrying Value to Fair Value

Year of Maturity	2012	2013	2014	2015	2016	There-after	Total	Fair Value
	(In millions)							
Assets:								
Investments Other Than Cash and Cash Equivalents:								
Fixed Income	$89	$100	$110	$76	$23	$2,008	$2,406	$2,456
Average interest rate	8.8%	8.9%	9.0%	9.5%	10.3%	5.4%	6.0%	
Liabilities:								
Long-term Debt:								
Fixed rate	$751	$964	$866	$1,330	$891	$11,628	$16,430	$18,585
Average interest rate	7.3%	5.9%	5.4%	4.7%	5.9%	6.2%	6.1%	
Variable rate		$150				$585	$735	$735
Average interest rate		1.8%				0.1%	0.4%	

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 December 31, 2011, the FirstEnergy pension plan was invested in approximately 19% of equity securities, 48% of fixed income securities, 21% of absolute return strategies, 6% of real estate, 2% 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 2011, FirstEnergy made pre-tax contributions to its qualified pension plans of $372 million. FirstEnergy made an additional $600 million pre-tax contribution to the qualified pension plan on January 5, 2012. NDT funds have been established to satisfy NGC’s and certain of the Utilities’ nuclear decommissioning obligations. As of December 31, 2011, approximately 79% of the funds were invested in fixed income securities, 12% of the funds were invested in equity securities and 9% 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 $1,699 million, $258 million and $207 million for fixed income securities, equity securities and short-term investments, respectively, as of December 31, 2011, excluding ($52) million of net receivables, payables and accrued income. A hypothetical 10% decrease in prices quoted by stock exchanges would result in a $26 million reduction in fair value as of December 31, 2011. The decommissioning trusts of JCP&L, Met-Ed and Penelec 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 recognized in earnings the unrealized losses on available-for-sale securities held in their NDT as OTTI. A decline in the value of FirstEnergy’s NDT or a significant escalation in estimated decommissioning costs could result in additional funding requirements. During 2011, approximately $1 million, $4 million and $1 million was contributed to the NDTs of JCP&L, OE and TE, respectively. FENOC has submitted a $95 million parental guarantee to the NRC for a short-fall in nuclear decommissioning funding to Beaver Valley Unit 1 and Perry.

CREDIT RISK

Credit risk is defined as the risk that a counterparty to a transaction will be unable to fulfill its contractual obligations. FirstEnergy evaluates the credit standing of a prospective counterparty based on the prospective counterparty's financial condition. FirstEnergy may impose specified collateral requirements and use standardized agreements that facilitate the netting of cash flows. FirstEnergy monitors the financial conditions of existing counterparties on an ongoing basis. An independent risk management group oversees credit risk.

Wholesale Credit Risk

FirstEnergy measures wholesale credit risk as the replacement cost for derivatives in power, natural gas, coal and emission allowances, adjusted for amounts owed to or due from counterparties for settled transactions. The replacement cost of open positions represents unrealized gains, net of any unrealized losses, where FirstEnergy has a legally enforceable right of set-off. FirstEnergy monitors and manages the credit risk of wholesale marketing, risk management and energy transacting operations through credit policies and procedures, which include an established credit approval process, daily monitoring of counterparty credit limits, the use of credit mitigation measures such as margin, collateral and the use of master netting agreements. 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).

Retail Credit Risk

FirstEnergy is exposed to retail credit risk through competitive electricity activities, which serve residential, commercial and industrial companies. Retail credit risk results when customers default on contractual obligations or fail to pay for service rendered. This risk represents the loss that may be incurred due to the nonpayment of customer accounts receivable balances, as well as the loss from the resale of energy previously committed to serve customers. Retail credit risk is managed through established credit approval policies, monitoring customer exposures and the use of credit mitigation measures such as deposits in the form of LOCs, cash or prepayment arrangements.

Retail credit quality is dependent on the economy and the ability of customers to manage through unfavorable economic cycles and other market changes. If the business environment were to be negatively affected by changes in economic or other market conditions, FirstEnergy's retail credit risk may be adversely impacted.

REGULATORY MATTERS

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.

Net regulatory assets on FirstEnergy's and the Utility Registrants' Consolidated Balance Sheets are comprised of the following:

Regulatory Assets	FirstEnergy	OE	CEI	TE	JCP&L	Met-Ed	Penelec
	(In millions)						
December 31, 2011							
Regulatory transition costs	$608	$—	$—	$—	$424	$105	$79
Customer receivables for future income taxes	508	42	1	2	29	129	145
Nuclear decommissioning, decontamination and spent fuel disposal costs	(210)	—	—	—	(44)	(99)	(67)
Asset removal costs	(240)	(34)	(60)	(23)	(147)	—	—
PJM transmission costs	340	(3)	(3)	(1)	—	181	63
Deferred generation costs	382	125	224	37	—	(23)	(11)
Distribution costs	267	146	73	48	—	—	—
Other	375	87	60	7	146	36	—
Total	$2,030	$363	$295	$70	$408	$329	$209
December 31, 2010							
Regulatory transition costs	$770	$—	$—	$—	$591	$131	$43
Customer receivables for future income taxes	328	52	2	1	30	113	130
Nuclear decommissioning, decontamination and spent fuel disposal costs	(184)	—	—	—	(31)	(92)	(61)
Asset removal costs	(237)	(24)	(47)	(19)	(147)	—	—
PJM transmission costs	183	—	—	—	—	131	52
Deferred generation costs	386	125	226	35	—	—	—
Distribution costs	426	216	155	55	—	—	—
Other	158	34	34	1	71	13	(1)
Total	$1,830	$403	$370	$73	$514	$296	$163

Additionally, FirstEnergy had $381 million of net regulatory liabilities as of December 31, 2011, including $366 million of net regulatory liabilities attributable to Allegheny that are primarily related to asset removal costs. Net regulatory liabilities are classified within Other Noncurrent Liabilities on the Consolidated Balance Sheets. Regulatory assets that do not earn a current return as of December 31, 2011 totaled approximately $413 million. Regulatory assets that do not earn a return are primarily comprised of certain regulatory transition and PJM transmission costs for Met-Ed and Penelec of $182 million and $115 million, respectively, that are expected to be recovered by 2020, and certain storm damage costs and pension and OPEB costs incurred by JCP&L of $122 million that are expected to be recovered by 2026.

RELIABILITY MATTERS

Federally-enforceable mandatory reliability standards apply to the bulk electric system and impose certain operating, record-keeping and reporting requirements on the Utilities, FES, AE Supply, FGCO, FENOC, ATSI and TrAIL. The NERC is the ERO designated by FERC to establish and enforce these reliability standards, although NERC has delegated day-to-day implementation and enforcement of these reliability standards to eight regional entities, including RFC. All of FirstEnergy's facilities are located within the RFC region. FirstEnergy actively participates in the NERC and RFC 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 RFC.

FirstEnergy believes that it 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 RFC. Moreover, it is clear that the NERC, RFC 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. 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, the NERC may take with respect to this matter.

On August 23, 2010, FirstEnergy self-reported to RFC 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, RFC issued a notice of enforcement to investigate the incident. FirstEnergy submitted a data response to RFC on September 27, 2010. On July 8, 2011, RFC and Met-Ed signed a settlement agreement to resolve all outstanding issues related to the vegetation encroachment event. The settlement calls for Met-Ed to pay a penalty of $650,000, and for FirstEnergy to perform certain mitigating actions. These mitigating actions include inspecting FirstEnergy's transmission system using LiDAR technology, and reporting the results of inspections, and any follow-up work, to RFC. FirstEnergy was performing the LiDAR work in response to certain other industry directives issued by NERC in 2010. NERC subsequently approved the settlement agreement and, on September 30, 2011, submitted the approved settlement to FERC for final approval. FERC approved the settlement agreement on October 28, 2011. Met-Ed subsequently paid the $650,000 penalty and, on December 31, 2011, RFC sent written notice that this matter has been closed.

In 2011, RFC performed routine compliance audits of parts of FirstEnergy's bulk-power system and generally found the audited systems and process to be in full compliance with all audited reliability standards. RFC will perform additional audits in 2012.

MARYLAND

By statute enacted in 2007, the obligation of Maryland utilities to provide SOS to residential and small commercial customers, in exchange for recovery of their costs plus a reasonable profit, was extended indefinitely. The legislation also established a 5-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 current settlement expires at the end of 2012 will depend on developments with respect to SOS in Maryland over the coming year, 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 proceeding.

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 December 2010, the MDPSC issued an order soliciting comments on a model RFP for solicitation of long-term energy commitments by Maryland electric utilities. PE and numerous other parties filed comments, and on September 29, 2011, the MDPSC issued an order requiring the utilities to issue the RFP crafted by the MDPSC by October 7, 2011. The RFPs were issued by the utilities as ordered by the MDPSC. The order, as amended, indicated that bids were due by January 20, 2012, and that the MDPSC would be the entity evaluating all bids. The Chairman of the MDPSC has stated publicly that several bids were received, but no other information was released. After receipt of further comments from interested parties, including PE, on January 13, 2012, a hearing on whether more generation is needed, irrespective of what bids may have been received, was held on January 31, 2012. There has been no further action on 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 for the PE programs for the period of 2009 to 2015 and would be recovered over that six year period. Meanwhile, after extensive meetings with the MDPSC Staff and other stakeholders, PE's plans for additional and improved programs for the period 2012-2014 were filed on August 31, 2011. The MDPSC held hearings on PE's and the other utilities' plans in October 2011, and on December 22, 2011, issued an order approving Potomac Edison's plan with various modifications and follow-up assignments. On January 23, 2012, PE filed a Request for Rehearing because additional facts not considered by the MDPSC demonstrate, among other things, that conservation voltage reduction program expenditures should be accorded cost recovery through the EmPOWER surcharge, as has been provided for all other EmPOWER programs as opposed to recovery of those expenditures being addressed in a future base rate case as the MDPSC found in its order.

In March 2009, the MDPSC issued an order temporarily suspending 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 collect data on payment plan and related issues and has adopted 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.
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 required to assess each utility's compliance with the new rules, and may assess penalties of up to $25,000 per day per violation. The MDPSC convened a working group of utilities, regulators, and other interested stakeholders to address the topics of the proposed rules. A draft of the rules was filed, along with the report of the working group, on October 27, 2011. Hearings to consider the rules and comments occurred over four days between December 8 and 15, 2011, after which revised rules were sent for legislative review. The proposed rules were published in the Maryland Register on February 24, 2012, and a deadline of March 26, 2012, was set for the filing of further comments. A further hearing is required before the rules could become final. Separately, on July 7, 2011, the MDPSC adopted draft rules requiring monitoring and inspections for contact voltage. The draft rules were published in September, 2011. After a further hearing in October, 2011, the final rules were re-published and became effective on November 28, 2011.

NEW JERSEY

On September 8, 2011, the Division of Rate Counsel filed a Petition with the NJBPU asserting that it has reason to believe that JCP&L is earning an unreasonable return on its New Jersey jurisdictional rate base. The Division of Rate Counsel requests that the NJBPU order JCP&L to file a base rate case petition so that the NJBPU may determine whether JCP&L's current rates for electric service are just and reasonable. JCP&L filed an answer to the Petition on September 28, 2011, stating, inter alia, that the Division of Rate Counsel analysis upon which it premises its Petition contains errors and inaccuracies, that JCP&L's achieved return on equity is currently within a reasonable range, and that there is no reason for the NJBPU to require JCP&L to file a base rate case at this time. On November 30, 2011, the NJBPU ordered that the matter be assigned to the NJBPU President to act as presiding officer to set and modify the schedule for this matter as appropriate, decide upon motions, and otherwise control the conduct of this case, without the need for full Board approval. The matter is pending and a schedule for further proceedings has not yet been established.

On September 22, 2011, the NJBPU ordered that JCP&L hire a Special Reliability Master, subject to NJBPU approval, to evaluate JCP&L's design, operating, maintenance and performance standards as they pertain to the Morristown, New Jersey underground electric distribution system, and make recommendations to JCP&L and the NJBPU on the appropriate courses of action necessary to ensure adequate reliability and safety in the Morristown underground network. On October 12, 2011, the Special Reliability Master was selected and on January 31, 2012, the project report was submitted to the Company and NJBPU Staff. On February 10, 2012, the NJBPU accepted the report and directed the Staff to present recommendations on March 12, 2012, on actions required by JCP&L to ensure the safe, reliable operation of the Morristown network.

Pursuant to a formal Notice issued by the NJBPU on September 14, 2011, public hearings were held on September 26 and 27, 2011, to solicit public comments regarding the state of preparedness and responsiveness of the local electric distribution companies prior to, during and after Hurricane Irene. By subsequent Notice issued September 28, 2011, additional hearings were held in October 2011. Additionally, the NJBPU accepted written comments through October 31, 2011 related to this inquiry. On December 4, 2011, the NJBPU Division of Reliability and Security issued a Request for Qualifications soliciting bid proposals from qualified consulting firms to provide expertise in the review and evaluation of New Jersey's electric distribution companies' preparation and restoration to Hurricane Irene and the October 2011 snowstorm. Responsive bids were submitted on January 20, 2012, and the report of selected bidder is to be submitted to the NJPBU 120 days from the date the contract is awarded. On December 14, 2011, the NJBPU Staff filed a report of its preliminary findings and recommendations with respect to the electric utility companies' planning and response to Hurricane Irene and the October 2011 snowstorm. The NJBPU has not indicated what additional action, if any, may be taken as a result of information obtained through this process.

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; 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, 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 in 2012. The PUCO issued an Opinion and Order generally approving the Ohio Companies' three-year plan, and the Ohio 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. Moreover, because the PUCO indicated, when approving the 2009 benchmark request, that it would modify the Ohio 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 May 19, 2011, the PUCO granted the request to reduce the 2010 energy efficiency and peak demand reductions to the level achieved in 2010 for OE, while finding that the motion was moot for CEI and TE. On June 2, 2011, the Ohio Companies filed an application for rehearing to clarify the decision related to CEI and TE. On July 27, 2011, the PUCO denied that application for rehearing, but clarified that CEI and TE could apply for an amendment in the future for the 2010 benchmarks should it be necessary to do so. Failure to comply with the benchmarks or to obtain such an amendment may subject the Ohio Companies to an assessment of a penalty by the PUCO. In addition to approving the programs included in the plan, with only minor modifications, the PUCO authorized the Ohio 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 by the Ohio Companies, Ohio Energy Group and Nucor Steel Marion, Inc. 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 September 7, 2011, the PUCO denied those applications for rehearing. The PUCO also included a new standard for compliance with the statutory energy efficiency benchmarks by requiring electric distribution companies to offer “all available cost effective energy efficiency opportunities” regardless of their level of compliance with the benchmarks as set forth in the statute. On October 7, 2011, the Ohio Companies, the Industrial Energy Users - Ohio, and the Ohio Energy Group filed applications for rehearing, arguing that the PUCO'S new standard is unlawful. The Ohio Companies also asked the PUCO to withdraw its amendment of CEI's and TE's 2010 energy efficiency benchmarks. The PUCO did not rule on the Applications for Rehearing within thirty days, thus denying them by operation of law. On December 30, 2011, the Ohio Companies filed a notice of appeal with the Supreme Court of Ohio, challenging the PUCO's new standard. No procedural schedule has been established.

Additionally, under SB221, electric utilities and electric service companies are required to serve part of their load in 2011 from renewable energy resources equivalent to 1.00% of the average of the KWH they served in 2008-2010; in 2012 from renewable energy resources equivalent to 1.50% of the average of the KWH they served in 2009-2011; and in 2013 from renewable energy resources equivalent to 2.00% of the average of the KWH they served in 2010-2012. 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 SRECs 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. 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. On August 3, 2011, the PUCO granted the Ohio Companies' force majeure request for 2010 and increased their 2011 benchmark by the amount of SRECs generated in Ohio that the Ohio Companies were short in 2010. On September 2, 2011, the Environmental Law and Policy Center and Nucor Steel Marion, Inc. filed applications for rehearing. The Ohio Companies filed their response on September 12, 2011. These applications for rehearing were denied by the PUCO on September 20, 2011, but as part of its Entry on Rehearing the PUCO opened a new docket to review the Ohio Companies' alternative energy recovery rider. Separately, one party has filed a request that the PUCO audit the cost of the Ohio Companies' compliance with the alternative energy requirements and the Ohio Companies' compliance with Ohio law. The PUCO selected auditors to perform a financial and a management audit, and final audit reports are to be filed with the PUCO by May 15, 2012. In August 2011, the Ohio Companies conducted two RFP processes to obtain RECs to meet the statutory benchmarks for 2011 and beyond.

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 customers 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 are continuing 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 the U.S. District Court for the Eastern District of Pennsylvania, which was subsequently amended. The PPUC filed a Motion to Dismiss Met-Ed's and Penelec's Amended Complaint on September 15, 2011. Met-Ed and Penelec filed a Responsive brief in Opposition to the PPUC's Motion to Dismiss on October 11, 2011. 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 each of May 2008, 2009 and 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 DSP 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, (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 provides for potentially significant financial penalties to be assessed upon utilities that fail to achieve the required reductions in consumption and peak demand. Act 129 also required utilities to file a SMIP with the PPUC.

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 became 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 ALJ. On December 15, 2011, the ALJ recommended that the amended plans be approved as proposed, and on January 12, 2012, the Commission approved the plans.
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 September 2010, WP filed an amended EE&C Plan that is less reliant on smart meter deployment,

which the PPUC approved in January 2011.
On August 9, 2011, WP filed a petition to approve its Second Amended EE&C Plan. The proposed Second Revised Plan includes measures and a new program and implementation strategies consistent with the successful EE&C programs of Met-Ed, Penelec and Penn that are designed to enable WP to achieve the post-2011 Act 129 EE&C requirements. On January 6, 2012, a Joint Petition for Settlement of all issues was filed by the parties to the proceeding.

The Pennsylvania Companies submitted a preliminary report on July 15, 2011, and a final report on November 15, 2011, in which they reported on their compliance with statutory May 31, 2011, energy efficiency benchmarks. Met-Ed, Penelec and Penn achieved the 2011 benchmarks; however WP has been unable to provide final results because several customers are still accumulating necessary documentation for projects that may qualify for inclusion in the final results. Preliminary numbers indicate that WP did not achieve its 2011 benchmark and it is not known at this time whether WP will be subject to a fine for failure to achieve the benchmark. WP is unable to predict the outcome of this matter or estimate any possible loss or range of loss.

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 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.
Following additional proceedings, 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. A Joint Stipulation with the OSBA was also filed on March 9, 2011. The PPUC approved the Amended Joint Petition for Full Settlement 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 accounting method utilized by Met-Ed and Penelec. On January 30, 2012, the Commission entered a final order approving Met-Ed's and Penelec's accounting methodology whereby NUG over-collection revenue may be used to reduce non-NUG stranded costs, even if a cumulative NUG stranded cost balance exists.

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 concerning retail markets in Pennsylvania. Met-Ed, Penelec, Penn Power and WP 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. A technical conference was held on August 10, 2011, and a second en banc was held on November 10, 2011, to discuss intermediate steps that can be taken to promote the development of a competitive market. Teleconferences are scheduled through March 2012, with another en banc hearing to be held on March 21, 2012, to explore the future of default service in Pennsylvania following the expiration of the upcoming default service plans on May 31, 2015. Following the issuance of a Tentative Order and comments filed by numerous parties, the Commission entered a final order on December 16, 2011, providing recommendations for components to be included in upcoming default service plans. An intermediate work plan was also presented on December 16, 2011, by Tentative Order, on which initial comments were submitted by Met-Ed, Penelec, Penn and WP on January 17, 2012. FES also submitted comments. Reply comments were submitted on February 1, 2012. It is expected that a final order implementing the intermediate work plan and a long range plan will be presented by the PPUC, both in March 2012.

The PPUC issued a Proposed Rulemaking Order on August 25, 2011, which proposed a number of substantial modifications to the current Code of Conduct regulations that were promulgated to provide competitive safeguards to the competitive retail electric market in Pennsylvania. The proposed changes include, but are not limited to: an EGS may not have the same or substantially similar name as the EDC or its corporate parent; EDCs and EGSs would not be permitted to share office space and would need to occupy different buildings; EDCs and affiliated EGSs could not share employees or services, except certain corporate support, emergency, or tariff services (the definition of "corporate support services" excludes items such as information systems, electronic data interchange, strategic management and planning, regulatory services, legal services, or commodities that have been included in regulated rates at less than market value); and an EGS must enter into a trademark agreement with the EDC before using its trademark or service mark. The Proposed Rulemaking Order, which was published on February 11, 2012, calls for comments to be submitted by March 27, 2012. If implemented these rules could require a significant change in the way FES, Met-Ed, Penelec, Penn and WP do business in Pennsylvania, and could possibly have an adverse impact on their results of operations and financial condition.

In November 2011, Met-Ed, Penelec, Penn and WP filed a Joint Petition for Approval of their Default Service Plan for the period June 1, 2013 through May 31, 2015. The Pennsylvania Companies' direct case was submitted in its entirety on December 20, 2011. Evidentiary hearings are scheduled for April 11-13, 2012, and a final order must be entered by the PPUC by August 17, 2012.

WEST VIRGINIA

In 2009, the West Virginia Legislature enacted the AREPA, 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 10% by 2015, 15% by 2020, and 25% by 2025.

In November 2010, the WVPSC issued 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 was issued by the WVPSC in September 2011, which conditionally approved MP's and PE's compliance plan, contingent on the outcome of the resource credits case discussed below.

Additionally, in January 2011, MP and PE filed an application with the WVPSC seeking to certify three facilities as Qualified Energy Resource Facilities. The application was approved and the three facilities are capable of generating renewable credits which will assist the companies in meeting their combined requirements under the AREPA. An annual update filing is due on March 31, 2012. 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 West Virginia. 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. A hearing was held at the WVPSC on August 25 and 26, 2011. On November 22, 2011, the WVPSC issued an order granting ownership of all RECs produced by the facilities to MP. On December 22, 2011, the WVPSC order was appealed, and the order was stayed pending the outcome of the appeal. MP's brief was filed on February 13, 2012. Should MP be unsuccessful in the appeal, it will have to procure the requisite RECs to comply with AREPA from other sources. MP expects to recover such costs from customers.

In September 2011, MP and PE filed with the WVPSC to recover costs associated with fuel and purchased power (the ENEC) in the amount of $32 million which represents an approximate 3% overall increase in such costs over the past two years, primarily attributable to rising coal prices. The requested increase was partially offset by $2.5 million of synergy savings directly resulting from the merger of FirstEnergy and AE, which closed in February 2011. Under a cost recovery clause established by the WVPSC in 2007, MP and PE customer bills are adjusted periodically to reflect upward or downward changes in the cost of fuel and purchased power. The utilities' most recent request to recover costs for fuel and purchased power was in September 2009. MP and PE entered into a Settlement Agreement related to this matter. The WVPSC issued an order on December 30, 2011, approving the settlement agreement. The approved settlement resulted in an increase of $19.6 million, instead of the requested $32 million, with additional costs to be recovered over time with a carrying charge.

FERC MATTERS

PJM Transmission Rate

In April 2007, FERC issued 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, 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 and higher voltage facilities on a load ratio share basis and, based on this finding, remanded the rate design issue to FERC.

In an order dated January 21, 2010, FERC set the matter for a "paper hearing" and requested 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 load serving entities 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. Other utilities and state commissions supported continued socialization of these costs on a load ratio share basis. This matter is awaiting action by FERC. FirstEnergy cannot predict the outcome of this matter or estimate the possible loss or range of loss.

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 TOs (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 analysis as part of FERC's evaluation of ATSI's proposed transmission rates. Finally, and also on June 30, 2011, the MISO and the MISO TOs filed a competing compliance filing - one that would require ATSI to pay certain charges related to construction and operation of transmission projects within the MISO even though FERC ruled that ATSI cannot pass these costs on to ATSI's customers. ATSI on the one hand, and the MISO and MISO TOs on the other, have submitted subsequent filings - each of which is intended to refute the other's claims. ATSI's compliance filing and request for rehearing, as well as the pleadings that reflect the dispute between ATSI and the MISO/MISO TOs, are currently pending before FERC.

From late April 2011 through June 2011, FERC issued other orders that address ATSI's move into PJM. Also, 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 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. Despite being presented with the issue by FirstEnergy and the MISO, the FERC did not address clearly the question of 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 requested 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. On October 21, 2011, FERC issued its order on rehearing, but that order did not address FirstEnergy's argument directly. FERC ruled instead that if ATSI was subject to MVP charges then ATSI owed these charges upon exit of the MISO. On October 31, 2011, FESC filed a Petition of Review for the FERC's December 2010 order and October 21, 2011 order on rehearing of that order with the U.S. Court of Appeals for the D.C. Circuit. Other parties also filed appeals of those orders and, in November, 2011, the cases were consolidated for briefing and disposition in the U.S. Court of Appeals for the Seventh Circuit. On January 27, 2012, the court ordered the FERC to file a proposed briefing format and schedule on or before March 20, 2012.

On August 3, 2011, FirstEnergy filed a complaint with FERC based on the FERC's December 2010 order. In the complaint, FirstEnergy argued that ATSI perfected the legal and financial requirements necessary to exit MISO before any MVP responsibilities could attach and asked FERC to rule that MISO cannot charge ATSI for MVP costs. On September 2, 2011, MISO, its TOs and other parties, filed responsive pleadings. On September 19, 2011, ATSI filed an answer. On December 29, 2011, the MISO and the MISO TOs filed a new “Schedule 39” to the MISO's tariff. Schedule 39 purports to establish a process whereby the MISO would bill TOs for MVP costs that, according to the MISO, attached to the utility prior to such TOs withdrawal from the MISO. On January 19, 2012, FirstEnergy filed a protest to the MISO's new Schedule 39 tariff.

On February 27, 2012, FERC issued an order (February 2012 Order) dismissing ATSI's August 3, 2011 complaint. In the February 2012 Order, FERC accepted the MISO's Schedule 39 tariff, subject to hearings and potential refund of MVP charges to ATSI. The basis for any subsequent hearing is whether the Schedule 39 tariff was in effect at the time that ATSI exited the MISO. FirstEnergy is evaluating the February 2012 Order and will determine the next steps.

FirstEnergy cannot predict the outcome of these proceedings or estimate the possible loss or range of loss.

FirstEnergy Companies' PJM FTR Contract Underfunding Complaint

On December 28, 2011, FES and AE Supply filed a complaint with FERC against PJM challenging the ongoing underfunding of FTR contracts, which exist to hedge against transmission congestion in the day-ahead markets. The underfunding is a result of PJM's practice of using the funds that are intended to pay the holders of FTR contracts to pay instead for congestion costs that occur in the real time markets. Underfunding of the FTR contracts resulted in losses of approximately $35 million to FES and AE Supply in the 2010-2011 Delivery Year. To date, losses for the 2011-2012 Delivery Year are estimated to be approximately $6 million.

On January 13, 2012, PJM filed comments that describe changes to the PJM tariff that, if adopted, should remedy the underfunding issue. Many parties also filed comments supporting FES' and AE Supply's position. Other parties, generally representatives of end-use customers who will have to pay the charges, filed in opposition to the complaint. The matter is currently pending before FERC. FirstEnergy cannot predict the outcome of this matter or estimate the possible loss or range of loss.

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 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. On June 3, 2011, the California parties requested rehearing of the May 4, 2011 order. The request for rehearing remains pending.

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. That request for rehearing also remains pending. FirstEnergy cannot predict the outcome of either of the above matters or estimate the possible loss or range of loss.

PATH Transmission 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 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 ROE 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% ROE incentive adder and a 0.5% ROE adder for RTO participation. These adders will be applied to the base ROE determined as a result of the hearing. The PATH Companies, Joint Intervenors, Joint Consumer Advocates and FERC staff have agreed to a four year moratorium. A settlement was reached, which reflects a base ROE of 10.4% (plus authorized adders) effective January 1, 2011. Accordingly, the revised ROE was reflected in a revised Projected Transmission Revenue Requirement for 2011 with true-up occurring in 2013. The FirstEnergy portion of the refund for March 1, 2008, through December 31, 2010, is approximately $2 million (inclusive of interest). The refund amount was computed using a base ROE of 10.8% plus authorized adders. On October 7, 2011, PATH and six intervenors submitted to FERC an unopposed settlement agreement. Contemporaneous with this submission, PATH and the six intervenors filed with the Chief ALJ of FERC a joint motion for interim approval and authorization to implement the refund on an interim basis pending issuance of a FERC order acting on the settlement agreement. On October 12, 2011, the motion for interim approval and authorization to implement the refund was granted by the Chief ALJ. On February 16, 2012, FERC approved the settlement agreement and dismissed as moot, in light of its approval of the settlement, PATH's pending request for rehearing of the November 19, 2010 order.

Yards Creek

The Yards Creek Pumped Storage Project is a 400 MW hydroelectric project located in Warren County, New Jersey. JCP&L owns an undivided 50% interest in the project, and operates the project. PSEG Fossil, LLC, a subsidiary of Public Service Enterprise Group, owns the remaining interest in the plant. The project was constructed in the early 1960s, and became operational in 1965. Authorization to operate the project is by a license issued by the FERC. The existing license expires on February 28, 2013.

In February 2011, JCP&L and PSEG filed a joint application with FERC to renew the license for an additional forty years. The companies are pursuing relicensure through FERC's ILP. Under the ILP, FERC will assess the license applications, issue draft and final Environmental Assessments/Environmental Impact Studies (as required by NEPA), and provide opportunities for intervention and protests by affected third parties. FERC may hold hearings during the two-year ILP licensure period. FirstEnergy expects FERC to issue the new license within the remaining portion of the two-year ILP period. To the extent, however, that the license proceedings extend beyond the February 28, 2013 expiration date for the current license, the current license will be extended yearly as necessary to permit FERC to issue the new license.

Seneca

The Seneca 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 PAD in the license docket.

On November 30, 2010, the Seneca Nation filed its notice of intent to relicense and PADs 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.

On September 12, 2011, FirstEnergy and the Seneca Nation each filed “Revised Study Plan” documents. These documents describe the parties' respective proposals for the scope of the environmental studies that should be performed as part of the relicensing process. On October 11, 2011, FERC Staff issued a letter order that addressed the Revised Study Plans. In the order, FERC Staff approved FirstEnergy's Revised Study Plan, subject to a finding that the Project is located on “aboriginal lands” of the Seneca Nation. Based on this finding, FERC Staff directed FirstEnergy to consult with the Seneca Nation and other parties about the data set, methodology, and modeling of the hydrological impacts of project operations. FirstEnergy is performing the work necessary to develop a study proposal from which to conduct such consultations. The study process will extend through approximately November of 2013.

FirstEnergy cannot predict the outcome of this matter or estimate the possible loss or range of loss.

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 or non-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 air emissions from the coal-fired Bruce Mansfield Plant. 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 complaints.

The states of New Jersey and Connecticut filed CAA citizen suits in 2007 alleging NSR violations at the coal-fired 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 or estimate the possible loss or range of loss.

In January 2009, the EPA issued a NOV to GenOn Energy, Inc. alleging NSR violations at the coal-fired Portland Generation Station based on “modifications” dating back to 1986. 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 and Penelec are unable to predict the outcome of this matter or estimate the possible loss or range of loss.

In each of May and September 2010, New Jersey submitted interstate pollution transport petitions seeking to reduce Portland Generating Station air emissions under section 126 of the CAA. Based on the September 2010 petition, the EPA has finalized emissions limits and compliance schedules to reduce SO_2 air emissions by approximately 81% at the Portland Station by January 6, 2015. New Jersey's May 2010 petition is still under consideration by the EPA.

In June 2008, the EPA issued a Notice and Finding of Violation to 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, NYSEG 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, NYSEG, and various current owners of Homer City, including EME Homer City Generation L.P. and affiliated companies, including Edison International. 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. 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.” In October 2011, the Court dismissed all of the claims with prejudice of the U.S. and the Commonwealth of Pennsylvania and the States of New Jersey and New York and all of the claims of the private parties, without prejudice to re-file state law claims in state court, against all of the defendants, including Penelec.In December 2011, the U.S., the Commonwealth of Pennsylvania and the States of New Jersey and New York all filed notices appealing to the Third Circuit Court of Appeals. Penelec believes the claims are without merit and intends to defend itself against the allegations made in these complaints, but, at this time, is unable to predict the outcome of this matter or estimate the loss or possible range of loss. Mission is seeking indemnification from NYSEG and Penelec, the co-owners of Homer City prior to its sale in 1999. On February 13, 2012, the Sierra Club notified the current owner and operator of Homer City, Homer City OL1-OL8 LLC and EME Homer City Generation L.P., that it intends to file a CAA citizen suit regarding its Title V permit and SO_2 emissions from the Homer City Plant.

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 during maintenance outages dating back to 1990 triggered the pre-construction permitting requirements under the PSD and NNSR programs. FGCO also 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 provisions of the CAA. Later in 2009, FGCO also received another information request regarding emission projections for the 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 or estimate the possible loss or range of loss.

In August 2000, AE received an information request pursuant to section 114(a) of the CAA 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 NSR provisions under the CAA, which can require the installation of additional air emission control equipment when a 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 or estimate the possible loss or range of loss.

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 generation units: 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 coal-fired 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 and we are unable to predict the outcome or estimate the possible loss or range of loss.

In September 2007, Allegheny 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 coal-fired Hatfield's Ferry and Armstrong plants in Pennsylvania and the coal-fired Fort Martin and Willow Island plants in West Virginia.

FirstEnergy intends to vigorously defend against the CAA matters described above but cannot predict their outcomes or estimate the possible loss or range of loss.

State Air Quality Compliance

In early 2006, Maryland passed the Healthy Air Act, which imposes state-wide emission caps on SO_2 and NOx, 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 tenth state to join the RGGI. The Healthy Air Act provides a conditional exemption for the R. Paul Smith coal-fired plant for NOx, SO_2 and mercury, based on a 2006 PJM declaration that the plant is vital to reliability in the Baltimore/Washington DC metropolitan area. Pursuant to the legislation, the MDE passed alternate NOx 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% which began 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. Fourteen RGGI auctions have been held through the end of calendar year 2011. 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. On June 30, 2011, PJM notified MDE that termination of operation at R. Paul Smith would adversely impact the reliability of electrical service in the PJM region absent transmission system upgrades. On January 26, 2012, FirstEnergy announced that R. Paul Smith is among nine coal-fired plants it intends to retire by September 1, 2012, subject to review of reliability impacts by PJM. FirstEnergy is unable to predict the outcome of this matter or estimate the possible loss or range of loss.

In January 2010, the WVDEP issued a NOV for opacity emissions at the Pleasants coal-fired plant. In August 2011, FirstEnergy and WVDEP resolved the NOV through a Consent Order requiring installation of a reagent injection system to reduce opacity by September 2012.

National Ambient Air Quality Standards

The EPA's CAIR requires reductions of NOx and SO_2 emissions in two phases (2009/2010 and 2015), ultimately capping SO_2 emissions in affected states to 2.5 million tons annually and NOx emissions to 1.3 million tons annually. In 2008, the U.S. Court of Appeals for the District of Columbia 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 CSAPR, to replace CAIR,requiring reductions of NOx and SO_2 emissions in two phases (2012 and 2014), ultimately capping SO_2 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. On February 21, 2012, the EPA revised certain CASPR state budgets (for Florida, Louisiana, Michigan, Mississippi, Nebraska, New Jersey, New York, Texas, and Wisconsin and new unit set-asides in Arkansas and Texas), certain generating unit allocations (for some units in Alabama, Indiana, Kansas, Kentucky, Ohio and Tennessee) for NOx and SO_2 emissions and delayed from 2012 to 2014 certain allowance penalties that could apply with respect to interstate trading of NOx and SO_2 emission allowances. On December 30, 2011, CSAPR was stayed by the U.S. Court of Appeals for the District of Columbia Circuit pending a decision on legal challenges raised in appeals filed by various stakeholders and scheduled to be argued before the Court on April 13, 2012. The Court ordered EPA to continue administration of CAIR until the Court resolves the CSAPR appeals. Depending on the outcome of these proceedings and how any final rules are ultimately implemented, FGCO's and AE Supply's future cost of compliance may be substantial and changes to FirstEnergy's operations may result.

During 2011, FirstEnergy recorded pre-tax impairment charges of approximately $6 million ($1 million for FES and $5 million for AE Supply) for NOx emission allowances that were expected to be obsolete after 2011 and approximately $21 million ($18 million for FES and $3 million for AE Supply) for excess SO_2 emission allowances in inventory that it expects will not be consumed in the future.

Hazardous Air Pollutant Emissions

On December 21, 2011, the EPA finalized the MATS to establish emission standards for mercury, hydrochloric acid and various metals for electric generating units. The MATS establishes emission limits for mercury, PM, and HCL for all existing and new coal-fired electric generating units effective in April 2015 and allows averaging of emissions from multiple units located at a single plant. Under the CAA, state permitting authorities can grant an additional compliance year through April 2016, as needed, including instances when necessary to maintain reliability where electric generating units are being closed. In addition, an EPA enforcement policy document contemplates up to an additional year to achieve compliance, through April 2017, under certain circumstances for reliability critical units.

On January 26, 2012 and February 8, 2012, FGCO, MP and AE Supply announced the retirement by September 1, 2012 (subject to a reliability review by PJM) of nine coal-fired power plants (Albright, Armstrong, Ashtabula, Bay Shore except for generating unit 1, Eastlake, Lake Shore, R. Paul Smith, Rivesville and Willow Island) with a total capacity of 3,349 megawatts (generating, on average, approximately ten percent of the electricity produced by the companies over the past three years) due to MATS and other environmental regulations. In addition, MP will make a filing with the WVPSC to provide them with information regarding the retirement of its plants. Depending on how the MATS are ultimately implemented, FirstEnergy's future cost of compliance with MATS may be substantial and other changes to FirstEnergy's operations may result.

On February 24, 2012, PJM notified FirstEnergy of its preliminary analysis of the reliability impacts that may result from closure of the older competitive coal-fired generating units. PJM's preliminary analysis indicated that there would be significant reliability concerns that will need to be addressed. FirstEnergy intends to continue to actively engage in discussions with PJM regarding this notification, including the possible continued operation of certain plants.

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. 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 and report GHG emissions commencing in 2010. 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 of CO_2 equivalents effective January 2, 2011, for existing facilities under the CAA's PSD program.

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 three years with a goal of increasing to $100 billion by 2020; and establishes the “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.A December 2011 U.N. Climate Change Conference in Durban, Africa, established a negotiating process to develop a new post-2020 climate change protocol, called the “Durban Platform for Enhanced Action”. This negotiating process contemplates developed countries, as well as developing countries such as China, India, Brazil, and South Africa, to undertake legally binding commitments post-2020. In addition, certain countries agreed to extend the Kyoto Protocol for a second commitment period, commencing in 2013 and expiring in 2018 or 2020.

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 but failed to answer the question of the extent to which actions for damages based on GHG emissions may remain viable. The Court remanded to the Second Circuit the issue of whether the CAA preempted state common law nuisance actions.

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 CWA 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 CWA 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 CWA 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 CWA 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. 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 CWA 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. On August 5, 2011, EPA issued an information request pursuant to Sections 308 and 311 of the CWA for certain information pertaining to the oil spills and spill prevention measures at FirstEnergy facilities. FirstEnergy responded on October 10, 2011. On February 1, 2012, FirstEnergy executed a tolling agreement with the EPA extending the statute of limitations to July 31, 2012. FGCO does not anticipate any losses resulting from this matter to be material.

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 impoundments at the Albright Station seeking unspecified civil penalties and injunctive relief. The MP filed an answer on July 11, 2011, and a motion to stay the proceedings on July 13, 2011. On January 3, 2012, the Court denied MP's motion to dismiss or stay the CWA citizen suit but without prejudice to re-filing in the future. 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 a60-Day Notice of Intent required prior to filing a citizen suit under the CWA for alleged failure to obtain a permit to construct the fly ash impoundments at the Albright Plant.

FirstEnergy intends to vigorously defend against the CWA matters described above but, except as indicated above, cannot predict their outcomes or estimate the possible loss or range of loss.

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 coal-fired Hatfield's Ferry 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 estimated costs in excess of $150 million in order to install technology to meet TDS and sulfate limits in the permit or negatively affect its ability to operate the scrubbers as designed. 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. A hearing on the parties' appeals was 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, and has rescheduled a hearing, if necessary, for July 2012. If these settlement discussions are successful, AE Supply anticipates that its obligations will not be material. AE Supply intends to vigorously pursue these issues, but cannot predict the outcome of these appeals or estimate the possible loss or range of loss.

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 CWA 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 the coal-fired Hatfield's Ferry and Mitchell Plants in Pennsylvania and the coal-fired Fort Martin Plant in West Virginia.

In October 2009, the WVDEP issued the water discharge permit for the Fort Martin Plant. Similar to the Hatfield's Ferry water discharge permit, 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 discharge 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 or estimate the possible loss or range of loss.

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 advance 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. Compliance with those regulations could have an adverse impact on FirstEnergy's results of operations and financial condition.

LBR CCB impoundment is expected to run out of disposal capacity for disposal of CCBs from the BMP between 2016 and 2018. BMP is pursuing several CCB disposal options.

Certain of our utilities 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 December 31, 2011, based on estimates of the total costs of cleanup, the Utility Registrants' proportionate responsibility for such costs and the financial ability of other unaffiliated entities to pay. Total liabilities of approximately $106 million (JCP&L - $70 million, TE - $1 million, CEI - $1 million, FGCO - $1 million and FE - $33 million) have been accrued through December 31, 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 an additional expense of $29 million during the second quarter of 2011; $30 million had previously been reserved prior to 2011. FirstEnergy determined that it is reasonably possible that it or its subsidiaries could be found potentially responsible for additional amounts or additional sites, but the possible losses or range of losses cannot be determined or reasonably estimated at this time.

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. In November 2010, the Supreme Court issued an order denying Plaintiffs' motion for leave to appeal. The Court's order effectively ends the attempt to certify the class, and leaves only 9 plaintiffs to pursue their respective individual claims. The matter was referred back to the lower court, which set a trial date for February 13, 2012, for the remaining individual plaintiffs. Plaintiffs have accepted an immaterial amount in final settlement of all matters and the settlement documentation is being finalized for execution by all parties.

Nuclear Plant Matters

Under NRC regulations, FirstEnergy must ensure that adequate funds will be available to decommission its nuclear facilities. As of December 31, 2011, FirstEnergy had approximately $2 billion invested in external trusts to be used for the decommissioning and environmental remediation of Davis-Besse, Beaver Valley, Perry and TMI-2. 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. 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. By

letter dated December 29, 2011, FENOC informed the NRC staff that it had increased the parental guarantee to $95 million.
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's failure to begin accepting spent nuclear fuel on January 31, 1998. DOE was required to begin 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. In January 2012, the applicable FirstEnergy affiliates reached a $48 million settlement of these claims.

In August 2010, FENOC submitted an application to the NRC for renewal of the Davis-Besse operating license for an additional twenty years, until 2037. By an order dated April 26, 2011, a NRC 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 from the order granting a hearing on the Davis-Besse license renewal application. On January 10, 2012, intervenors petitioned the ASLB for a new contention on the cracking of the Davis-Besse shield building discussed below.

On October 1, 2011, Davis-Besse was safely shut down for a scheduled outage to install a new reactor vessel head and complete other maintenance activities. The new reactor head, which replaced a head installed in 2002, enhances safety and reliability, and features control rod nozzles made of material less susceptible to cracking. On October 10, 2011, following opening of the building for installation of the new reactor head, a sub-surface hairline crack was identified in one of the exterior architectural elements on the shield building. These elements serve as architectural features and do not have structural significance. During investigation of the crack at the shield building opening, concrete samples and electronic testing found similar sub-surface hairline cracks in most of the building's architectural elements. FENOC's investigation also identified other indications. Included among them were sub-surface hairline cracks in the upper portion of the shield building (above elevation 780') and in the vicinity of the main steam line penetrations. A team of industry-recognized structural concrete experts and Davis-Besse engineers has determined these conditions do not affect the facility's structural integrity or safety.

On December 2, 2011, the NRC issued a CAL which concluded that FENOC provided "reasonable assurance that the shield building remains capable of performing its safety functions." The CAL imposed a number of commitments from FENOC including, submitting a root cause evaluation and corrective actions to the NRC by February 28, 2012, and further evaluations of the shield building. On February 27, 2012, FENOC sent the root cause evaluation to the NRC. Finally, the CAL also stated that the NRC was still evaluating whether the current condition of the shield building conforms to the plant's licensing basis. On December 6, 2011, the Davis-Besse plant returned to service.

By letter dated August 25, 2011, the NRC made a final significance determination (white) associated with a violation that occurred during the retraction of a source range monitor from the Perry reactor vessel. The NRC also placed Perry in the degraded cornerstone column (Column 3) of the NRC's Action Matrix governing the oversight of commercial nuclear reactors. As a result, the NRC staff will conduct several supplemental inspections, culminating in an inspection using Inspection Procedure 95002 to determine if the root cause and contributing causes of risk significant performance issues are understood, the extent of condition has been identified, whether safety culture contributed to the performance issues, and if FENOC's corrective actions are sufficient to address the causes and prevent recurrence.

In light of the impacts of the earthquake and tsunami on the reactors in Fukushima, Japan, the NRC conducted inspections of emergency equipment at U.S. reactors. The NRC also established a Near-Term Task Force to review its processes and regulations in light of the incident, and, on July 12, 2011, the Task Force issued its report of recommendations for regulatory changes. On October 18, 2011, the NRC approved the Staff recommendations, and directed the Staff to implement its near-term recommendations without delay. Ultimately, the adoption of the Staff recommendations on near-term actions is likely to result in additional costs to implement plant modifications and upgrades required by the regulatory process over the next several years, which costs are likely to be material.

On February 16, 2012, the NRC issued a request for information to the licensed operators of 11 nuclear power plants, including Beaver Valley Power Station Units 1 and 2, with respect to the modeling of fuel performance as it relates to "thermal conductivity degradation," which is the potential in older fuel for reduced capacity to transfer heat that could potentially change its performance during various accident scenarios, including loss of coolant accidents. The request for information indicated that this phenomenon has not been accounted for adequately in performance models for the fuel developed by the fuel manufacturer. The NRC is requesting that FENOC provide an analysis to demonstrate that the NRC regulations are being met. Absent that demonstration, the request indicates that the NRC may consider imposing restrictions on reactor operating limits until the issue is satisfactorily resolved.

ICG Litigation

On December 28, 2006, AE Supply and MP filed a complaint in the Court of Common Pleas of Allegheny County, Pennsylvania against ICG, Anker WV, and 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. On August 25, 2011, the Allegheny County Court denied all Motions for Post-Trial relief and the May 2, 2011 verdict became final. On August 26, 2011, ICG posted bond and filed a Notice of Appeal. Briefing on the Appeal is concluded with oral argument expected in May or June of 2012. AE Supply and MP intend to vigorously pursue this matter through appeal.

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. On October 21, 2011, the Court of Appeals rendered its decision affirming the dismissal of the Complaint by the Court of Common Pleas on all counts except for one relating to an allegation of fraud. The Companies timely filed a notice of appeal on December 5, 2011 with the Supreme Court of Ohio challenging this one aspect of the Court of Appeals opinion. The Supreme Court of Ohio has not yet acted on the appeal.

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 under Note 15, Regulatory Matters.

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. In cases where FirstEnergy determines that it is not probable, but reasonably possible that it has a material obligation, it discloses such obligations and the possible loss or range of loss and if such estimate can be made. If it were ultimately determined that FirstEnergy or its subsidiaries have legal liability or are otherwise made subject to liability based on any of the matters referenced above, it could have a material adverse effect on FirstEnergy's or its subsidiaries' financial condition, results of operations and cash flows.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

FirstEnergy prepares consolidated financial statements in accordance with GAAP. Application of these principles often requires a high degree of judgment, estimates and assumptions that affect financial results. FirstEnergy's accounting policies require significant judgment regarding estimates and assumptions underling the amounts included in the financial statements. Additional information regarding the application of accounting policies are included in the Combined Notes to the Consolidated Financial Statements.

Revenue Recognition

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

Regulatory Accounting

FirstEnergy’s regulated distribution and regulated independent transmission segments are subject to regulations that sets the prices (rates) the Utilities, ATSI, TrAIL and PATH are permitted to charge customers based on costs that the regulatory agencies determine are permitted to recover. At times, regulators permit the future recovery through rates of costs that would be currently charged to expense by an unregulated company. This ratemaking process results in the recording of regulatory assets and liabilities based on anticipated future cash inflows and outflows. FirstEnergy regularly reviews these assets to assess their ultimate recoverability within the approved regulatory guidelines. Impairment risk associated with these assets relates to potentially adverse legislative, judicial or regulatory actions in the future.

Pensions and OPEB Accounting

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.

As described in Note 1, Organization, Basis of Presentation and Significant Accounting Policies, FirstEnergy elected to change its method of recognizing actuarial gains and losses for its defined benefit pension plans and OPEB plans effective in 2011. Previously, FirstEnergy recognized the net actuarial gains and losses as a component of AOCI and amortized the gains and losses into income over the remaining service life of affected employees within the related plans, to the extent such gains and losses were outside a corridor of the greater of 10% of the market-related value of plan assets or 10% of the plans' projected benefit obligation.

FirstEnergy has elected to immediately recognize the change in the fair value of plan assets and net actuarial gains and losses annually in the fourth quarter of each fiscal year and whenever a plan is determined to qualify for a remeasurement. The remaining components of pension and OPEB expense, primarily service, interest, assumed return on assets and prior service costs, will be recorded on a quarterly basis.

FirstEnergy's funding policy is based on actuarial computations using the projected unit credit method. During 2011, FirstEnergy made pre-tax contributions to its qualified pension plans of $372 million. FirstEnergy made an additional $600 million pre-tax contribution to its qualified pension plan on January 5, 2012. The underfunded status of FirstEnergy’s qualified and non-qualified pension and OPEB plans as of December 31, 2011 was $2.6 billion.

As a result of the merger with AE in 2011, FirstEnergy assumed certain pension and OPEB plans. FirstEnergy measured the funded status of the Allegheny pension plans and OPEB plans 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 OPEB plans 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 OPEB plans.

In selecting an assumed discount rate, FirstEnergy considers currently available rates of return on high-quality fixed income investments expected to be available during the period to maturity of the pension and OPEB obligations. The assumed discount rates for pensions were 5.00%, 5.50% and 6.00% as of December 31, 2011, 2010 and 2009, respectively. The assumed discount rates for OPEB were 4.75%, 5.00% and 5.75% as of December 31, 2011, 2010 and 2009, respectively.

FirstEnergy’s assumed rate of return on pension plan assets considers historical market returns and economic forecasts for the types of investments held by the pension trusts. In 2011, FirstEnergy’s qualified pensions and OPEB plan assets earned $387 million or 6.05% compared to amounts earned of $492 million, or 10.1% in 2010. The qualified pension and OPEB costs in 2011 and 2010 were computed using an assumed 8.25% and 8.50% rate of return, respectively, on plan assets which generated $486 million and $397 million of expected returns on plan assets, respectively. The expected return of pensions and OPEB assets is based on the trusts’ asset allocation targets and the historical performance of risk-based and fixed income securities. The gains or losses generated as a result of the difference between expected and actual returns on plan assets will increase or decrease future net periodic pension and OPEB cost as the difference is recognized annually in the fourth quarter of each fiscal year.

Based on discounts rates of 5.00% for pension, 4.75% for OPEB and an estimated return on assets of 7.75%, FirstEnergy expects its 2012 pre-tax net periodic postemployment benefit credits (including amounts capitalized) to be approximately $117 million (excluding any actuarial mark-to-market adjustments that would be recognized in 2012).

The following table reflects the portion of pensions and OPEB costs that were charged to expense in the three years ended December 31, 2011.

Postemployment Benefits Expense (Credits)	2011	2010	2009
	(In millions)		
Pensions	$555	$247	$377
OPEB	(112)	(126)	(57)
Total	$443	$121	$320

Health care cost trends continue to increase and will affect future OPEB costs. The 2011 composite health care trend rate assumptions were approximately 7.5-8.5%, compared to 8.0-9.0% in 2010, gradually decreasing to 5% in later years. In determining FirstEnergy’s trend rate assumptions, included are the specific provisions of FirstEnergy’s health care plans, the demographics and utilization rates of plan participants, actual cost increases experienced in FirstEnergy’s health care plans, and projections of future medical trend rates. The effect on the pension and OPEB costs from changes in key assumptions are as follows:

Increase in Net Periodic Benefit Costs from Adverse Changes in Key Assumptions

Assumption	Adverse Change	Pensions	OPEB	Total
			(In millions)	
Discount rate	Decrease by 0.25%	$236	$23	$259
Long-term return on assets	Decrease by 0.25%	$16	$1	$17
Health care trend rate	Increase by 1.0%	N/A	$27	$27

Emission Allowances

FirstEnergy holds emission allowances for SO_2 and NOx in order to comply with programs implemented by the EPA designed to regulate emissions of SO_2 and NOx produced by power plants. Emission allowances are either granted by the EPA at zero cost or are purchased at fair value as needed to meet emission requirements. Emission allowances are not purchased with the intent of resale. Emission allowances eligible to be used in the current year are recorded in materials and supplies inventory at their weighted average cost. Emission allowances eligible for use in future years are recorded as other investments. FirstEnergy recognizes emission allowance costs as fuel expense during the periods that emissions are produced by generating facilities. Emission allowances that are not needed to meet emission requirements may be sold and are reported as a reduction to other operating expenses. Obsolete or excess emission allowances follow FirstEnergy's inventory practice that requires the emission allowances to be recorded at the lower of weighted average cost or market value. See Note 11, Impairment of Long-Lived Assets for further information on impairments of emission allowances.

Long-Lived Assets

FirstEnergy reviews long-lived assets, including regulatory assets, for impairment whenever events or changes in circumstances indicate that the carrying amount of such an asset may not be recoverable. The recoverability of the long-lived asset is measured by comparing the long-lived asset's 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 future cash flows of the long-lived asset, 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. Impairments of long-lived assets recognized for the year ended December 31, 2011, are described further in Note 11, Impairment of Long-Lived Assets.

Asset Retirement Obligations

FirstEnergy recognizes an ARO for the future decommissioning of its nuclear power plants and future remediation of other environmental liabilities associated with all of its long-lived assets. The ARO liability represents an estimate of the fair value of FirstEnergy's current obligation related to nuclear decommissioning and the retirement or remediation of environmental liabilities of other assets. A fair value measurement inherently involves uncertainty in the amount and timing of settlement of the liability. FirstEnergy uses an expected cash flow approach to measure the fair value of the nuclear decommissioning and environmental remediation ARO. This approach applies probability weighting to discounted future cash flow scenarios that reflect a range of possible outcomes. The scenarios consider settlement of the ARO at the expiration of the nuclear power plant's current license, settlement based on an extended license term and expected remediation dates. The fair value of an ARO is recognized in the period in which it is incurred. The associated asset retirement costs are capitalized as part of the carrying value of the long-lived asset and are depreciated over the life of the related asset.

Income Taxes

FirstEnergy records income taxes in accordance with the liability method of accounting. Deferred income taxes reflect the net tax effect of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts recognized for tax purposes. Investment tax credits, which were deferred when utilized, are being amortized over the recovery period of the related property. Deferred income tax liabilities related to temporary tax and accounting basis differences and tax credit carryforward items are recognized at the statutory income tax rates in effect when the liabilities are expected to be paid. Deferred tax assets are recognized based on income tax rates expected to be in effect when they are settled.

FirstEnergy accounts for uncertainty in income taxes recognized in its financial statements. We account for uncertain income tax positions using a benefit recognition model with a two-step approach, a more-likely-than-not recognition criterion and a measurement attribute that measures the position as the largest amount of tax benefit that is greater than 50% likely of being ultimately realized upon ultimate settlement. If it is not more likely than not that the benefit will be sustained on its technical merits, no benefit will be recorded. Uncertain tax positions that relate only to timing of when an item is included on a tax return are considered to have met the recognition threshold. The Company 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.

Goodwill

In a business combination, the excess of the purchase price over the estimated fair values of the assets acquired and liabilities assumed is recognized as goodwill. Goodwill is evaluated for impairment at least annually and more frequently if indicators of impairment arise. In accordance with accounting standards, if the fair value of a reporting unit is less than its carrying value (including goodwill), the goodwill is tested for impairment. Impairment is indicated and a loss is recognized if the implied fair value of a reporting unit's goodwill is less than the carrying value of its goodwill.

NEW ACCOUNTING PRONOUNCEMENTS

See Note 1, Organization, Basis of Presentation and Significant Accounting Policies 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 to wholesale and retail customers, and through its principal subsidiaries, FGCO and NGC, owns or leases, operates and maintains FirstEnergy's fossil and hydroelectric generation facilities (excluding the Allegheny facilities), and owns, through its subsidiary, NGC, FirstEnergy's nuclear generation facilities, respectively. FENOC, a wholly owned subsidiary of FirstEnergy, operates and maintains the nuclear generating facilities. FES purchases the entire output of the generation facilities owned by FGCO and NGC, 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, and pursuant to full output, cost-of-service PSAs.

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, Michigan, New Jersey and Maryland. 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 principally 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: Strategy and Outlook, Risks and Challenges, Capital Resources and Liquidity, Guarantees and Other Assurances, Off-Balance Sheet Arrangements, Regulatory Matters, Environmental Matters, Other Legal Proceedings, Critical Accounting Policies, Outlook and New Accounting Pronouncements.

Results of Operations

Net income decreased by $290 million in 2011 compared to 2010. The decrease was primarily due to higher operating expenses, an inventory reserve adjustment and the effect of mark-to-market adjustments, partially offset by lower non-core asset impairment charges.

Revenues

Total revenues decreased $351 million, or 6%, in 2011 compared to 2010, primarily due to reduced POLR and structured sales, partially offset by growth in direct and governmental aggregation sales.

The net decrease in total revenues resulted from the following sources:

Revenues by Type of Service	2011	2010	Increase (Decrease)	
	(In millions)			
Direct and Governmental Aggregation	$3,785	$2,493	$1,292	
POLR and Structured Sales	944	2,589	(1,645	)
Wholesale	457	397	60	
Transmission	108	77	31	
RECs	67	74	(7	)
Sale of OVEC participation interest	—	85	(85	)
Other	116	113	3	
Total Revenues	$5,477	$5,828	$(351	)

MWH Sales by Type of Service	2011	2010	Increase (Decrease)	
	(In thousands)			
Direct	46,187	28,499	62.1	%
Governmental Aggregation	17,722	12,796	38.5	%
POLR and Structured Sales	15,340	50,358	(69.5	)%
Wholesale	2,916	5,391	(45.9	)%

Total Sales	82,165	97,044	(15.3)%

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The increase in direct and governmental aggregation revenues of $1.3 billion resulted from the acquisition of new residential, commercial and industrial customers, as well as new governmental aggregation contracts with communities in Ohio and Illinois that provide generation to approximately 1.8 million residential and small commercial customers at the end of 2011 compared to approximately 1.5 million customers at the end of 2010. Increases in direct sales volume were partially offset by lower unit prices.
The decrease in POLR and structured sales revenues of $1.6 billion was due to lower sales volumes to Met-Ed, Penelec and the Ohio Companies, partially offset by increased sales to non-affiliates and higher unit prices to the Pennsylvania Companies. The decline in POLR sales reflects our focus on more profitable sales channels.
Wholesale revenues increased $60 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, partially offset by increased short-term transactions in PJM. In addition, capacity revenues earned by units that moved to PJM from MISO were partially offset by losses on financially settled sales contracts.
The following tables summarize the price and volume factors contributing to changes in revenues from generation sales:

Source of Change in Direct and Governmental Aggregation	Increase(Decrease) (In millions)
Direct Sales:	
Effect of increase in sales volumes	$1,034
Change in prices	(75)
	959
Governmental Aggregation:	
Effect of increase in sales volumes	319
Change in prices	14
	333
Increase in Direct and Government Aggregation Revenues	$1,292

Source of Change in POLR and Structured Revenues	Increase (Decrease) (In millions)
Effect of decrease in sales volumes	$(1,800)
Change in prices	155
	$(1,645)

Source of Change in Wholesale Revenues	Increase (Decrease) (In millions)
Effect of decrease in sales volumes	$(182)
Change in prices	242
	$60

Transmission revenues increased $31 million due primarily to higher congestion revenue. Revenues derived from the sale of RECs decreased $7 million in 2011 compared to 2010.
Operating Expenses
Total operating expenses decreased by $34 million in 2011 compared with the 2010.

The following table summarizes the factors contributing to the changes in fuel and purchased power costs in 2011 compared with 2010:

Source of Change in Fuel and Purchased Power	Increase (Decrease) (In millions)
Fossil Fuel:	
Change due to increased unit costs	$26
Change due to volume consumed	(107)
	(81)
Nuclear Fuel:	
Change due to increased unit costs	28
Change due to volume consumed	(6)
	22
Non-affiliated Purchased Power:	
Change due to increased unit costs	416
Change due to volume purchased	(623)
	(207)
Affiliated Purchased Power:	
Change due to decreased unit costs	(84)
Change due to volume purchased	(45)
	(129)
Net Decrease in Fuel and Purchased Power Costs	$(395)

Total fuel costs decreased by $59 million in 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 costs 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 $217 million in 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 that FES no longer has the requirement to serve. Affiliated purchased power costs decreased by $119 million in 2011, compared to the same period of 2010, due to lower unit costs and decreased volumes purchased.

Other operating expenses increased by $400 million in 2011 compared to the same period of 2010 due to the following:

- Transmission expenses increased by $249 million due primarily to increases in congestion, network and line loss expenses.
- Nuclear operating costs increased $53 million primarily due to Perry and Beaver Valley Unit 2 refueling outages in 2011. While Davis-Besse had a refueling outage in 2010 and an outage in 2011 to replace the reactor vessel head, the work performed on both outages was largely capital-related.
- Fossil operating costs increased $36 million due primarily to higher labor, contractor and material costs resulting from an increase in planned and unplanned outages, which were partially offset by reduced losses from the sale of excess coal.
- A $54 million provision for excess and obsolete material related to revised inventory practices adopted in connection with the Allegheny merger.
- Pensions and OPEB mark-to-market adjustment charges increased $64 million as a result of higher net actuarial losses.

Impairment charges on long-lived assets decreased by $94 million compared to 2010. The 2011 charges were due to the pending shutdown of four coal-fired generating units owned by FGCO; charges in 2010 related to operational changes at certain smaller coal-fired units.

General taxes increased by $30 million due to an increase in revenue-related taxes.

Provision for depreciation increased by $29 million due to the AQC projects being placed in service at the end of 2010.

Other Expense

Total other expense increased by $41 million in 2011, compared to 2010, primarily due to a $57 million decrease in capitalized interest associated with the completion of the Sammis AQC project in 2010, partially offset by lower interest expense ($5 million).

Market Risk Information

FES 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

FES is exposed to financial risks resulting from fluctuating interest rates and commodity prices, including prices for electricity, natural gas, coal and energy transmission. FirstEnergy's Risk Policy 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. FES uses a variety of derivative instruments for risk management purposes including forward contracts, options, futures contracts and swaps.

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, FES relies on model-based information. The model provides estimates of future regional prices for electricity and an estimate of related price volatility. FES uses these results to develop estimates of fair value for financial reporting purposes and for internal management decision making (see Note 9, Fair Value Measurements of the Combined Notes to the Consolidated Financial Statements).

Sources of information for the valuation of commodity derivative contract assets and liabilities as of December 31, 2011, are summarized by year in the following table:

Source of Information- Fair Value by Contract Year	2012	2013	2014	2015	2016	Thereafter	Total
	(In millions)						
Prices actively quoted[1]	$—	$—	$—	$—	$—	$—	$—
Other external sources[2]	(15)	11	20	8	—	—	24
Prices based on models	(6)	—	—	—	(2)	(8)	(16)
Total	$(21)	$11	$20	$8	$(2)	$(8)	$8

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

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

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

Interest Rate Risk

FES’ exposure to fluctuations in market interest rates is reduced since a significant portion of its debt has fixed interest rates. The table below presents principal amounts and related weighted average interest rates by year of maturity for FES’ investment portfolio and debt obligations.

Comparison of Carrying Value to Fair Value

Year of Maturity	2012	2013	2014	2015	2016	There-after	Total	Fair Value
	(In millions)							
Assets:								
Investments Other Than Cash and Cash Equivalents:								
Fixed Income						$1,025	$1,025	$1,025
Average interest rate						6.5 %	6.5 %	
Liabilities:								
Long-term Debt:								

Fixed rate	$68	$75	$99	$450	$26	$2,445	$3,163	$3,419
Average interest rate	9.0 %	9.0 %	7.3 %	5.1 %	7.7 %	5.1 %	5.4 %	
Variable rate						$512	$512	$512
Average interest rate						0.1 %	0.1 %	

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Equity Price Risk

NDT funds have been established to satisfy NGC's nuclear decommissioning obligations. Included in FES's NDT are fixed income, equities and short-term investments carried at market values of approximately $1,025 million, $124 million and $132 million, respectively, as of December 31, 2011, excluding ($58) million of net receivables, payables and accrued income. A hypothetical 10% decrease in prices quoted by stock exchanges would result in a $12 million reduction in fair value as of December 31, 2011. NGC recognized in earnings the unrealized losses on available-for-sale securities held in their NDT as OTTI. A decline in the value of FES's NDT or a significant escalation in estimated decommissioning costs could result in additional funding requirements.

Credit Risk

Credit risk is defined as the risk that a counterparty to a transaction will be unable to fulfill its contractual obligations. FES evaluates the credit standing of a prospective counterparty based on the prospective counterparty's financial condition. FES may impose specified collateral requirements and use standardized agreements that facilitate the netting of cash flows. FES monitors the financial conditions of existing counterparties on an ongoing basis. An independent risk management group oversees credit risk.

Wholesale Credit Risk

FES measures wholesale credit risk as the replacement cost for derivatives in power, natural gas, coal and emission allowances, adjusted for amounts owed to or due from counterparties for settled transactions. The replacement cost of open positions represents unrealized gains, net of any unrealized losses, where FES has a legally enforceable right of setoff. FES monitors and manages the credit risk of wholesale marketing, risk management and energy transacting operation through credit policies and procedures, which include an established credit approval process, daily monitoring of counterparty credit limits, the use of credit mitigation measures such as margin, collateral and the use of master netting agreements. FES 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).

Retail Credit Risk

FES is exposed to retail credit risk through competitive electricity activities, which serve residential, commercial and industrial companies. Retail credit risk results when customers default on contractual obligations or fail to pay for service rendered. This risk represents the loss that may be incurred due to the nonpayment of customer accounts receivable balances, as well as the loss from the resale of energy previously committed to serve customers.

Retail credit risk is managed through established credit approval policies, monitoring customer exposures and the use of credit mitigation measures such as deposits in the form of letters of credit, cash or prepayment arrangements.

Retail credit quality is dependent on the economy and the ability of customers to manage through unfavorable economic cycles and other market changes. If the business environment were to be negatively affected by changes in economic or other market conditions, FES's retail credit risk may be adversely impacted.

OHIO EDISON COMPANY
MANAGEMENT'S NARRATIVE
ANALYSIS OF RESULTS OF OPERATIONS

OE is a wholly owned electric utility subsidiary of FirstEnergy. OE engages in the distribution and sale of electric energy to communities in a 7,000 square mile area of central and northeastern Ohio and, through its wholly owned subsidiary, Penn, 1,100 square miles in western Pennsylvania. OE and Penn conduct business in portions of Ohio and Pennsylvania, providing regulated electric distribution services and procurement of generation services for those franchise customers electing to retain them as their power supplier. The areas served by OE and Penn have populations of approximately 2.3 million and 0.4 million, respectively.

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: Strategy and Outlook, Risks and Challenges, Capital Resources and Liquidity, Contractual Obligations, Off-Balance Sheet Arrangements, Regulatory Matters, Environmental Matters, Other Legal Proceedings, Critical Accounting Policies and New Accounting Standards and Interpretations.

Results of Operations

Net income decreased by $27 million in 2011 compared to 2010. The decrease primarily resulted from lower revenues and higher other operating expenses, partially offset by lower purchased power costs.

Revenues

Revenues decreased by $203 million, or 11%, in 2011 compared with 2010 due to lower retail generation revenues, partially offset by higher distribution and wholesale generation revenues.

Distribution revenues increased by $69 million in 2011, compared to 2010, due to increased MWH deliveries and higher average prices in all customer classes. The higher MWH deliveries in the residential class were driven primarily by increased load growth partially offset by lower weather-related usage. The increase in distribution deliveries to commercial and industrial customers was primarily due to recovering economic conditions in OE's and Penn's service territories. Higher average prices in all customer classes were principally due to the recovery of deferred distribution costs.

Changes in distribution MWH deliveries and revenues in 2011 compared to 2010, are summarized in the following tables:

Distribution MWH Deliveries	Increase	
Residential	0.3	%
Commercial	0.7	%
Industrial	5.4	%
Increase in Distribution Deliveries	2.0	%

Distribution Revenues	Increase (In millions)
Residential	$26
Commercial	17
Industrial	26
Increase in Distribution Revenues	$69

Retail generation revenues decreased by $277 million primarily due to a decrease in MWH sales from increased customer shopping and lower average prices in all customer classes. Retail generation obligations are attributable to non-shopping customers and are satisfied by generation procured through full-requirements auctions. OE and Penn defer the difference between retail generation revenues and purchased power costs, resulting in no material effect to current period earnings. Lower MWH sales were primarily the result of increased customer shopping in 2011. The increases in shopping by residential, commercial and industrial customers were 18%, 11% and 7%, respectively, in 2011 compared with 2010.

Decreases in retail generation MWH sales and revenues in 2011 compared to 2010 are summarized in the following tables:

Retail Generation MWH Sales	Decrease	
Residential	(28.8	)%
Commercial	(34.0	)%
Industrial	(22.6	)%
Decrease in Retail Generation Sales	(28.3	)%

Retail Generation Revenues	Decrease	
	(In millions)	
Residential	$(166	)
Commercial	(74	)
Industrial	(37	)
Decrease in Retail Generation Revenues	$(277	)

Wholesale generation revenues increased by $12 million in 2011 compared to 2010 due to higher revenues from sales to NGC from OE's leasehold interests in Perry Unit 1 and Beaver Valley Unit 2.

Operating Expenses

Total operating expenses decreased by $175 million in 2011 compared to 2010. The following table presents changes from the prior year by expense category:

Operating Expenses - Changes	Increase (Decrease)	
	(In millions)	
Purchased power costs	$(279	)
Other operating expenses	109	
Pensions and OPEB mark-to-market adjustment	19	
Provision for depreciation	2	
Amortization of regulatory assets, net	(33	)
General taxes	7	
Net Decrease in Operating Expenses	$(175	)

Purchased power costs decreased in 2011 compared to 2010 due to lower MWH purchases resulting from reduced generation sales requirements coupled with lower unit costs. The increase in other operating expenses in 2011 compared to the same period of 2010 was principally due to expenses associated with nuclear refueling outages at OE's leased Perry Unit 1 and Beaver Valley Unit 2 that were absent in 2010. Decreased pensions and OPEB mark-to-market adjustment charges are the result of lower net actuarial losses in 2011 compared to 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.

Interest Rate Risk

OE's exposure to fluctuations in market interest rates is reduced since all of its debt has fixed interest rates. The table below presents principal amounts and related weighted average interest rates by year of maturity for OE's investment portfolio and debt obligations.

Comparison of Carrying Value to Fair Value

Year of Maturity	2012	2013	2014	2015	2016	There-after	Total	Fair Value
	(In millions)							
Assets:								
Investments Other Than Cash and Cash Equivalents:								
Fixed Income	$31	$36	$42	$37	$13	$138	$297	$318
Average interest rate	8.7 %	8.8 %	8.8 %	8.9 %	8.9 %	4.4 %	6.8 %	
Liabilities:								
Long-term Debt:								
Fixed rate				$150	$250	$757	$1,157	$1,434
Average interest rate				5.5 %	6.4 %	7.3 %	6.9 %	

Equity Price Risk

NDT funds have been established to satisfy nuclear decommissioning obligations. Included in OE’s NDT are fixed income and short-term investments carried at market values of approximately $134 million and $1 million, respectively, as of December 31, 2011, excluding $2 million of net receivables, payables and accrued income. OE recognizes in earnings the unrealized losses on available-for-sale securities held in its NDT as OTTI. A decline in the value of OE's NDT or a significant escalation in estimated decommissioning costs could result in additional funding requirements. During 2011, approximately $4 million was contributed to OE's NDT to comply with requirements under certain sale-leaseback transactions in which OE continues as a lessee.

Credit Risk

Credit risk is defined as the risk that a counterparty to a transaction will be unable to fulfill its contractual obligations. OE evaluates the credit standing of a prospective counterparty based on the prospective counterparty's financial condition. OE may impose specified collateral requirements and use standardized agreements that facilitate the netting of cash flows. OE monitors the financial conditions of existing counterparties on an ongoing basis. An independent risk management group oversees credit risk.

THE CLEVELAND ELECTRIC ILLUMINATING COMPANY
MANAGEMENT'S NARRATIVE
ANALYSIS OF RESULTS OF OPERATIONS

CEI is a wholly owned, electric utility subsidiary of FirstEnergy. CEI provides regulated electric distribution services in an area of 1,600 square miles in northeastern Ohio. The area it serves has a population of approximately 1.7 million. CEI also procures generation services for those customers electing to retain them 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: Strategy and Outlook, Risks and Challenges, Capital Resources and Liquidity, Contractual Obligations, Off-Balance Sheet Arrangements, Regulatory Matters, Environmental Matters, Other Legal Proceedings, Critical Accounting Policies and New Accounting Standards and Interpretations.

On January 25, 2012, CEI filed a Form 15 with the SEC to deregister its securities and suspend its obligation to file periodic reports under the Securities Exchange Act of 1934, as amended, except that the registrant has filed this Annual Report on Form 10-K for the year ended December 31, 2011. This Annual Report on Form 10-K will be the last filing made by CEI with the SEC under the Exchange Act.

Results of Operations

Earnings available to parent decreased by $5 million in 2011 compared to 2010. The decrease in earnings was primarily due to decreased revenues, partially offset by lower purchased power costs and amortization of regulatory assets.

Revenues

Revenues decreased $345 million, or 28%, in 2011 compared to 2010 due to lower retail generation and distribution revenues.

Distribution revenues decreased $78 million in 2011 compared to 2010 due to lower average unit prices in all customer classes offset by increased MWH deliveries to the industrial sector. The lower average unit prices were the result of the absence of transition charges in 2011. Lower residential and commercial deliveries resulted from decreased weather-related usage in 2011. In the industrial sector, MWH deliveries increased primarily as a result of recovering economic conditions in CEI's service territory.

Changes in distribution MWH deliveries and revenues in 2011 compared to 2010 are summarized in the following tables:

Distribution MWH Deliveries	Increase (Decrease)	
Residential	(0.3	)%
Commercial	(0.4	)%
Industrial	1.4	%
Net Increase in Distribution Deliveries	0.2	%

Distribution Revenues	Decrease (In millions)	
Residential	$(12	)
Commercial	(7	)
Industrial	(59	)
Decrease in Distribution Revenues	$(78	)

Retail generation revenues decreased $265 million in 2011 as compared to 2010 primarily due to lower MWH sales to all customer classes that resulted from increased customer shopping and lower average unit prices for the commercial and residential customer classes. Retail generation obligations are attributable to non-shopping customers and are satisfied by generation 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. Lower MWH sales were the result of increased shopping by residential, commercial and industrial customers of 15%, 8% and 36%, respectively, in 2011 compared to 2010. Lower average unit prices in the residential customer class were primarily due to the lower auction price in 2011.

Changes in retail generation sales and revenues in 2011 compared to 2010 are summarized in the following tables:

Retail Generation MWH Sales	Decrease	
Residential	(38.8	)%
Commercial	(37.6	)%
Industrial	(71.3	)%
Decrease in Retail Generation Sales	(52.2	)%

Retail Generation Revenues	Decrease (In millions)	
Residential	$(88	)
Commercial	(77	)
Industrial	(100	)
Decrease in Retail Generation Revenues	$(265	)

Operating Expenses

Total operating expenses decreased $336 million in 2011 compared to 2010. The following table presents changes from the prior year by expense category:

Operating Expenses - Changes	Increase (Decrease) (In millions)	
Purchased power costs	$(254	)
Other operating costs	15	
Pensions and OPEB mark-to-market adjustment	8	
Provision for depreciation	1	
Amortization of regulatory assets, net	(117	)
General taxes	11	
Net Decrease in Operating Expenses	$(336	)

Purchased power costs decreased in 2011 primarily due to lower MWH purchases resulting from reduced sales requirements as a result of increased customer shopping. Other operating expenses increased due to 2011 inventory valuation adjustments. Increased pensions and OPEB mark-to-market adjustment changes were due to higher net actuarial losses in 2011 as compared to 2010. Amortization of regulatory assets decreased primarily due to the completion of transition cost recovery at the end of 2010 and higher deferred purchased power costs 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 due to increased property taxes as compared to 2010.

Interest Rate Risk

CEI's exposure to fluctuations in market interest rates is reduced since all of its debt has fixed interest rates. The table below presents principal amounts and related weighted average interest rates by year of maturity for CEI’s investment portfolio and debt obligations.

Comparison of Carrying Value to Fair Value

Year of Maturity	2012	2013	2014	2015	2016	There-after	Total	Fair Value
	(In millions)							
Assets:								
Investments Other Than Cash and Cash Equivalents:								
Fixed Income	$66	$75	$80	$50	$16		$287	$315
Average interest rate	7.7 %	7.7 %	7.7 %	7.7 %	8.0 %		7.7 %	
Liabilities:								
Long-term Debt:								
Fixed rate		$325	$26	$24	$6	$1,450	$1,831	$2,162
Average interest rate		5.8 %	7.7 %	7.7 %	7.7 %	6.8 %	6.7 %	

Credit Risk

Credit risk is defined as the risk that a counterparty to a transaction will be unable to fulfill its contractual obligations. CEI evaluates the credit standing of a prospective counterparty based on the prospective counterparty's financial condition. CEI may impose specified collateral requirements and use standardized agreements that facilitate the netting of cash flows. CEI monitors the financial conditions of existing counterparties on an ongoing basis. An independent risk management group oversees credit risk.

THE TOLEDO EDISON COMPANY
MANAGEMENT’S NARRATIVE
ANALYSIS OF RESULTS OF OPERATIONS

TE is a wholly owned electric utility subsidiary of FirstEnergy. TE provides regulated electric distribution services in an area of 2,300 square miles in northwestern Ohio. The area it serves has a population of approximately 0.7 million. TE also provides generation services to those customers electing to retain them 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: Strategy and Outlook, Risks and Challenges, Capital Resources and Liquidity, Contractual Obligations, Off-Balance Sheet Arrangements, Regulatory Matters, Environmental Matters, Other Legal Proceedings, Critical Accounting Policies and New Accounting Standards and Interpretations.

On January 25, 2012, TE filed a Form 15 with the SEC to deregister its securities and suspend its obligation to file periodic reports under the Securities Exchange Act of 1934, as amended, except that the registrant has filed this Annual Report on Form 10-K for the year ended December 31, 2011. This Annual Report on Form 10-K will be the last filing made by TE with the SEC under the Exchange Act.

Results of Operations

Earnings available to parent decreased by $2 million in 2011 compared to 2010. The decrease was primarily from lower revenues and higher other operating expenses, partially offset by lower purchased power costs from affiliates.

Revenues

Revenues decreased $40 million, or 8%, in 2011 compared to 2010, primarily due to lower retail generation sales, partially offset by an increase in distribution revenues.

Distribution revenues increased $28 million in 2011 compared to 2010, primarily due to higher MWH deliveries to residential and industrial customers and higher unit prices to all customer classes related to increased energy efficiency rider rates, partially offset by lower MWH deliveries to commercial customers. Higher MWH deliveries to residential customers reflected increased load growth slightly offset by lower weather-related usage that also drove lower deliveries to commercial customers. In the industrial sector, MWH deliveries increased primarily as a result of recovering economic conditions in TE's service territory.

Changes in distribution MWH deliveries and revenues in 2011 compared to 2010 are summarized in the following tables:

Distribution MWH Deliveries	Increase (Decrease)	
Residential	0.3	%
Commercial	(1.9	)%
Industrial	2.4	%
Net Increase in Distribution Deliveries	1.0	%

Distribution Revenues	Increase (In millions)
Residential	$11
Commercial	9
Industrial	8
Increase in Distribution Revenues	$28

Retail generation revenues decreased $79 million in 2011 compared to 2010, primarily due to lower MWH sales from increased customer shopping and lower unit prices to all customer classes. The increases in shopping for residential, commercial and industrial customers were 13%, 9%, and 4%, respectively, in 2011 compared with 2010. Retail generation obligations are attributable to non-shopping customers and are satisfied by generation 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.

Decreases in retail generation MWH sales and revenues in 2011 compared to 2010 are summarized in the following tables:

Retail Generation MWH Sales	Decrease
Residential	(27.9)%
Commercial	(39.7)%
Industrial	(10.1)%
Decrease in Retail Generation Sales	(20.5)%

Retail Generation Revenues	Decrease (In millions)
Residential	$(28)
Commercial	(21)
Industrial	(30)
Decrease in Retail Generation Revenues	$(79)

Wholesale revenues increased $12 million in 2011 compared to 2010, primarily due to higher revenues from sales to NGC from TE’s leasehold interest in Beaver Valley Unit 2.

Operating Expenses

Total operating expenses decreased $37 million in 2011 compared to 2010. The following table presents changes from the prior year by expense category:

Operating Expenses - Changes	Increase (Decrease) (In millions)
Purchased power costs	$(76)
Other operating expenses	31
Pensions and OPEB mark-to-market adjustment	6
General taxes	2
Net Decrease in Operating Expenses	$(37)

Purchased power costs decreased in 2011 compared to 2010, due to lower MWH purchases resulting from reduced generation sales requirements in 2011 coupled with lower unit costs. The increase in other operating costs in 2011 was primarily due to expenses associated with the 2011 nuclear 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. Increased pensions and OPEB mark-to-market adjustment charges were due to higher net actuarial losses in 2011 as compared to 2010.

Other Expense

Other expense decreased slightly in 2011 compared to 2010, due to a decrease in miscellaneous expense partially offset by lower investment income. The change in miscellaneous expense was due to decreased expenses associated with the accounts receivable securitization with Centerior Funding Corp., which was terminated in 2011 Investment income decreased principally due to lower NDT investment income.

Interest Rate Risk

TE's exposure to fluctuations in market interest rates is reduced since all of its debt has fixed interest rates. The table below presents principal amounts and related weighted average interest rates by year of maturity for TE’s investment portfolio and debt obligations.

Comparison of Carrying Value to Fair Value

Year of Maturity	2012	2013	2014	2015	2016	There-after	Total	Fair Value
	(In millions)							
Assets:								
Investments Other Than Cash and Cash Equivalents:								
Fixed Income		$25	$26	$24	$6	$53	$134	$145
Average interest rate		7.7 %	7.7 %	7.7 %	7.7 %	4.6 %	6.4 %	
Liabilities:								
Long-term Debt:								
Fixed rate						$600	$600	$741
Average interest rate						6.7 %	6.7 %	

Equity Price Risk

NDT funds have been established to satisfy nuclear decommissioning obligations. Included in TE’s NDT are fixed income, equities and short-term investments carried at market values of approximately $53 million, $27 million and $3 million, respectively, as of December 31, 2011. A hypothetical 10% decrease in prices quoted by stock exchanges would result in a $3 million reduction in fair value as of December 31, 2011. TE recognizes in earnings the unrealized losses on available-for-sale securities held in their NDT as OTTI. A decline in the value of TE’s NDT or a significant escalation in estimated decommissioning costs could result in additional funding requirements. During 2011, approximately $1 million was contributed to TE's NDT to comply with requirements under certain sale-leaseback transactions in which TE continues as a lessee.

Credit Risk

Credit risk is defined as the risk that a counterparty to a transaction will be unable to fulfill its contractual obligations. TE evaluates the credit standing of a prospective counterparty based on the prospective counterparty's financial condition. TE may impose specified collateral requirements and use standardized agreements that facilitate the netting of cash flows. TE monitors the financial conditions of existing counterparties on an ongoing basis. An independent risk management group oversees credit risk.

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 in 3,200 square miles of northern, western and east central New Jersey. The area it serves has a population of approximately 2.7 million. JCP&L also has an ownership interest in a hydroelectric generating facility. In addition, JCP&L also procures generation services for franchise customers electing to retain them as their power supplier. JCP&L procures electric supply to serve its BGS customers through a statewide auction process approved by the NJBPU.

For additional information with respect to JCP&L, please see the information contained in FirstEnergy's Management's Discussion and Analysis of Financial Condition and Results of Operations under the following subheadings, which information is incorporated by reference herein: Strategy and Outlook, Risks and Challenges, Capital Resources and Liquidity, Contractual Obligations, Regulatory Matters, Environmental Matters, Other Legal Proceedings, Critical Accounting Policies and New Accounting Standards and Interpretations.

Results of Operations

Net income decreased by $39 million in 2011 compared to 2010. The decrease was primarily due to lower revenues, partially offset by reductions in purchased power costs and amortization of regulatory assets.

Revenues

Revenues decreased by $532 million, or 18%, in 2011 compared to 2010. The decrease in revenues was due to lower distribution, retail generation and wholesale generation revenues, partially offset by an increase in other revenues.

Distribution revenues decreased by $187 million in 2011, compared to 2010, primarily due to an NJBPU-approved rate adjustment that became effective March 1, 2011 for all customer classes, and lower MWH deliveries. The lower MWH deliveries to residential customers were influenced by decreased weather-related usage in 2011. Lower distribution deliveries to commercial and industrial customers reflected the impact of economic conditions in JCP&L's service territory.

Decreases in distribution MWH deliveries and revenues in 2011 compared to 2010 are summarized in the following tables:

Distribution MWH Deliveries	Decrease	
Residential	(3.0	)%
Commercial	(2.9	)%
Industrial	(3.0	)%
Decrease in Distribution Deliveries	(2.9	)%

Distribution Revenues	Decrease (In millions)	
Residential	$(90	)
Commercial	(79	)
Industrial	(18	)
Decrease in Distribution Revenues	$(187	)

Retail generation revenues decreased by $301 million due to lower generation MWH sales in all customer classes primarily due to an increase in customer shopping. The increases in shopping for residential, commercial and industrial customers were 10%, 9% and 5%, respectively, in 2011 compared with 2010. Retail generation obligations are attributable to non-shopping customers and are satisfied by generation procured through full-requirements auctions. JCP&L defers the difference between retail generation revenues and purchased power costs, resulting in no material effect to earnings.

Decreases in retail generation MWH sales and revenues in 2011, compared to 2010, are summarized in the following tables:

Retail Generation MWH Sales	Decrease
Residential	(13.0)%
Commercial	(23.0)%
Industrial	(29.0)%
Decrease in Retail Generation Sales	(16.3)%

Retail Generation Revenues	Decrease (In millions)
Residential	$(181)
Commercial	(108)
Industrial	(12)
Decrease in Retail Generation Revenues	$(301)

Wholesale generation revenues decreased by $54 million in 2011, compared to 2010, due to a decrease in PJM spot market energy sales.

Other revenues increased by $10 million in 2011, compared to 2010, primarily due to increases in PJM network transmission revenues and transition bond revenues from increased rates.

Operating Expenses

Total operating expenses decreased by $461 million in 2011 compared to 2010. The following table presents changes from the prior year by expense category:

Operating Expenses - Changes	Increase (Decrease) (In millions)
Purchased power costs	$(354)
Other operating expenses	48
Pensions and OPEB mark-to-market adjustment	34
Provision for depreciation	22
Amortization of regulatory assets, net	(213)
General taxes	2
Net Decrease in Operating Expenses	$(461)

Purchased power costs decreased by $354 million in 2011 due to lower requirements from reduced retail generation sales. Other operating expenses increased by $48 million in 2011 principally from storm restoration maintenance costs. Increased pensions and OPEB mark-to-market adjustment changes were due to higher net actuarial losses in 2011 as compared to 2010. Amortization of regulatory assets, net, decreased by $213 million due to reduced cost recovery under the NJBPU-approved NUG tariffs that became effective March 1, 2011 and higher deferred storm restoration costs, partially offset by a charge for nonrecoverable NUG costs.

Market Risk Information

JCP&L 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

JCP&L is exposed to financial risks resulting from fluctuating interest rates and commodity prices, including prices for electricity, natural gas and energy transmission. FirstEnergy's Risk Policy 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. JCP&L uses a variety of derivative instruments for risk management purposes including forward contracts, options, futures contracts and swaps.

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, JCP&L relies on model-based information. The model provides estimates of future regional prices for electricity and an estimate of related price volatility. JCP&L uses these results to develop estimates of fair value for financial reporting purposes and for internal management decision making (see Note 9, Fair Value Measurements of the Combined Notes to the Consolidated Financial Statements). Sources of information for the valuation of commodity derivative contract assets and liabilities as of December 31, 2011, are summarized by year in the following table:

Source of Information-Fair Value by Contract Year	2012	2013	2014	2015	2016	Thereafter	Total
	(In millions)						
Prices actively quoted[1]	$—	$—	$—	$—	$—	$—	$—
Other external sources[2]	(52)	(43)	(36)	(14)	—	—	(145)
Prices based on models	—	—	—	—	1	1	2
Total[3]	$(52)	$(43)	$(36)	$(14)	$1	$1	$(143)

(1) Represents exchange traded New York Mercantile Exchange futures and options.
(2) Primarily represents contracts based on broker and IntercontinentalExchange quotes.
(3) Includes $(143) million in non-hedge commodity derivative contracts that are related to NUG contracts. NUG contracts are subject to regulatory accounting and do not materially impact earnings.

JCP&L performs sensitivity analyses to estimate its exposure to the market risk of its commodity positions. Based on derivative contracts held as of December 31, 2011, an adverse 10% change in commodity prices would not have a material effect on JCP&L's net income for the next 12 months.

Interest Rate Risk

JCP&L's exposure to fluctuations in market interest rates is reduced since all of its debt has fixed interest rates. The table below presents principal amounts and related weighted average interest rates by year of maturity for JCP&L's investment portfolio and debt obligations.

Comparison of Carrying Value to Fair Value

Year of Maturity	2012	2013	2014	2015	2016	There-after	Total	Fair Value
	(In millions)							
Assets:								
Investments Other Than Cash and Cash Equivalents:								
Fixed Income						$363	$363	$363
Average interest rate						5.2%	5.2%	
Liabilities:								
Long-term Debt:								
Fixed rate	$34	$36	$38	$41	$343	$1,285	$1,777	$2,080
Average interest rate	5.7%	5.7%	5.9%	6.0%	5.7%	6.2%	6.1%	

Equity Price Risk

NDT funds have been established to satisfy nuclear decommissioning obligations. Included in JCP&L's NDT are fixed income, equities and short-term investments carried at market values of approximately $147 million, $30 million and $14 million, respectively, as of December 31, 2011, excluding $2 million of net receivables, payables and accrued income. A hypothetical 10% decrease in prices quoted by stock exchanges would result in a $3 million reduction in fair value as of December 31, 2011. JCP&L's NDT is 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. A decline in the value of JCP&L's NDT or a significant escalation in estimated decommissioning costs could result in additional funding requirements. During 2011, approximately $1 million was contributed to JCP&L's NDT to comply with regulatory requirements.

Credit Risk

Credit risk is defined as the risk that a counterparty to a transaction will be unable to fulfill its contractual obligations. JCP&L evaluates the credit standing of a prospective counterparty based on the prospective counterparty's financial condition. JCP&L may impose specified collateral requirements and use standardized agreements that facilitate the netting of cash flows. JCP&L monitors the financial conditions of existing counterparties on an ongoing basis. An independent risk management group oversees credit risk.

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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 provides regulated electric transmission and distribution services in 3,300 square miles of eastern and south central Pennsylvania. The area it serves has a population of approximately 1.2 million. Met-Ed also procures generation service for those franchise customers who have elected to retain them as their power supplier. Met-Ed procures power under its 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 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: Strategy and Outlook, Risks and Challenges, Capital Resources and Liquidity, Contractual Obligations, Off-Balance Sheet Arrangements, Regulatory Matters, Environmental Matters, Other Legal Proceedings, Critical Accounting Policies and New Accounting Standards and Interpretations.

On January 25, 2012, Met-Ed filed a Form 15 with the SEC to deregister its securities and suspend its obligation to file periodic reports under the Securities Exchange Act of 1934, as amended, except that the registrant has filed this Annual Report on Form 10-K for the year ended December 31, 2011. This Annual Report on Form 10-K will be the last filing made by Met-Ed with the SEC under the Exchange Act.

Results of Operations

Net income increased by $8 million in 2011 compared to 2010. The increase was primarily due to decreased purchased power costs, other operating expenses and amortization of net regulatory assets partially offset by decreased revenues.

Revenues

Revenue decreased $606 million, or 33%, in 2011 compared to 2010, reflecting lower distribution, retail generation, wholesale generation and transmission revenues.

Distribution revenues decreased $336 million in 2011 compared to 2010, primarily due to lower rates resulting from the DSP that began in 2011 that eliminated the transmission component from the distribution rates. The lower MWH deliveries to residential and commercial customers were influenced by decreased weather-related usage in 2011. In the industrial sector, MWH deliveries increased primarily as a result of recovering economic conditions in Met-Ed's service territory.

Changes in distribution MWH deliveries and revenues in 2011 compared to 2010 are summarized in the following tables:

Distribution MWH Deliveries	Increase (Decrease)
Residential	(1.4)%
Commercial	(2.0)%
Industrial	2.2%
Net Decrease in Distribution Deliveries	(0.2)%

Distribution Revenues	Decrease (In millions)
Residential	$(133)
Commercial	(90)
Industrial	(113)
Decrease in Distribution Revenues	$(336)

In 2011, retail generation revenues decreased $52 million due to lower MWH sales to all customer classes resulting from increased customer shopping. 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 satisfied by generation 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.

Changes in retail generation MWH sales and revenues in 2011 compared to 2010 are summarized in the following tables:

Retail Generation MWH Sales	Decrease
Residential	(3.8)%
Commercial	(49.1)%
Industrial	(91.8)%
Net Decrease in Retail Generation Sales	(45.7)%

Retail Generation Revenues	Increase (Decrease) (In millions)
Residential	$166
Commercial	(24)
Industrial	(194)
Net Decrease in Retail Generation Revenues	$(52)

Wholesale revenues decreased $210 million in 2011 compared to 2010, primarily reflecting lower RPM revenues for Met-Ed in the PJM market.

Transmission revenues decreased $9 million in 2011 compared to 2010 primarily due to the termination of Met-Ed’s TSC rates effective January 1, 2011. Met-Ed deferred the difference between transmission revenues and transmission costs incurred, resulting in no material effect to earnings in the period.

Operating Expenses

Total operating expenses decreased $608 million in 2011 compared to 2010. The following table presents changes from the prior year by expense category:

Operating Expenses - Changes	Increase (Decrease) (In millions)
Purchased power costs	$(328)
Other operating costs	(230)
Pensions and OPEB mark-to-market adjustment	26
Provision for depreciation	5
Amortization of regulatory assets, net	(68)
General taxes	(13)
Net Decrease in Operating Expenses	$(608)

Purchased power costs decreased $328 million in 2011 compared to 2010 due to a decrease in MWH purchased to source generation sales requirements, partially offset by higher unit costs. Decreased power purchased from affiliates reflects the increase in customer shopping described above and the termination of Met-Ed's partial requirements PSA with FES at the end of 2010. Other operating costs decreased $230 million in 2011 compared to 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. Increased pensions and OPEB mark-to-market adjustment changes were due to higher net actuarial losses in 2011 as compared to 2010. The amortization of regulatory assets decreased $68 million in 2011 compared to 2010 primarily due to the termination of transmission and transition tariff riders at the end of 2010. General taxes decreased by $13 million in 2011 primarily due to lower gross receipts taxes.

Other Expense

Interest income decreased by $3 million in 2011 compared to 2010 primarily due to reduced CTC stranded asset balances.

Market Risk Information

Met-Ed 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

Met-Ed is exposed to financial risks resulting from fluctuating interest rates and commodity prices, including prices for electricity, natural gas and energy transmission. FirstEnergy's Risk Policy 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. Met-Ed uses a variety of derivative instruments for risk management purposes including forward contracts, options, futures contracts and swaps.

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, Met-Ed relies on model-based information. The model provides estimates of future regional prices for electricity and an estimate of related price volatility. Met-Ed uses these results to develop estimates of fair value for financial reporting purposes and for internal management decision making (see Note 9, Fair Value Measurements of the Combined Notes to the Consolidated Financial Statements).

Sources of information for the valuation of commodity derivative contract assets and liabilities as of December 31, 2011, are summarized by year in the following table:

Source of Information- Fair Value by Contract Year	2012	2013	2014	2015	2016	Thereafter	Total
	(In millions)						
Prices actively quoted[1]	$—	$—	$—	$—	$—	$—	$—
Other external sources[2]	(62)	(7)	(6)	(5)	—	—	(80)
Prices based on models	—	—	—	—	8	42	50
Total[3]	$(62)	$(7)	$(6)	$(5)	$8	$42	$(30)

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

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

(3) Includes $(30) million in non-hedge commodity derivative contracts that are related to NUG contracts. NUG contracts are subject to regulatory accounting and do not materially impact earnings.

Met-Ed performs sensitivity analyses to estimate its exposure to the market risk of its commodity positions. Based on derivative contracts held as of December 31, 2011, an adverse 10% change in commodity prices would not have a material effect on Met-Ed’s net income for the next 12 months.

Interest Rate Risk

Met-Ed’s exposure to fluctuations in market interest rates is reduced since a significant portion of its debt has fixed interest rates. The table below presents principal amounts and related weighted average interest rates by year of maturity for Met-Ed’s investment portfolio and debt obligations.

Comparison of Carrying Value to Fair Value

Year of Maturity	2012	2013	2014	2015	2016	There-after	Total	Fair Value
	(In millions)							
Assets:								
Investments Other Than Cash and Cash Equivalents:								
Fixed Income						$234	$234	$234
Average interest rate						3.3%	3.3%	
Liabilities:								
Long-term Debt:								
Fixed rate		$150	$250			$300	$700	$796
Average interest rate		5.0%	4.9%			7.7%	6.1%	
Variable rate						$29	$29	$29
Average interest rate						0.1%	0.1%	

Equity Price Risk

NDT funds have been established to satisfy nuclear decommissioning obligations. Included in Met-Ed’s NDT are fixed income, equities and short-term investments carried at market values of approximately $234 million, $51 million and $23 million, respectively, as of December 31, 2011, excluding $2 million of net receivables, payables and accrued income. A hypothetical 10% decrease in prices quoted by stock exchanges would result in a $5 million reduction in fair value as of December 31, 2011. Met-Ed's NDT is 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. A decline in the value of Met-Ed's NDT or a significant escalation in estimated decommissioning costs could result in additional funding requirements.

Credit Risk

Credit risk is defined as the risk that a counterparty to a transaction will be unable to fulfill its contractual obligations. Met-Ed evaluates the credit standing of a prospective counterparty based on the prospective counterparty's financial condition. Met-Ed may impose specified collateral requirements and use standardized agreements that facilitate the netting of cash flows. Met-Ed monitors the financial conditions of existing counterparties on an ongoing basis. An independent risk management group oversees credit risk.

PENNSYLVANIA ELECTRIC COMPANY
MANAGEMENT'S NARRATIVE
ANALYSIS OF RESULTS OF OPERATIONS

Penelec is a wholly owned electric utility subsidiary of FirstEnergy. Penelec provides regulated electric transmission and distribution services in 17,600 square miles of western, northern and south central Pennsylvania. The area it serves has a population of approximately 1.3 million. Penelec, as lessee of the property of its subsidiary, The Waverly Electric Light & Power Company, serves customers in the Waverly, New York vicinity. Penelec also procures generation service for those franchise customers who have elected to retain them as their power supplier. Penelec procures power under its 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: Strategy and Outlook, Risks and Challenges, Capital Resources and Liquidity, Contractual Obligations, Regulatory Matters, Environmental Matters, Other Legal Proceedings, Critical Accounting Policies and New Accounting Standards and Interpretations.

On January 25, 2012, Penelec filed a Form 15 with the SEC to deregister its securities and suspend its obligation to file periodic reports under the Securities Exchange Act of 1934, as amended, except that the registrant has filed this Annual Report on Form 10-K for the year ended December 31, 2011. This Annual Report on Form 10-K will be the last filing made by Penelec with the SEC under the Exchange Act.

Results of Operations

Net income was unchanged in 2011, compared to 2010, due to lower purchased power costs, other operating expenses and income taxes, partially offset by lower revenues and higher amortization of regulatory assets.

Revenues

Revenues decreased by $459 million, or 30%, in 2011 compared to 2010. The decrease in revenue was primarily due to lower distribution, retail generation, wholesale generation and transmission revenues.

Distribution revenues decreased by $93 million in 2011, compared to 2010, primarily due to lower rates resulting from the DSP, which eliminated the transmission component from the distribution rate beginning in 2011, partially offset by a PPUC-approved rate adjustment for NUG costs. Lower MWH deliveries to residential and commercial customers reflected decreased weather-related usage compared to 2010. Higher MWH deliveries to industrial customers were primarily due to recovering economic conditions in Penelec's service territory, compared to 2010.

Changes in distribution MWH deliveries and revenues in 2011, compared to 2010, are summarized in the following tables:

Distribution MWH Deliveries	Increase (Decrease)	
Residential	(2.2	)%
Commercial	(3.7	)%
Industrial	4.5	%
Net Decrease in Distribution Deliveries	0.1	%

Distribution Revenues	Decrease (In millions)	
Residential	$(35	)
Commercial	(31	)
Industrial	(27	)
Decrease in Distribution Revenues	$(93	)

Retail generation revenues decreased by $218 million in 2011, compared to 2010, due to lower MWH sales in all customer classes resulting from increased customer shopping. The impact of customer shopping was 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 satisfied by generation 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.

Changes in retail generation MWH sales and revenues in 2011, compared to 2010, are summarized in the following tables:

Retail Generation MWH Sales	Decrease
Residential	(8.5)%
Commercial	(53.6)%
Industrial	(92.5)%
Decrease in Retail Generation Sales	(53.1)%

Retail Generation Revenues	Increase (Decrease)
	(In millions)
Residential	$87
Commercial	(78)
Industrial	(227)
Net Decrease in Retail Generation Revenues	$(218)

Wholesale generation revenues decreased by $205 million in 2011, compared to 2010, reflecting lower RPM revenues for Penelec in the PJM market.

Transmission revenues decreased by $7 million in 2011, compared to 2010, primarily due to the termination of Penelec’s TSC rates effective January 1, 2011. Penelec deferred the difference between transmission revenues and transmission costs incurred, resulting in no material effect to earnings for the period.

Operating Expenses

Total operating expenses decreased by $446 million in 2011 as compared to 2010. The following table presents changes from the prior year by expense category:

Operating Expenses - Changes	Increase (Decrease)
	(In millions)
Purchased power costs	(467)
Other operating costs	(99)
Pensions and OPEB mark-to-market adjustment	33
Provision for depreciation	(3)
Amortization of regulatory assets, net	97
General taxes	(7)
Net Decrease in Operating Expenses	$(446)

Purchased power costs decreased by $467 million in 2011, compared to 2010, due to a decrease in MWH purchased to source generation sales requirements. Decreased power purchased from affiliates resulted from reduced requirements due to the increase in customer shopping described above and the termination of Penelec's partial requirements PSA with FES at the end of 2010. Other operating costs decreased by $99 million in 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). Increased pensions and OPEB mark-to-market adjustment charges were due to higher net actuarial losses in 2011 as compared to 2010. The amortization of regulatory assets increased by $97 million in 2011 primarily due to reduced NUG deferrals as a result of the PPUC-approved increase in Penelec’s NUG cost recovery rider in January 2011.

Other Expenses

Other expenses decreased by $3 million in 2011, compared to 2010, due to lower income from jobbing and contracting work and lower capitalized interest.

Market Risk Information

Penelec 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

Penelec is exposed to financial risks resulting from fluctuating interest rates and commodity prices, including prices for electricity, natural gas and energy transmission. FirstEnergy's Risk Policy 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. Penelec uses a variety of derivative instruments for risk management purposes including forward contracts, options, futures contracts and swaps.

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, Penelec relies on model-based information. The model provides estimates of future regional prices for electricity and an estimate of related price volatility. Penelec uses these results to develop estimates of fair value for financial reporting purposes and for internal management decision making (see Note 9, Fair Value Measurements of the Combined Notes to the Consolidated Financial Statements).

Sources of information for the valuation of commodity derivative contract assets and liabilities as of December 31, 2011, are summarized by year in the following table:

Source of Information-Fair Value by Contract Year	2012	2013	2014	2015	2016	Thereafter	Total
	(In millions)						
Prices actively quoted[(1)]	$—	$—	$—	$—	$—	$—	$—
Other external sources[(2)]	(85)	(12)	(10)	(11)	—	—	(118)
Prices based on models	—	—	—	—	1	(3)	(2)
Total[(3)]	$(85)	$(12)	$(10)	$(11)	$1	$(3)	$(120)

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

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

(3) Includes $(120) million in non-hedge commodity derivative contracts that are related to NUG contracts. NUG contracts are subject to regulatory accounting and do not materially impact earnings.

Penelec performs sensitivity analyses to estimate its exposure to the market risk of its commodity positions. Based on derivative contracts held as of December 31, 2011, an adverse 10% change in commodity prices would not have a material effect on Penelec’s net income for the next 12 months.

Interest Rate Risk

Penelec’s exposure to fluctuations in market interest rates is reduced since a significant portion of its debt has fixed interest rates. The table below presents principal amounts and related weighted average interest rates by year of maturity for Penelec’s investment portfolio and debt obligations.

Comparison of Carrying Value to Fair Value

Year of Maturity	2012	2013	2014	2015	2016	There-after	Total	Fair Value
	(In millions)							
Assets:								
Investments Other Than Cash and Cash Equivalents:								
Fixed Income						$195	$195	$195
Average interest rate						3.8%	3.8%	
Liabilities:								
Long-term Debt:								
Fixed rate			$150			$925	$1,075	$1,206
Average interest rate			5.1%			5.9%	5.8%	
Variable rate						$45	$45	$45
Average interest rate						0.1%	0.1%	

Equity Price Risk

NDT funds have been established to satisfy nuclear decommissioning obligations. Included in Penelec’s NDT are fixed income, equities and short-term investments carried at market values of approximately $106 million, $26 million and

$33 million, respectively, as of December 31, 2011, excluding $1 million of net receivables, payables and accrued income. A hypothetical 10% decrease in prices quoted by stock exchanges would result in a $3 million reduction in fair value as of December 31, 2011. Penelec's NDT is 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. A decline in the value of Penelec's NDT or a significant escalation in estimated decommissioning costs could result in additional funding requirements.

Credit Risk

Credit risk is defined as the risk that a counterparty to a transaction will be unable to fulfill its contractual obligations. Penelec evaluates the credit standing of a prospective counterparty based on the prospective counterparty's financial condition. Penelec may impose specified collateral requirements and use standardized agreements that facilitate the netting of cash flows. Penelec monitors the financial conditions of existing counterparties on an ongoing basis. An independent risk management group oversees credit risk.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The information required by ITEM 7A relating to market risk is set forth in ITEM 7. Management's Discussion and Analysis of Financial Condition and Results of Operations.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

MANAGEMENT REPORTS

Management's Responsibility for Financial Statements

The consolidated financial statements of FirstEnergy Corp. (Company) were prepared by management, who takes responsibility for their integrity and objectivity. The statements were prepared in conformity with accounting principles generally accepted in the United States and are consistent with other financial information appearing elsewhere in this report. PricewaterhouseCoopers LLP, an independent registered public accounting firm, has expressed an unqualified opinion on the Company's 2011 consolidated financial statements as stated in their audit report included herein.

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

The Company's Audit Committee consists of four independent directors whose duties include: consideration of the adequacy of the internal controls of the Company and the objectivity of financial reporting; inquiry into the number, extent, adequacy and validity of regular and special audits conducted by independent auditors and the internal auditors; and reporting to the Board of Directors the Committee's findings and any recommendation for changes in scope, methods or procedures of the auditing functions. The Committee is directly responsible for appointing the Company's independent registered public accounting firm and is charged with reviewing and approving all services performed for the Company by the independent registered public accounting firm and for reviewing and approving the related fees. The Committee reviews the independent registered public accounting firm's report on internal quality control and reviews all relationships between the independent registered public accounting firm and the Company, in order to assess the independent registered public accounting firm's independence. The Committee also reviews management's programs to monitor compliance with the Company's policies on business ethics and risk management. The Committee establishes procedures to receive and respond to complaints received by the Company regarding accounting, internal accounting controls, or auditing matters and allows for the confidential, anonymous submission of concerns by employees. The Audit Committee held eight meetings in 2011.

Management's Report on Internal Control Over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rule 13a-15(f) of the Securities Exchange Act of 1934. Using the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in Internal Control — Integrated Framework, management conducted an evaluation of the effectiveness of the Company's internal control over financial reporting under the supervision of the Chief Executive Officer and the Chief Financial Officer. Based on that evaluation, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2011. The effectiveness of the Company's internal control over financial reporting, as of December 31, 2011, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

MANAGEMENT REPORTS

Management's Responsibility for Financial Statements

The consolidated financial statements of FirstEnergy Solutions Corp. (Company) were prepared by management, who takes responsibility for their integrity and objectivity. The statements were prepared in conformity with accounting principles generally accepted in the United States and are consistent with other financial information appearing elsewhere in this report. PricewaterhouseCoopers LLP, an independent registered public accounting firm, has expressed an unqualified opinion on the Company's 2011 consolidated financial statements as stated in their audit report included herein.

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

FirstEnergy's Audit Committee consists of four independent directors whose duties include: consideration of the adequacy of the internal controls of the Company and the objectivity of financial reporting; inquiry into the number, extent, adequacy and validity of regular and special audits conducted by independent auditors and the internal auditors; and reporting to the Board of Directors the Committee's findings and any recommendation for changes in scope, methods or procedures of the auditing functions. The Committee is directly responsible for appointing the Company's independent registered public accounting firm and is charged with reviewing and approving all services performed for the Company by the independent registered public accounting firm and for reviewing and approving the related fees. The Committee reviews the independent registered public accounting firm's report on internal quality control and reviews all relationships between the independent registered public accounting firm and the Company, in order to assess the independent registered public accounting firm's independence. The Committee also reviews management's programs to monitor compliance with the Company's policies on business ethics and risk management. The Committee establishes procedures to receive and respond to complaints received by the Company regarding accounting, internal accounting controls, or auditing matters and allows for the confidential, anonymous submission of concerns by employees. The Audit Committee held eight meetings in 2011.

Management's Report on Internal Control Over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rule 13a-15(f) of the Securities Exchange Act of 1934. Using the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in Internal Control — Integrated Framework, management conducted an evaluation of the effectiveness of the Company's internal control over financial reporting under the supervision of the Chief Executive Officer and the Chief Financial Officer. Based on that evaluation, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2011.

MANAGEMENT REPORTS

Management's Responsibility for Financial Statements

The consolidated financial statements of Ohio Edison Company (Company) were prepared by management, who takes responsibility for their integrity and objectivity. The statements were prepared in conformity with accounting principles generally accepted in the United States and are consistent with other financial information appearing elsewhere in this report. PricewaterhouseCoopers LLP, an independent registered public accounting firm, has expressed an unqualified opinion on the Company's 2011 consolidated financial statements as stated in their audit report included herein.

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

FirstEnergy's Audit Committee consists of four independent directors whose duties include: consideration of the adequacy of the internal controls of the Company and the objectivity of financial reporting; inquiry into the number, extent, adequacy and validity of regular and special audits conducted by independent auditors and the internal auditors; and reporting to the Board of Directors the Committee's findings and any recommendation for changes in scope, methods or procedures of the auditing functions. The Committee is directly responsible for appointing the Company's independent registered public accounting firm and is charged with reviewing and approving all services performed for the Company by the independent registered public accounting firm and for reviewing and approving the related fees. The Committee reviews the independent registered public accounting firm's report on internal quality control and reviews all relationships between the independent registered public accounting firm and the Company, in order to assess the independent registered public accounting firm's independence. The Committee also reviews management's programs to monitor compliance with the Company's policies on business ethics and risk management. The Committee establishes procedures to receive and respond to complaints received by the Company regarding accounting, internal accounting controls, or auditing matters and allows for the confidential, anonymous submission of concerns by employees. The Audit Committee held eight meetings in 2011.

Management's Report on Internal Control Over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rule 13a-15(f) of the Securities Exchange Act of 1934. Using the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in Internal Control — Integrated Framework, management conducted an evaluation of the effectiveness of the Company's internal control over financial reporting under the supervision of the Chief Executive Officer and the Chief Financial Officer. Based on that evaluation, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2011.

MANAGEMENT REPORTS

Management’s Responsibility for Financial Statements

The consolidated financial statements of The Cleveland Electric Illuminating Company (Company) were prepared by management, who takes responsibility for their integrity and objectivity. The statements were prepared in conformity with accounting principles generally accepted in the United States and are consistent with other financial information appearing elsewhere in this report. PricewaterhouseCoopers LLP, an independent registered public accounting firm, has expressed an unqualified opinion on the Company’s 2011 consolidated financial statements as stated in their audit report included herein.

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

FirstEnergy’s Audit Committee consists of four independent directors whose duties include: consideration of the adequacy of the internal controls of the Company and the objectivity of financial reporting; inquiry into the number, extent, adequacy and validity of regular and special audits conducted by independent auditors and the internal auditors; and reporting to the Board of Directors the Committee’s findings and any recommendation for changes in scope, methods or procedures of the auditing functions. The Committee is directly responsible for appointing the Company’s independent registered public accounting firm and is charged with reviewing and approving all services performed for the Company by the independent registered public accounting firm and for reviewing and approving the related fees. The Committee reviews the independent registered public accounting firm’s report on internal quality control and reviews all relationships between the independent registered public accounting firm and the Company, in order to assess the independent registered public accounting firm’s independence. The Committee also reviews management’s programs to monitor compliance with the Company’s policies on business ethics and risk management. The Committee establishes procedures to receive and respond to complaints received by the Company regarding accounting, internal accounting controls, or auditing matters and allows for the confidential, anonymous submission of concerns by employees. The Audit Committee held eight meetings in 2011.

Management’s Report on Internal Control Over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rule 13a-15(f) of the Securities Exchange Act of 1934. Using the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in Internal Control — Integrated Framework, management conducted an evaluation of the effectiveness of the Company’s internal control over financial reporting under the supervision of the Chief Executive Officer and the Chief Financial Officer. Based on that evaluation, management concluded that the Company’s internal control over financial reporting was effective as of December 31, 2011.

MANAGEMENT REPORTS

Management's Responsibility for Financial Statements

The consolidated financial statements of The Toledo Edison Company (Company) were prepared by management, who takes responsibility for their integrity and objectivity. The statements were prepared in conformity with accounting principles generally accepted in the United States and are consistent with other financial information appearing elsewhere in this report. PricewaterhouseCoopers LLP, an independent registered public accounting firm, has expressed an unqualified opinion on the Company's 2011 consolidated financial statements as stated in their audit report included herein.

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

FirstEnergy's Audit Committee consists of four independent directors whose duties include: consideration of the adequacy of the internal controls of the Company and the objectivity of financial reporting; inquiry into the number, extent, adequacy and validity of regular and special audits conducted by independent auditors and the internal auditors; and reporting to the Board of Directors the Committee's findings and any recommendation for changes in scope, methods or procedures of the auditing functions. The Committee is directly responsible for appointing the Company's independent registered public accounting firm and is charged with reviewing and approving all services performed for the Company by the independent registered public accounting firm and for reviewing and approving the related fees. The Committee reviews the independent registered public accounting firm's report on internal quality control and reviews all relationships between the independent registered public accounting firm and the Company, in order to assess the independent registered public accounting firm's independence. The Committee also reviews management's programs to monitor compliance with the Company's policies on business ethics and risk management. The Committee establishes procedures to receive and respond to complaints received by the Company regarding accounting, internal accounting controls, or auditing matters and allows for the confidential, anonymous submission of concerns by employees. The Audit Committee held eight meetings in 2011.

Management's Report on Internal Control Over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rule 13a-15(f) of the Securities Exchange Act of 1934. Using the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in Internal Control — Integrated Framework, management conducted an evaluation of the effectiveness of the Company's internal control over financial reporting under the supervision of the Chief Executive Officer and the Chief Financial Officer. Based on that evaluation, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2011.

MANAGEMENT REPORTS

Management's Responsibility for Financial Statements

The consolidated financial statements of Jersey Central Power & Light Company (Company) were prepared by management, who takes responsibility for their integrity and objectivity. The statements were prepared in conformity with accounting principles generally accepted in the United States and are consistent with other financial information appearing elsewhere in this report. PricewaterhouseCoopers LLP, an independent registered public accounting firm, has expressed an unqualified opinion on the Company's 2011 consolidated financial statements as stated in their audit report included herein.

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

FirstEnergy's Audit Committee consists of four independent directors whose duties include: consideration of the adequacy of the internal controls of the Company and the objectivity of financial reporting; inquiry into the number, extent, adequacy and validity of regular and special audits conducted by independent auditors and the internal auditors; and reporting to the Board of Directors the Committee's findings and any recommendation for changes in scope, methods or procedures of the auditing functions. The Committee is directly responsible for appointing the Company's independent registered public accounting firm and is charged with reviewing and approving all services performed for the Company by the independent registered public accounting firm and for reviewing and approving the related fees. The Committee reviews the independent registered public accounting firm's report on internal quality control and reviews all relationships between the independent registered public accounting firm and the Company, in order to assess the independent registered public accounting firm's independence. The Committee also reviews management's programs to monitor compliance with the Company's policies on business ethics and risk management. The Committee establishes procedures to receive and respond to complaints received by the Company regarding accounting, internal accounting controls, or auditing matters and allows for the confidential, anonymous submission of concerns by employees. The Audit Committee held eight meetings in 2011.

Management's Report on Internal Control Over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rule 13a-15(f) of the Securities Exchange Act of 1934. Using the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in Internal Control — Integrated Framework, management conducted an evaluation of the effectiveness of the Company's internal control over financial reporting under the supervision of the Chief Executive Officer and the Chief Financial Officer. Based on that evaluation, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2011.

MANAGEMENT REPORTS

Management's Responsibility for Financial Statements

The consolidated financial statements of Metropolitan Edison Company (Company) were prepared by management, who takes responsibility for their integrity and objectivity. The statements were prepared in conformity with accounting principles generally accepted in the United States and are consistent with other financial information appearing elsewhere in this report. PricewaterhouseCoopers LLP, an independent registered public accounting firm, has expressed an unqualified opinion on the Company's 2011 consolidated financial statements as stated in their audit report included herein.

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

FirstEnergy's Audit Committee consists of four independent directors whose duties include: consideration of the adequacy of the internal controls of the Company and the objectivity of financial reporting; inquiry into the number, extent, adequacy and validity of regular and special audits conducted by independent auditors and the internal auditors; and reporting to the Board of Directors the Committee's findings and any recommendation for changes in scope, methods or procedures of the auditing functions. The Committee is directly responsible for appointing the Company's independent registered public accounting firm and is charged with reviewing and approving all services performed for the Company by the independent registered public accounting firm and for reviewing and approving the related fees. The Committee reviews the independent registered public accounting firm's report on internal quality control and reviews all relationships between the independent registered public accounting firm and the Company, in order to assess the independent registered public accounting firm's independence. The Committee also reviews management's programs to monitor compliance with the Company's policies on business ethics and risk management. The Committee establishes procedures to receive and respond to complaints received by the Company regarding accounting, internal accounting controls, or auditing matters and allows for the confidential, anonymous submission of concerns by employees. The Audit Committee held eight meetings in 2011.

Management's Report on Internal Control Over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rule 13a-15(f) of the Securities Exchange Act of 1934. Using the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in Internal Control — Integrated Framework, management conducted an evaluation of the effectiveness of the Company's internal control over financial reporting under the supervision of the Chief Executive Officer and the Chief Financial Officer. Based on that evaluation, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2011.

MANAGEMENT REPORTS

Management's Responsibility for Financial Statements

The consolidated financial statements of Pennsylvania Electric Company (Company) were prepared by management, who takes responsibility for their integrity and objectivity. The statements were prepared in conformity with accounting principles generally accepted in the United States and are consistent with other financial information appearing elsewhere in this report. PricewaterhouseCoopers LLP, an independent registered public accounting firm, has expressed an unqualified opinion on the Company's 2011 consolidated financial statements as stated in their audit report included herein.

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

FirstEnergy's Audit Committee consists of four independent directors whose duties include: consideration of the adequacy of the internal controls of the Company and the objectivity of financial reporting; inquiry into the number, extent, adequacy and validity of regular and special audits conducted by independent auditors and the internal auditors; and reporting to the Board of Directors the Committee's findings and any recommendation for changes in scope, methods or procedures of the auditing functions. The Committee is directly responsible for appointing the Company's independent registered public accounting firm and is charged with reviewing and approving all services performed for the Company by the independent registered public accounting firm and for reviewing and approving the related fees. The Committee reviews the independent registered public accounting firm's report on internal quality control and reviews all relationships between the independent registered public accounting firm and the Company, in order to assess the independent registered public accounting firm's independence. The Committee also reviews management's programs to monitor compliance with the Company's policies on business ethics and risk management. The Committee establishes procedures to receive and respond to complaints received by the Company regarding accounting, internal accounting controls, or auditing matters and allows for the confidential, anonymous submission of concerns by employees. The Audit Committee held eight meetings in 2011.

Management's Report on Internal Control Over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rule 13a-15(f) of the Securities Exchange Act of 1934. Using the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in Internal Control — Integrated Framework, management conducted an evaluation of the effectiveness of the Company's internal control over financial reporting under the supervision of the Chief Executive Officer and the Chief Financial Officer. Based on that evaluation, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2011.

Report of Independent Registered Public Accounting Firm

To the Stockholders and Board of Directors of FirstEnergy Corp.:

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, comprehensive income, common stockholders' equity, and cash flows present fairly, in all material respects, the financial position of FirstEnergy Corp. and its subsidiaries at December 31, 2011 and 2010, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2011 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under Item 15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2011, based on criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control over Financial Reporting. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

As discussed in Note 1 to the consolidated financial statements, in 2011 the Company changed its method of accounting for pension and other postemployment benefit plans. All periods have been retroactively restated for this accounting change.

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

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

/s/ PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP

Cleveland, Ohio
February 28, 2012

Report of Independent Registered Public Accounting Firm

To the Stockholder and Board of
Directors of FirstEnergy Solutions Corp.:

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, comprehensive income, common stockholder's equity, and cash flows present fairly, in all material respects, the financial position of FirstEnergy Solutions Corp. and its subsidiaries at December 31, 2011 and 2010, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2011 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under Item 15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and financial statement schedule based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 1 to the consolidated financial statements, in 2011 the Company changed its method of accounting for pension and other postemployment benefit plans. All periods have been retroactively restated for this accounting change.

/s/ PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP

Cleveland, Ohio
February 28, 2012

Report of Independent Registered Public Accounting Firm

To the Stockholder and Board of
Directors of Ohio Edison Company:

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, comprehensive income, common stockholder's equity, and cash flows present fairly, in all material respects, the financial position of Ohio Edison Company and its subsidiaries at December 31, 2011 and 2010, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2011 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under Item 15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and financial statement schedule based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 1 to the consolidated financial statements, in 2011 the Company changed its method of accounting for pension and other postemployment benefit plans. All periods have been retroactively restated for this accounting change.

/s/ PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP

Cleveland, Ohio
February 28, 2012

Report of Independent Registered Public Accounting Firm

To the Stockholder and Board of Directors of
The Cleveland Electric Illuminating Company:

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, comprehensive income, common stockholder's equity, and cash flows present fairly, in all material respects, the financial position of The Cleveland Electric Illuminating Company and its subsidiaries at December 31, 2011 and 2010, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2011 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under Item 15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and financial statement schedule based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 1 to the consolidated financial statements, in 2011 the Company changed its method of accounting for pension and other postemployment benefit plans. All periods have been retroactively restated for this accounting change.

/s/ PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP

Cleveland, Ohio
February 28, 2012

Report of Independent Registered Public Accounting Firm

To the Stockholder and Board of
Directors of The Toledo Edison Company:

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, comprehensive income, common stockholder's equity, and cash flows present fairly, in all material respects, the financial position of The Toledo Edison Company and its subsidiary at December 31, 2011 and 2010, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2011 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under Item 15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and financial statement schedule based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 1 to the consolidated financial statements, in 2011 the Company changed its method of accounting for pension and other postemployment benefit plans. All periods have been retroactively restated for this accounting change.

/s/ PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP

Cleveland, Ohio
February 28, 2012

Report of Independent Registered Public Accounting Firm

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

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, comprehensive income, common stockholder's equity, and cash flows present fairly, in all material respects, the financial position of Jersey Central Power & Light Company and its subsidiaries at December 31, 2011 and 2010, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2011 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under Item 15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and financial statement schedule based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 1 to the consolidated financial statements, in 2011 the Company changed its method of accounting for pension and other postemployment benefit plans. All periods have been retroactively restated for this accounting change.

/s/ PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP

Cleveland, Ohio
February 28, 2012

Report of Independent Registered Public Accounting Firm

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

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, comprehensive income, common stockholder's equity, and cash flows present fairly, in all material respects, the financial position of Metropolitan Edison Company and its subsidiaries at December 31, 2011 and 2010, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2011 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under Item 15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and financial statement schedule based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 1 to the consolidated financial statements, in 2011 the Company changed its method of accounting for pension and other postemployment benefit plans. All periods have been retroactively restated for this accounting change.

/s/ PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP

Cleveland, Ohio
February 28, 2012

Report of Independent Registered Public Accounting Firm

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

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, comprehensive income, common stockholder's equity, and cash flows present fairly, in all material respects, the financial position of Pennsylvania Electric Company and its subsidiaries at December 31, 2011 and 2010, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2011 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under Item 15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and financial statement schedule based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 1 to the consolidated financial statements, in 2011 the Company changed its method of accounting for pension and other postemployment benefit plans. All periods have been retroactively restated for this accounting change.

/s/ PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP

Cleveland, Ohio
February 28, 2012

FIRSTENERGY CORP.
CONSOLIDATED STATEMENTS OF INCOME

(In millions, except per share amounts)	For the Years Ended December 31, 2011	2010	2009
REVENUES:			
Electric utilities	$10,396	$9,815	$11,139
Unregulated businesses	5,862	3,524	1,834
Total revenues*	16,258	13,339	12,973
OPERATING EXPENSES:			
Fuel	2,317	1,432	1,153
Purchased power	4,986	4,624	4,730
Other operating expenses	3,909	2,696	2,551
Pensions and OPEB mark-to-market adjustment	507	190	321
Provision for depreciation	1,121	768	757
Amortization of regulatory assets, net	329	722	1,019
General taxes	978	776	753
Impairment of long-lived assets	413	388	6
Total operating expenses	14,560	11,596	11,290
OPERATING INCOME	1,698	1,743	1,683
OTHER INCOME (EXPENSE):			
Gain on partial sale of Signal Peak	569	—	—
Investment income	114	117	204
Interest expense	(1,008)	(845)	(978)
Capitalized interest	70	165	131
Total other expense	(255)	(563)	(643)
INCOME BEFORE INCOME TAXES	1,443	1,180	1,040
INCOME TAXES	574	462	184
NET INCOME	869	718	856
Loss attributable to noncontrolling interest	(16)	(24)	(16)
EARNINGS AVAILABLE TO FIRSTENERGY CORP.	$885	$742	$872
EARNINGS PER SHARE OF COMMON STOCK:			
Basic	$2.22	$2.44	$2.87
Diluted	$2.21	$2.42	$2.85
WEIGHTED AVERAGE NUMBER OF SHARES OUTSTANDING			
Basic	399	304	304
Diluted	401	305	306

* Includes $486 million, $428 million and $395 million of excise tax collections in 2011, 2010 and 2009, respectively.

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

FIRSTENERGY CORP.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(In millions)	For the Years Ended December 31, 2011	2010	2009
NET INCOME	$869	$718	$856
OTHER COMPREHENSIVE INCOME (LOSS):			
Pensions and OPEB prior service costs	(90)	(220)	275
Unrealized gain on derivative hedges	23	36	51
Change in unrealized gain on available-for-sale securities	19	8	(74)
Other comprehensive income (loss)	(48)	(176)	252
Income taxes (benefits) on other comprehensive income (loss)	(49)	(74)	128
Other comprehensive income (loss), net of tax	1	(102)	124
COMPREHENSIVE INCOME	870	616	980
COMPREHENSIVE LOSS ATTRIBUTABLE TO NONCONTROLLING INTEREST	(16)	(24)	(16)
COMPREHENSIVE INCOME AVAILABLE TO FIRSTENERGY CORP.	$886	$640	$996

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

FIRSTENERGY CORP.
CONSOLIDATED BALANCE SHEETS

(In millions, except share amounts)	As of December 31, 2011	2010
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$202	$1,019
Receivables-		
Customers, net of allowance for uncollectible accounts of $37 in 2011 and $36 in 2010	1,525	1,392
Other, net of allowance for uncollectible accounts of $3 in 2011 and $8 in 2010	269	176
Materials and supplies, at average cost	811	638
Prepaid taxes	191	199
Derivatives	235	182
Other	122	92
	3,355	3,698
PROPERTY, PLANT AND EQUIPMENT:		
In service	40,122	30,276
Less — Accumulated provision for depreciation	11,839	11,283
	28,283	18,993
Construction work in progress	2,054	1,517
	30,337	20,510
INVESTMENTS:		
Nuclear plant decommissioning trusts	2,112	1,973
Investments in lease obligation bonds	402	476
Other	1,008	553
	3,522	3,002
DEFERRED CHARGES AND OTHER ASSETS:		
Goodwill	6,441	5,575
Regulatory assets	2,030	1,830
Other	1,641	916
	10,112	8,321
	$47,326	$35,531
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Currently payable long-term debt	$1,621	$1,486
Short-term borrowings	—	700
Accounts payable	1,174	872
Accrued taxes	558	332
Accrued compensation and benefits	384	315
Derivatives	218	266
Other	900	733
	4,855	4,704
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	9,765	5,444
Accumulated other comprehensive income	426	425

Retained earnings	3,047	3,084
Total common stockholders' equity	13,280	8,984
Noncontrolling interest	19	(32)
Total equity	13,299	8,952
Long-term debt and other long-term obligations	15,716	12,579
	29,015	21,531
NONCURRENT LIABILITIES:		
Accumulated deferred income taxes	5,670	3,160
Retirement benefits	2,823	1,868
Asset retirement obligations	1,497	1,407
Deferred gain on sale and leaseback transaction	925	959
Adverse power contract liability	469	466
Other	2,072	1,436
	13,456	9,296
COMMITMENTS, GUARANTEES AND CONTINGENCIES (Notes 6 and 16)		
	$47,326	$35,531

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 COMMON STOCKHOLDERS' EQUITY

(In millions, except share amounts)	Common Stock Number of Shares	Common Stock Par Value	Other Paid-In Capital	Accumulated Other Comprehensive Income	Retained Earnings
Balance, January 1, 2009	304,835,407	$31	$5,473	$403	$2,810
Earnings available to FirstEnergy Corp.					872
Change in unrealized loss on derivative hedges, net of $24 million of income taxes				27	
Change in unrealized gain on investments, net of $31 million of income tax benefits				(43)	
Pensions and OPEB, net of $135 million of income taxes (Note 3)				140	
Stock options exercised			(3)		
Restricted stock units			7		
Stock-based compensation			1		
Acquisition adjustment of non-controlling interest (Note 8)			(30)		
Cash dividends declared on common stock					(670)
Balance, December 31, 2009	304,835,407	31	5,448	527	3,012
Earnings available to FirstEnergy Corp.					742
Change in unrealized loss on derivative hedges, net of $14 million of income taxes				22	
Change in unrealized gain on investments, net of $3 million of income taxes				5	
Pensions and OPEB, net of $91 million of income tax benefits (Note 3)				(129)	
Stock options exercised			(2)		
Restricted stock units			(3)		
Stock-based compensation			1		
Cash dividends declared on common stock					(670)
Balance, December 31, 2010	304,835,407	31	5,444	425	3,084
Earnings available to FirstEnergy Corp.					885
Change in unrealized loss on derivative hedges, net of $8 million of income taxes				15	
Change in unrealized gain on investments, net of $7 million of income taxes				12	
Pensions and OPEB, net of $64 million of income tax benefits (Note 3)				(26)	
Stock options exercised			5		
Restricted stock units			(2)		
Stock-based compensation			2		
Allegheny merger	113,381,030	11	4,316		
Cash dividends declared on common stock					(922)
Balance, December 31, 2011	418,216,437	$42	$9,765	$426	$3,047

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

FIRSTENERGY CORP.
CONSOLIDATED STATEMENTS OF CASH FLOWS

	As of December 31,		
(In millions)	2011	2010	2009
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	$869	$718	$856
Adjustments to reconcile net income to net cash from operating activities-			
Provision for depreciation	1,121	768	757
Amortization of regulatory assets, net	329	722	1,019
Nuclear fuel and lease amortization	201	168	128
Deferred purchased power and other costs	(278)	(254)	(338)
Deferred income taxes and investment tax credits, net	798	450	323
Impairments of long-lived assets (Note 11)	413	388	6
Investment impairments (Note 1)	19	33	62
Deferred rents and lease market valuation liability	(49)	(54)	(52)
Stock based compensation	(10)	(1)	20
Pensions and OPEB mark-to-market adjustment	507	190	321
Accrued compensation and retirement benefits	(82)	(65)	(124)
Gain on asset sales	(545)	(2)	(27)
Cash collateral, net	(79)	(26)	30
Gain on sales of investment securities held in trusts, net	(59)	(55)	(176)
Loss on debt redemption	—	5	146
Interest rate swap transactions	—	129	—
Commodity derivative transactions, net (Note 10)	(27)	(81)	229
Pension trust contributions	(372)	—	(500)
Uncertain tax positions	(12)	(34)	(210)
Acquisition of supply requirements	—	—	(93)
Decrease (increase) in operating assets-			
Receivables	147	(177)	75
Materials and supplies	14	2	(11)
Prepayments and other current assets	101	100	(19)
Increase (decrease) in operating liabilities-			
Accounts payable	35	43	50
Accrued taxes	91	57	(103)
Accrued interest	(12)	7	67
Other	(57)	45	29
Net cash provided from operating activities	3,063	3,076	2,465
CASH FLOWS FROM FINANCING ACTIVITIES:			
New financing-			
Long-term debt	604	1,099	4,632
Redemptions and repayments-			
Long-term debt	(1,909)	(1,015)	(2,610)
Short-term borrowings, net	(700)	(378)	(1,246)
Common stock dividend payments	(881)	(670)	(670)
Other	(38)	(19)	(57)
Net cash provided from (used for) financing activities	(2,924)	(983)	49

CASH FLOWS FROM INVESTING ACTIVITIES:			
Property additions	(2,278)	(1,963)	(2,203)
Proceeds from asset sales	840	117	21
Sales of investment securities held in trusts	4,207	3,172	2,229
Purchases of investment securities held in trusts	(4,309)	(3,219)	(2,306)
Customer acquisition costs	(3)	(113)	—
Cash investments (Note 9)	60	66	60
Cash received in Allegheny merger	590	—	—
Cost of removal	(114)	(35)	(41)
Other	51	27	55
Net cash used for investing activities	(956)	(1,948)	(2,185)
Net change in cash and cash equivalents	(817)	145	329
Cash and cash equivalents at beginning of year	1,019	874	545
Cash and cash equivalents at end of year	$202	$1,019	$874
SUPPLEMENTAL CASH FLOW INFORMATION:			
Non-cash transaction: merger with Allegheny, common stock issued	$4,354	$—	$—
Cash paid (received) during the year-			
Interest (net of amounts capitalized)	$935	$662	$718
Income taxes	$(358)	$(42)	$173

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

FIRSTENERGY SOLUTIONS CORP.
CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME

	For the Years Ended December 31,		
(In millions)	2011	2010	2009
STATEMENTS OF INCOME			
REVENUES:			
Electric sales to affiliates (Note 17)	$752	$2,227	$2,826
Electric sales to non-affiliates	4,502	3,252	1,447
Other	223	349	455
Total revenues	5,477	5,828	4,728
OPERATING EXPENSES:			
Fuel	1,344	1,403	1,129
Purchased power from affiliates (Note 17)	242	371	222
Purchased power from non-affiliates	1,378	1,585	996
Other operating expenses	1,630	1,230	1,143
Pensions and OPEB mark-to-market adjustment	171	107	150
Provision for depreciation	275	246	262
General taxes	124	94	87
Impairment of long-lived assets	294	388	6
Total operating expenses	5,458	5,424	3,995
OPERATING INCOME	19	404	733
OTHER INCOME (EXPENSE) (Note 17):			
Investment income	57	59	125
Miscellaneous income	30	17	13
Interest expense	(211)	(216)	(152)
Capitalized interest	35	92	60
Total other income (expense)	(89)	(48)	46
INCOME (LOSS) BEFORE INCOME TAXES	(70)	356	779
INCOME TAXES (BENEFITS)	(11)	125	281
NET INCOME (LOSS)	$(59)	$231	$498
STATEMENTS OF COMPREHENSIVE INCOME			
NET INCOME (LOSS)	$(59)	$231	$498
OTHER COMPREHENSIVE INCOME			
Pensions and OPEB prior service costs	(12)	(30)	68
Unrealized gain (loss) on derivative hedges	13	8	(49)
Change in unrealized gain on available for sale securities	15	23	18
Other comprehensive income	16	1	37
Income taxes on other comprehensive income	2	4	14
Other comprehensive income (loss), net of tax	14	(3)	23
COMPREHENSIVE INCOME (LOSS)	$(45)	$228	$521

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

FIRSTENERGY SOLUTIONS CORP.
CONSOLIDATED BALANCE SHEETS

	As of December 31,	
(In millions, except share amounts)	2011	2010
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$7	$9
Receivables-		
Customers, net of allowance for uncollectible accounts of $16 in 2011 and $17 in 2010	424	366
Affiliated companies	600	478
Other, net of allowance for uncollectible accounts of $3 in 2011 and $7 in 2010	61	90
Notes receivable from affiliated companies	383	397
Materials and supplies, at average cost	492	545
Derivatives	219	181
Prepayments and other	38	60
	2,224	2,126
PROPERTY, PLANT AND EQUIPMENT:		
In service	10,983	11,427
Less — Accumulated provision for depreciation	4,110	4,038
	6,873	7,389
Construction work in progress	1,014	1,063
	7,887	8,452
INVESTMENTS:		
Nuclear plant decommissioning trusts	1,223	1,146
Other	7	12
	1,230	1,158
DEFERRED CHARGES AND OTHER ASSETS:		
Customer intangibles	123	134
Goodwill	24	24
Property taxes	43	41
Unamortized sale and leaseback costs	80	73
Derivatives	118	98
Other	90	49
	478	419
	$11,819	$12,155
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Currently payable long-term debt	$905	$1,132
Short-term borrowings - affiliated companies	—	12
Accounts payable-		
Affiliated companies	436	466
Other	220	241
Accrued taxes	227	70
Derivatives	189	266
Other	261	252
	2,238	2,439
CAPITALIZATION:		
Common stockholder’s equity -		

Common stock, without par value, authorized 750 shares - 7 shares outstanding	1,570	1,567
Accumulated other comprehensive income	76	62
Retained earnings	1,931	1,990
Total equity	3,577	3,619
Long-term debt and other long-term obligations	2,799	3,181
	6,376	6,800
NONCURRENT LIABILITIES:		
Deferred gain on sale and leaseback transaction	925	959
Accumulated deferred income taxes	286	67
Asset retirement obligations	904	892
Retirement benefits	356	285
Lease market valuation liability	171	217
Other	563	496
	3,205	2,916
COMMITMENTS, GUARANTEES AND CONTINGENCIES (Notes 6 & 16)		
	$11,819	$12,155

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

FIRSTENERGY SOLUTIONS CORP.
CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDER'S EQUITY

(In millions, except share amounts)	Common Stock Number of Shares	Common Stock Carrying Value	Accumulated Other Comprehensive Income	Retained Earnings
Balance, January 1, 2009	7	$1,541	$42	$1,261
Net income				498
Change in unrealized loss on derivative instruments, net of $7 of income taxes			11	
Change in unrealized gain on investments, net of $21 of income tax benefits			(28)	
Pensions and OPEB, net of $28 of income taxes (Note 3)			40	
Stock options exercised, restricted stock units and other adjustments		1		
Consolidated tax benefit allocation		3		
Balance, December 31, 2009	7	1,545	65	1,759
Net income				231
Change in unrealized gain on derivative instruments, net of $9 of income taxes			14	
Change in unrealized gain on investments, net of $3 of income taxes			5	
Pensions and OPEB, net of $8 of income tax benefits (Note 3)			(22)	
Consolidated tax benefit allocation		22		
Balance, December 31, 2010	7	1,567	62	1,990
Net loss				(59)
Change in unrealized gain on derivative instruments, net of $5 of income taxes			7	
Change in unrealized gain on investments, net of $6 of income taxes			10	
Pensions and OPEB, net of $9 of income tax benefits (Note 3)			(3)	
Consolidated tax benefit allocation		3		
Balance, December 31, 2011	7	$1,570	$76	$1,931

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

	For the Years Ended December 31,		
(In millions)	2011	2010	2009
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net Income (loss)	$(59)	$231	$498
Adjustments to reconcile net income to net cash from operating activities-			
Provision for depreciation	275	246	262
Nuclear fuel and lease amortization	200	172	130
Deferred rents and lease market valuation liability	(42)	(47)	(46)
Deferred income taxes and investment tax credits, net	199	150	186
Impairments of long-lived assets (Note 11)	294	388	6
Investment impairments (Note 1)	17	32	57
Pensions and OPEB mark-to-market adjustment	171	107	150
Accrued compensation and retirement benefits	(41)	(25)	(34)
Commodity derivative transactions, net (Note 10)	(68)	(81)	229
Gain on investment securities held in trusts, net	(50)	(51)	(158)
Acquisition of supply requirements	—	—	(93)
Cash collateral, net	(88)	(7)	20
Affiliated company lease assignment	—	—	71
Decrease (increase) in operating assets-			
Receivables	(126)	(362)	(34)
Materials and supplies	16	(11)	13
Prepayments and other current assets	22	42	(26)
Increase (decrease) in operating liabilities-			
Accounts payable	(54)	(27)	68
Accrued taxes	159	2	6
Accrued interest	—	(2)	46
Other	(6)	29	23
Net cash provided from operating activities	819	786	1,374
CASH FLOWS FROM FINANCING ACTIVITIES:			
New financing-			
Long-term debt	247	715	2,438
Short-term borrowings, net	(11)	2	—
Redemptions and repayments-			
Long-term debt	(856)	(772)	(709)
Short-term borrowings, net	—	—	(1,156)
Other	(11)	(2)	(21)
Net cash provided from (used for) financing activities	(631)	(57)	552
CASH FLOWS FROM INVESTING ACTIVITIES:			
Property additions	(749)	(1,035)	(1,223)
Proceeds from asset sales	599	117	18
Sales of investment securities held in trusts	1,843	1,927	1,379
Purchases of investment securities held in trusts	(1,890)	(1,974)	(1,406)
Loans to affiliated companies, net	14	408	(676)
Customer acquisition costs	(3)	(113)	—

Leasehold improvement payments to affiliated companies	—	(51)	—
Other	(4)	1	(18)
Net cash used for investing activities	(190)	(720)	(1,926)
Net change in cash and cash equivalents	(2)	9	—
Cash and cash equivalents at beginning of period	9	—	—
Cash and cash equivalents at end of period	$7	$9	$—
SUPPLEMENTAL CASH FLOW INFORMATION:			
Cash paid (received) during the year-			
Interest (net of amounts capitalized)	$167	$117	$38
Income taxes	$(387)	$140	$96

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

OHIO EDISON COMPANY
CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME

	For the Years Ended December 31,		
(In millions)	2011	2010	2009
STATEMENTS OF INCOME			
REVENUES (Note 17):			
Electric sales	$1,526	$1,729	$2,418
Excise and gross receipts tax collections	107	107	99
Total revenues	1,633	1,836	2,517
OPERATING EXPENSES (Note 17):			
Purchased power from affiliates	287	522	993
Purchased power from non-affiliates	272	316	481
Other operating expenses	451	342	439
Pensions and OPEB mark-to-market adjustment	43	24	26
Provision for depreciation	93	91	92
Amortization of regulatory assets, net	30	63	94
General taxes	190	183	171
Total operating expenses	1,366	1,541	2,296
OPERATING INCOME	267	295	221
OTHER INCOME (EXPENSE) (Note 17):			
Investment income	23	22	47
Miscellaneous income	2	4	3
Interest expense	(88)	(89)	(91)
Capitalized interest	2	1	1
Total other expense	(61)	(62)	(40)
INCOME BEFORE INCOME TAXES	206	233	181
INCOME TAXES	78	78	62
NET INCOME	$128	$155	$119
STATEMENTS OF COMPREHENSIVE INCOME			
NET INCOME	$128	$155	$119
OTHER COMPREHENSIVE INCOME (LOSS):			
Pensions and OPEB prior service costs	(43)	(31)	53
Change in unrealized gain on available-for-sale securities	—	—	(9)
Other comprehensive income (loss)	(43)	(31)	44
Income tax benefits on other comprehensive income	(15)	(9)	19
Other comprehensive income (loss), net of tax	(28)	(22)	25
COMPREHENSIVE INCOME	$100	$133	$144

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

OHIO EDISON COMPANY
CONSOLIDATED BALANCE SHEETS

	As of December 31,	
(In millions, except share amounts)	2011	2010
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$26	$420
Receivables-		
Customers, net of allowance for uncollectible accounts of $4 in 2011 and 2010	163	177
Affiliated companies	86	118
Other	41	12
Notes receivable from affiliated companies	181	17
Prepayments and other	17	7
	514	751
UTILITY PLANT:		
In service	3,358	3,222
Less — Accumulated provision for depreciation	1,267	1,218
	2,091	2,004
Construction work in progress	91	45
	2,182	2,049
OTHER PROPERTY AND INVESTMENTS:		
Investment in lease obligation bonds (Note 6)	163	190
Nuclear plant decommissioning trusts	137	127
Other	90	96
	390	413
DEFERRED CHARGES AND OTHER ASSETS:		
Regulatory assets	363	403
Pension assets (Note 3)	5	29
Property taxes	81	71
Unamortized sale and leaseback costs	25	30
Other	14	18
	488	551
	$3,574	$3,764
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Currently payable long-term debt	$2	$1
Short-term borrowings - affiliated companies	—	142
Accounts payable-		
Affiliated companies	119	99
Other	35	30
Accrued taxes	88	80
Accrued interest	25	25
Other	79	76
	348	453
CAPITALIZATION:		
Common stockholder’s equity -		
Common stock, without par value, authorized 175,000,000 shares - 60 shares outstanding	747	913
Accumulated other comprehensive income	54	82

Accumulated deficit	(84)	(112)
Total common stockholder’s equity	717	883
Noncontrolling interest	5	6
Total equity	722	889
Long-term debt and other long-term obligations	1,155	1,152
	1,877	2,041
NONCURRENT LIABILITIES:		
Accumulated deferred income taxes	787	737
Accumulated deferred investment tax credits	9	10
Retirement benefits	213	184
Asset retirement obligations	71	74
Other	269	265
	1,349	1,270
COMMITMENTS AND CONTINGENCIES (Notes 6 and 16)		
	$3,574	$3,764

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

OHIO EDISON COMPANY
CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDER'S EQUITY

(In millions, except share amounts)	Common Stock Number of Shares	Common Stock Carrying Value	Accumulated Other Comprehensive Income	Retained Earnings (Accumulated Deficit)
Balance, January 1, 2009	60	$1,185	$79	$5
Net income				119
Change in unrealized gain on investments, net of $4 of income tax benefits			(5)	
Pensions and OPEB, net of $23 of income taxes (Note 3)			30	
Stock-based compensation		5		
Cash dividends declared on common stock				(346)
Cash dividend as return of capital		(74)		
Balance, December 31, 2009	60	1,116	104	(222)
Net income				155
Pensions and OPEB, net of $9 of income taxes (Note 3)			(22)	
Consolidated tax benefit allocation		2		
Cash dividends declared on common stock				(45)
Cash dividends as return of capital		(205)		
Balance, December 31, 2010	60	913	82	(112)
Net income				128
Pensions and OPEB, net of $15 of income tax benefits (Note 3)			(28)	
Consolidated tax benefit allocation		2		
Cash dividends declared on common stock				(100)
Cash dividends as return of capital		(168)		
Balance, December 31, 2011	60	$747	$54	$(84)

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

OHIO EDISON COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS

	For the Years Ended December 31,		
(In millions)	2011	2010	2009
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	$128	$155	$119
Adjustments to reconcile net income to net cash from operating activities-			
Provision for depreciation	93	91	92
Amortization of regulatory assets, net	30	63	94
Amortization of lease costs	(9)	(9)	(8)
Deferred income taxes and investment tax credits, net	77	43	37
Pensions and OPEB mark-to-market adjustment	43	24	26
Accrued compensation and retirement benefits	(37)	(45)	(36)
Cash collateral, net	(6)	2	6
Pension trust contributions	(27)	—	(103)
Asset retirement obligation settlements	(2)	(10)	—
Decrease (increase) in operating assets-			
Receivables	43	27	140
Prepayments and other current assets	(11)	14	(10)
Increase (decrease) in operating liabilities-			
Accounts payable	(5)	(21)	(15)
Accrued taxes	10	(3)	(9)
Other	—	(4)	23
Net cash provided from operating activities	327	327	356
CASH FLOWS FROM FINANCING ACTIVITIES:			
New financing-			
Long-term debt	—	—	100
Short-term borrowings, net	—	49	92
Redemptions and repayments-			
Long-term debt	—	(10)	(102)
Short-term borrowings, net	(142)	—	—
Common stock dividend payments	(268)	(250)	(420)
Other	(5)	(2)	(2)
Net cash used for financing activities	(415)	(213)	(332)
CASH FLOWS FROM INVESTING ACTIVITIES:			
Property additions	(149)	(150)	(153)
Leasehold improvement payments from affiliated companies	—	18	—
Sales of investment securities held in trusts	154	83	131
Purchases of investment securities held in trusts	(161)	(89)	(139)
Loans to affiliated companies, net	(164)	102	102
Collection of principal on long-term notes receivable	—	—	196
Cash investments	27	25	20
Other	(13)	(7)	(3)
Net cash provided from (used for) investing activities	(306)	(18)	154
Net change in cash and cash equivalents	(394)	96	178

Cash and cash equivalents at beginning of year	420	324	146
Cash and cash equivalents at end of year	26	$420	$324
SUPPLEMENTAL CASH FLOW INFORMATION:			
Cash paid (received) during the year-			
Interest (net of amounts capitalized)	$82	$83	$87
Income taxes	$(69)	$76	$21

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

	For the Years Ended December 31,		
(In thousands)	2011	2010	2009
STATEMENTS OF INCOME			
REVENUES (Note 17):			
Electric sales	$808,778	$1,152,950	$1,609,946
Excise tax collections	68,009	68,422	66,192
Total revenues	876,787	1,221,372	1,676,138
OPERATING EXPENSES (Note 17):			
Purchased power from affiliates	143,030	361,317	734,592
Purchased power from non-affiliates	93,242	129,054	245,809
Other operating expenses	129,716	115,066	148,567
Pensions and OPEB mark-to-market adjustment	20,069	11,945	38,329
Provision for depreciation	76,135	74,907	73,883
Amortization of regulatory assets, net	52,846	169,541	236,380
General taxes	154,487	143,294	145,324
Total operating expenses	669,525	1,005,124	1,622,884
OPERATING INCOME	207,262	216,248	53,254
OTHER INCOME (EXPENSE) (Note 17):			
Investment income	23,565	27,360	31,194
Miscellaneous income	3,959	2,362	3,911
Interest expense	(129,679)	(133,351)	(137,171)
Capitalized interest	608	63	261
Total other expense	(101,547)	(103,566)	(101,805)
INCOME (LOSS) BEFORE INCOME TAXES	105,715	112,682	(48,551)
INCOME TAXES	33,852	35,127	(19,794)
NET INCOME (LOSS)	71,863	77,555	(28,757)
Income attributable to noncontrolling interest	1,293	1,517	1,714
EARNINGS AVAILABLE (LOSSES APPLICABLE) TO PARENT	$70,570	$76,038	$(30,471)
STATEMENTS OF COMPREHENSIVE INCOME			
NET INCOME (LOSS)	$71,863	$77,555	$(28,757)
OTHER COMPREHENSIVE INCOME (LOSS):			
Pensions and OPEB prior service costs	(13,689)	(40,442)	46,188
Income taxes (benefits) on other comprehensive income	(6,842)	(14,732)	19,297
Other comprehensive income (loss), net of tax	(6,847)	(25,710)	26,891

COMPREHENSIVE INCOME (LOSS)	65,016	51,845	(1,866)
Comprehensive income attributable to noncontrolling interest	1,293	1,517	1,714
COMPREHENSIVE INCOME AVAILABLE (LOSSES APPLICABLE) TO PARENT	$63,723	$50,328	$(3,580)

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

THE CLEVELAND ELECTRIC ILLUMINATING COMPANY
CONSOLIDATED BALANCE SHEETS

	As of December 31,	
(In thousands, except share amounts)	2011	2010
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$244	$238
Receivables-		
Customers, net of allowance for uncollectible accounts of $2,933 in 2011 and $4,589 in 2010	91,967	183,744
Affiliated companies	15,139	77,047
Other	13,036	11,544
Notes receivable from affiliated companies	123,712	23,236
Prepayments and other	12,552	3,656
	256,650	299,465
UTILITY PLANT:		
In service	2,555,617	2,460,117
Less — Accumulated provision for depreciation	974,229	944,617
	1,581,388	1,515,500
Construction work in progress	33,986	38,610
	1,615,374	1,554,110
OTHER PROPERTY AND INVESTMENTS:		
Investment in lessor notes	286,812	340,029
Other	10,024	10,074
	296,836	350,103
DEFERRED CHARGES AND OTHER ASSETS:		
Goodwill	1,688,521	1,688,521
Regulatory assets	295,284	369,829
Other	98,928	92,100
	2,082,733	2,150,450
	$4,251,593	$4,354,128
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Currently payable long-term debt	$743	$161
Short-term borrowings from affiliated companies	23,303	105,996
Accounts payable-		
Affiliated companies	31,786	32,020
Other	8,548	14,947
Accrued taxes	86,440	85,346
Accrued interest	18,549	18,555
Other	34,124	44,569
	203,493	301,594
CAPITALIZATION:		
Common stockholder’s equity		
Common stock, without par value, authorized 105,000,000 shares - 67,930,743 shares outstanding	865,570	863,372
Accumulated other comprehensive income	27,264	34,111
Retained earnings	388,246	381,676
Common stockholder’s equity	1,281,080	1,279,159

Noncontrolling interest	15,195	18,017
Total equity	1,296,275	1,297,176
Long-term debt and other long-term obligations	1,834,890	1,852,530
	3,131,165	3,149,706
NONCURRENT LIABILITIES:		
Accumulated deferred income taxes	662,805	647,292
Accumulated deferred investment tax credits	10,153	10,994
Retirement benefits	86,619	95,654
Other	157,358	148,888
	916,935	902,828
COMMITMENTS AND CONTINGENCIES (Note 6 and 16)		
	$4,251,593	$4,354,128

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

THE CLEVELAND ELECTRIC ILLUMINATING COMPANY
CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDER'S EQUITY

(In thousands, except share amounts)	Common Stock Number of Shares	Common Stock Carrying Value	Accumulated Other Comprehensive Income	Retained Earnings
Balance, January 1, 2009	67,930,743	$855,070	$32,930	$686,109
Losses applicable to parent				(30,471)
Pensions and OPEB, net of $19,297 of income taxes (Note 3)			26,891	
Restricted stock units		74		
Consolidated tax benefit allocation		6,038		
Cash dividends declared on common stock				(250,000)
Balance, December 31, 2009	67,930,743	861,182	59,821	405,638
Earnings available to parent				76,038
Pensions and OPEB, net of $14,732 of income tax benefit (Note 3)			(25,710)	
Restricted stock units		55		
Consolidated tax benefit allocation		2,135		
Cash dividends declared on common stock				(100,000)
Balance, December 31, 2010	67,930,743	863,372	34,111	381,676
Earnings available to parent				70,570
Pensions and OPEB, net of $6,842 of income tax benefits (Note 3)			(6,847)	
Restricted stock units		(30)		
Consolidated tax benefit allocation		2,228		
Cash dividends declared on common stock				(64,000)
Balance, December 31, 2011	67,930,743	$865,570	$27,264	$388,246

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

THE CLEVELAND ELECTRIC ILLUMINATING COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS

	For the Years Ended December 31,		
(In thousands)	2011	2010	2009
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss)	$71,863	$77,555	$(28,757)
Adjustments to reconcile net income (loss) to net cash from operating activities-			
Provision for depreciation	76,135	74,907	73,883
Amortization of regulatory assets, net	52,846	169,541	236,380
Deferred income taxes and investment tax credits, net	23,931	(23,614)	(61,450)
Pensions and OPEB mark-to-market adjustment	20,069	11,945	38,329
Accrued compensation and retirement benefits	(11,951)	(2,228)	(4,326)
Electric service prepayment programs	—	—	(3,510)
Cash collateral, net	(5,016)	889	5,440
Lease assignment payments to affiliated company	—	—	(40,827)
Pension trust contributions	(35,000)	—	(89,789)
Uncertain tax positions	46	(2,872)	10,766
Decrease (increase) in operating assets-			
Receivables	164,848	60,762	65,603
Prepayments and other current assets	(8,896)	6,075	(7,186)
Increase (decrease) in operating liabilities-			
Accounts payable	(19,277)	(38,833)	(3,479)
Accrued taxes	1,094	(3,700)	2,533
Accrued interest	(7)	89	4,534
Other	(1,796)	2,109	8,732
Net cash provided from operating activities	328,889	332,625	206,876
CASH FLOWS FROM FINANCING ACTIVITIES:			
New financing-			
Long-term debt	—	—	298,398
Short-term borrowings, net	—	—	93,577
Redemptions and repayments-			
Long-term debt	(177)	(117)	(151,273)
Short-term borrowings, net	(104,228)	(254,048)	—
Common stock dividend payments	(64,000)	(100,000)	(275,000)
Other	(5,879)	(4,100)	(6,427)
Net cash used for financing activities	(174,284)	(358,265)	(40,725)
CASH FLOWS FROM INVESTING ACTIVITIES:			
Property additions	(96,504)	(105,660)	(103,243)
Loans to affiliated companies, net	(100,476)	3,566	(7,741)
Investment in lessor notes	53,217	48,612	37,074
Other	(10,836)	(6,870)	(6,237)
Net cash used for investing activities	(154,599)	(60,352)	(80,147)
Net change in cash and cash equivalents	6	(85,992)	86,004
Cash and cash equivalents at beginning of year	238	86,230	226
Cash and cash equivalents at end of year	$244	$238	$86,230

SUPPLEMENTAL CASH FLOW INFORMATION:			
Cash paid (received) during the year-			
Interest (net of amounts capitalized)	$127,268	$131,546	$130,689
Income taxes	$(40,551)	$67,651	$29,358

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

THE TOLEDO EDISON COMPANY
CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME

	For the Years Ended December 31,		
(In thousands)	2011	2010	2009
STATEMENTS OF INCOME			
REVENUES (Note 17):			
Electric sales	$448,988	$489,310	$810,069
Excise tax collections	27,983	27,387	23,839
Total revenues	476,971	516,697	833,908
OPERATING EXPENSES (Note 17):			
Purchased power from affiliates	94,351	180,523	392,825
Purchased power from non-affiliates	74,022	64,174	136,210
Other operating expenses	133,366	101,895	135,938
Pensions and OPEB mark-to-market adjustment	10,560	4,183	14,360
Provision for depreciation	32,467	32,161	31,181
Amortization (deferral) of regulatory assets, net	(1,679)	(1,427)	37,820
General taxes	53,911	52,045	47,815
Total operating expenses	396,998	433,554	796,149
OPERATING INCOME	79,973	83,143	37,759
OTHER INCOME (EXPENSE) (Note 17):			
Investment income	11,054	14,727	24,388
Miscellaneous expense	(366)	(4,287)	(2,169)
Interest expense	(41,876)	(41,883)	(36,512)
Capitalized interest	547	304	283
Total other expense	(30,641)	(31,139)	(14,010)
INCOME BEFORE INCOME TAXES	49,332	52,004	23,749
INCOME TAXES	14,605	15,756	5,347
NET INCOME	34,727	36,248	18,402
Income attributable to noncontrolling interest	7	4	21
EARNINGS AVAILABLE TO PARENT	$34,720	$36,244	$18,381
STATEMENTS OF COMPREHENSIVE INCOME			
NET INCOME	$34,727	$36,248	$18,402
OTHER COMPREHENSIVE LOSS:			
Pensions and OPEB prior service costs	(5,810)	(6,950)	9,078
Change in unrealized gain on available-for-sale securities	4,506	131	(15,181)
Other comprehensive loss	(1,304)	(6,819)	(6,103)
Income tax benefits on other comprehensive loss	(1,296)	(1,421)	(533)
Other comprehensive loss, net of tax	(8)	(5,398)	(5,570)

COMPREHENSIVE INCOME	34,719	30,850	12,832
Comprehensive income attributable to noncontrolling interest	7	4	21
COMPREHENSIVE INCOME AVAILABLE TO PARENT	$34,712	$30,846	$12,811

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

THE TOLEDO EDISON COMPANY
CONSOLIDATED BALANCE SHEETS

	As of December 31,	
(In thousands, except share amounts)	2011	2010
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$12	$149,262
Receivables-		
Customers, net of allowance for uncollectible accounts of $1,467 in 2011 and $1 in 2010	49,014	29
Affiliated companies	30,925	31,777
Other, net of allowance for uncollectible accounts of $264 in 2011 and $330 in 2010	2,670	18,464
Notes receivable from affiliated companies	187,086	96,765
Prepayments and other	7,925	2,306
	277,632	298,603
UTILITY PLANT:		
In service	999,146	962,428
Less — Accumulated provision for depreciation	464,204	450,531
	534,942	511,897
Construction work in progress	11,513	12,604
	546,455	524,501
OTHER PROPERTY AND INVESTMENTS:		
Investment in lessor notes (Note 6)	82,153	103,872
Nuclear plant decommissioning trusts	83,125	75,558
Other	1,442	1,492
	166,720	180,922
DEFERRED CHARGES AND OTHER ASSETS:		
Goodwill	500,576	500,576
Regulatory assets	70,235	72,588
Other	60,895	48,740
	631,706	621,904
	$1,622,513	$1,625,930
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Currently payable long-term debt	$193	$199
Accounts payable-		
Affiliated companies	22,424	17,168
Other	8,847	7,351
Accrued taxes	34,850	24,623
Lease market valuation liability	36,900	36,900
Other	30,753	29,075
	133,967	115,316
CAPITALIZATION:		
Common stockholder’s equity -		
Common stock, without par value, authorized 60,000,000 shares - 29,402,054 shares outstanding	147,010	147,010
Other paid-in capital	163,013	163,021
Accumulated other comprehensive income	15,078	15,086

Retained earnings	43,220	42,500
Total common stockholder's equity	368,321	367,617
Noncontrolling interest	2,596	2,589
Total equity	370,917	370,206
Long-term debt and other long-term obligations	598,869	600,493
	969,786	970,699
NONCURRENT LIABILITIES:		
Accumulated deferred income taxes	170,385	140,715
Accumulated deferred investment tax credits	5,499	5,930
Retirement benefits	50,537	71,486
Asset retirement obligations	30,745	28,762
Lease market valuation liability (Note 6)	162,400	199,300
Other	99,194	93,722
	518,760	539,915
COMMITMENTS AND CONTINGENCIES (Notes 6 and 16)		
	$1,622,513	$1,625,930

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

THE TOLEDO EDISON COMPANY
CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDER'S EQUITY

(In thousands, except share amounts)	Common Stock Number of Shares	Common Stock Par Value	Other Paid-In Capital	Accumulated Other Comprehensive Income	Retained Earnings
Balance, January 1, 2009	29,402,054	$147,010	$160,718	$26,054	$117,875
Earnings available to parent					18,381
Change in unrealized gain on investments, net of $5,756 of income taxes				(9,425)	
Pensions and OPEB, net of $5,223 of income tax benefits (Note 3)				3,855	
Restricted stock units			71		
Consolidated tax benefit allocation			2,231		
Balance, December 31, 2009	29,402,054	147,010	163,020	20,484	136,256
Earnings available to parent					36,244
Change in unrealized gain on investments, net of $46 of income tax benefits				85	
Pensions and OPEB, net of $1,467 of income tax benefits (Note 3)				(5,483)	
Restricted stock units			1		
Cash dividends declared on common stock					(130,000)
Balance, December 31, 2010	29,402,054	147,010	163,021	15,086	42,500
Earnings available to parent					34,720
Change in unrealized gain on investments, net of $1,610 of income taxes				2,896	
Pensions and OPEB, net of $2,906 of income tax benefits (Note 3)				(2,904)	
Restricted stock units			(8)		
Cash dividends declared on common stock					(34,000)
Balance, December 31, 2010	29,402,054	$147,010	$163,013	$15,078	$43,220

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

THE TOLEDO EDISON COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS

	For the Years Ended December 31,		
(In thousands)	2011	2010	2009
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	$34,727	$36,248	$18,402
Adjustments to reconcile net income to net cash from operating activities-			
Provision for depreciation	32,467	32,161	31,181
Amortization (deferral) of regulatory assets, net	(1,679)	(1,427)	37,820
Deferred rents and lease market valuation liability	(37,839)	(37,839)	(37,839)
Deferred income taxes and investment tax credits, net	35,739	26,152	(589)
Pensions and OPEB mark-to-market adjustment	10,560	4,183	14,360
Accrued compensation and retirement benefits	(4,640)	(660)	(2,776)
Electric service prepayment programs	—	—	(1,458)
Pension trust contributions	(45,000)	—	(21,590)
Cash collateral, net	(2,583)	1,548	2,794
Lease assignment payment to affiliated company	—	—	(30,529)
Gain on sales of investment securities held in trusts	(2,337)	(2,348)	(7,130)
Uncertain tax positions	10	(1,831)	3,038
Decrease (increase) in operating assets-			
Receivables	(31,322)	82,369	(18,872)
Prepayments and other current assets	(5,807)	6,464	(5,898)
Increase (decrease) in operating liabilities-			
Accounts payable	264	(60,183)	35,192
Accrued taxes	10,228	(1,333)	(1,932)
Other	6,451	(7,554)	6,754
Net cash provided from operating activities	(761)	75,950	20,928
CASH FLOWS FROM FINANCING ACTIVITIES:			
New financing-			
Long-term debt	—	—	297,422
Short-term borrowings, net	—	—	114,733
Redemptions and repayments-			
Long-term debt	(139)	(222)	(347)
Short-term borrowings, net	—	(225,975)	—
Common stock dividend payments	(34,000)	(130,000)	(25,000)
Other	(1,762)	(112)	(351)
Net cash provided from (used for) financing activities	(35,901)	(356,309)	386,457
CASH FLOWS FROM INVESTING ACTIVITIES:			
Property additions	(37,324)	(42,097)	(47,028)
Leasehold improvement payments from associated companies	—	32,829	—
Loans to affiliated companies, net	(90,322)	(11,664)	63,711
Redemption of lessor notes (Note 6)	21,719	20,485	18,330
Sales of investment securities held in trusts	120,460	125,557	168,580
Purchases of investment securities held in trusts	(123,052)	(127,323)	(170,996)
Other	(4,069)	(4,878)	(3,284)
Net cash provided from (used for) investing activities	(112,588)	(7,091)	29,313

Net change in cash and cash equivalents	(149,250)	(287,450)	436,698
Cash and cash equivalents at beginning of year	149,262	436,712	14
Cash and cash equivalents at end of year	$12	$149,262	$436,712
SUPPLEMENTAL CASH FLOW INFORMATION:			
Cash paid (received) during the year-			
Interest (net of amounts capitalized)	$40,780	$41,162	$32,353
Income taxes	$(32,884)	$(13,456)	$1,350

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

	For the Years Ended December 31,		
(In millions)	2011	2010	2009
STATEMENTS OF INCOME			
REVENUES:			
Electric sales	$2,445	$2,976	$2,944
Excise tax collections	50	51	49
Total revenues	2,495	3,027	2,993
OPERATING EXPENSES (Note 17):			
Purchased power	1,382	1,736	1,783
Other operating expenses	371	323	284
Pensions and OPEB mark-to-market adjustment	60	26	37
Provision for depreciation	135	113	108
Amortization of regulatory assets, net	108	321	344
General taxes	67	65	63
Total operating expenses	2,123	2,584	2,619
OPERATING INCOME	372	443	374
OTHER INCOME (EXPENSE) (Note 17):			
Miscellaneous income	11	6	5
Interest expense	(124)	(120)	(117)
Capitalized interest	2	1	1
Total other expense	(111)	(113)	(111)
INCOME BEFORE INCOME TAXES	261	330	263
INCOME TAXES	117	147	105
NET INCOME	$144	$183	$158
STATEMENTS OF COMPREHENSIVE INCOME			
NET INCOME	$144	$183	$158
OTHER COMPREHENSIVE LOSS:			
Pensions and OPEB prior service costs	(27)	(17)	(18)
Other comprehensive loss	(27)	(17)	(18)
Income tax benefits on other comprehensive loss	(15)	(10)	(4)
Other comprehensive loss, net of tax	(12)	(7)	(14)
COMPREHENSIVE INCOME	$132	$176	$144

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

	As of December 31,	
(In millions, except share amounts)	2011	2010
ASSETS		
CURRENT ASSETS:		
Receivables-		
Customers, net of allowance for uncollectible accounts of $4 in 2011 and 2010	$235	$323
Affiliated companies	—	54
Other	17	26
Notes receivable — affiliated companies	—	177
Prepaid taxes	33	11
Other	19	13
	304	604
UTILITY PLANT:		
In service	4,872	4,783
Less — Accumulated provision for depreciation	1,743	1,682
	3,129	3,101
Construction work in progress	227	63
	3,356	3,164
OTHER PROPERTY AND INVESTMENTS:		
Nuclear fuel disposal trust	219	208
Nuclear plant decommissioning trusts	193	182
Other	2	2
	414	392
DEFERRED CHARGES AND OTHER ASSETS:		
Goodwill	1,811	1,811
Regulatory assets	408	514
Other	32	28
	2,251	2,353
	$6,325	$6,513
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Currently payable long-term debt	$34	$32
Short-term borrowings-		
Affiliated companies	259	—
Accounts payable-		
Affiliated companies	19	29
Other	101	158
Accrued compensation and benefits	41	35
Customer deposits	24	23
Accrued interest	18	18
Other	36	28
	532	323
CAPITALIZATION:		
Common stockholder’s equity -		
Common stock, $10 par value, authorized 16,000,000 shares - 13,628,447 shares outstanding	136	136
Other paid-in capital	2,011	2,509

Accumulated other comprehensive income	39	51
Retained earnings (accumulated deficit)	121	(23)
Total common stockholder’s equity	2,307	2,673
Long-term debt and other long-term obligations	1,736	1,770
	4,043	4,443
NONCURRENT LIABILITIES:		
Accumulated deferred income taxes	859	793
Power purchase contract liability	147	233
Nuclear fuel disposal costs	197	197
Retirement benefits	170	182
Asset retirement obligations	115	108
Other	262	234
	1,750	1,747
COMMITMENTS, GUARANTEES AND CONTINGENCIES (Notes 6 and 16)		
	$6,325	$6,513

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 COMMON STOCKHOLDER'S EQUITY

(In millions, except share amounts)	Common Stock: Number of Shares	Common Stock: Par Value	Other Paid-In Capital	Accumulated Other Comprehensive Income	Retained Earnings (Accumulated Deficit)
Balance, January 1, 2009	14,421,637	$144	$2,645	$72	$(72)
Net income					158
Pensions and OPEB, net of $4 of income tax benefits (Note 3)				(14)	
Cash dividends declared on common stock					(127)
Repurchase of common stock	(793,190)	(8)	(142)		
Consolidated tax benefit allocation			4		
Balance, December 31, 2009	13,628,447	136	2,507	58	(41)
Net income					183
Pensions and OPEB, net of $10 of income tax benefits (Note 3)				(7)	
Cash dividends declared on common stock					(165)
Consolidated tax benefit allocation			2		
Balance, December 31, 2010	13,628,447	136	2,509	51	(23)
Net income					144
Pensions and OPEB, net of $15 of income tax benefits (Note 3)				(12)	
Cash dividends as return of capital			(500)		
Consolidated tax benefit allocation			2		
Balance, December 31, 2011	13,628,447	$136	$2,011	$39	$121

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

	For the Years Ended December 31,		
(In millions)	2011	2010	2009
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	$144	$183	$158
Adjustments to reconcile net income to net cash from operating activities-			
Provision for depreciation	135	113	108
Amortization of regulatory assets, net	108	321	344
Deferred purchased power and other costs	(93)	(105)	(148)
Deferred income taxes and investment tax credits, net	91	31	39
Pensions and OPEB mark-to-market adjustment	60	26	37
Accrued compensation and retirement benefits	(32)	(7)	(13)
Cash collateral, net	—	(23)	—
Pension trust contributions	(105)	—	(100)
Decrease (increase) in operating assets-			
Receivables	160	(67)	43
Prepaid taxes	(22)	24	(24)
Increase (decrease) in operating liabilities-			
Accounts payable	(83)	(20)	(25)
Accrued taxes	11	12	(14)
Other	11	(11)	(3)
Net cash provided from operating activities	385	477	402
CASH FLOWS FROM FINANCING ACTIVITIES:			
New financing-			
Long-term debt	—	—	299
Short-term borrowings, net	259	—	—
Redemptions and repayments-			
Long-term debt	(32)	(31)	(29)
Short-term borrowings, net	—	—	(121)
Common stock	—	—	(150)
Common stock dividend payments	(500)	(165)	(127)
Other	(1)	—	(2)
Net cash used for financing activities	(274)	(196)	(130)
CASH FLOWS FROM INVESTING ACTIVITIES:			
Property additions	(229)	(182)	(166)
Loans to affiliated companies, net	177	(74)	(87)
Sales of investment securities held in trusts	779	411	397
Purchases of investment securities held in trusts	(796)	(428)	(413)
Cost of removal	(35)	(6)	(5)
Other	(7)	(2)	2
Net cash used for investing activities	(111)	(281)	(272)
Net change in cash and cash equivalents	—	—	—
Cash and cash equivalents at beginning of year	—	—	—
Cash and cash equivalents at end of year	$—	$—	$—

SUPPLEMENTAL CASH FLOW INFORMATION:			
Cash paid (received) during the year-			
Interest (net of amounts capitalized)	$118	$117	$109
Income taxes	$(8)	$145	$96

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

METROPOLITAN EDISON COMPANY
CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME

	For the Years Ended December 31,		
(In thousands)	2011	2010	2009
STATEMENTS OF INCOME			
REVENUES (Note 17):			
Electric sales	$1,149,030	$1,733,651	$1,611,088
Gross receipts tax collections	63,511	84,896	77,894
Total revenues	1,212,541	1,818,547	1,688,982
OPERATING EXPENSES (Note 17):			
Purchased power from affiliates	142,858	612,496	365,491
Purchased power from non-affiliates	484,128	342,988	536,054
Other operating expenses	171,236	401,016	259,135
Pensions and OPEB mark-to-market adjustment	33,493	6,993	16,044
Provision for depreciation	60,831	55,792	54,652
Amortization of regulatory assets, net	92,450	160,360	244,709
General taxes	74,364	87,829	87,799
Total operating expenses	1,059,360	1,667,474	1,563,884
OPERATING INCOME	153,181	151,073	125,098
OTHER INCOME (EXPENSE) (Note 17):			
Interest income	121	3,019	9,709
Miscellaneous income	3,606	5,901	4,107
Interest expense	(52,685)	(52,829)	(56,683)
Capitalized interest	486	653	181
Total other expense	(48,472)	(43,256)	(42,686)
INCOME BEFORE INCOME TAXES	104,709	107,817	82,412
INCOME TAXES	36,820	47,733	28,875
NET INCOME	$67,889	$60,084	$53,537
STATEMENTS OF COMPREHENSIVE INCOME			
NET INCOME	$67,889	$60,084	$53,537
OTHER COMPREHENSIVE LOSS:			
Pensions and OPEB prior service costs	(21,149)	(12,968)	567
Unrealized gain on derivative hedges	335	335	335
Other comprehensive loss	(20,814)	(12,633)	902
Income taxes (benefits) on other comprehensive income	(10,918)	(7,552)	3,070
Other comprehensive loss, net of tax	(9,896)	(5,081)	(2,168)
COMPREHENSIVE INCOME	$57,993	$55,003	$51,369

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

METROPOLITAN EDISON COMPANY
CONSOLIDATED BALANCE SHEETS

	As of December 31,	
(In thousands, except share amounts)	2011	2010
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$157	$243,220
Receivables-		
Customers, net of allowance for uncollectible accounts of $3,015 in 2011 and $3,868 in 2010	138,587	178,522
Affiliated companies	11,697	24,920
Other	17,345	13,007
Notes receivable from affiliated companies	—	11,028
Prepaid taxes	333	343
Other	2,741	2,289
	170,860	473,329
UTILITY PLANT:		
In service	2,475,890	2,393,501
Less — Accumulated provision for depreciation	887,186	862,517
	1,588,704	1,530,984
Construction work in progress	46,868	23,663
	1,635,572	1,554,647
OTHER PROPERTY AND INVESTMENTS:		
Nuclear plant decommissioning trusts	309,946	289,328
Other	865	884
	310,811	290,212
DEFERRED CHARGES AND OTHER ASSETS:		
Goodwill	416,499	416,499
Regulatory assets	328,623	295,908
Power purchase contract asset	48,868	111,562
Other	16,304	31,699
	810,294	855,668
	$2,927,537	$3,173,856
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Currently payable long-term debt	$29,020	$28,760
Short-term borrowings - affiliated companies	257,563	124,079
Accounts payable-		
Associated companies	21,092	33,942
Other	42,819	29,862
Accrued taxes	10,056	61,338
Accrued interest	15,996	16,114
Other	32,015	29,278
	408,561	323,373
CAPITALIZATION:		
Common stockholder’s equity -		
Common stock, without par value, authorized 900,000 shares - 740,905 and 859,500 shares outstanding, respectively	842,744	1,197,076
Accumulated other comprehensive income	27,528	37,424

Accumulated deficit	(63,672)	(106,561)
Total common stockholder's equity	806,600	1,127,939
Long-term debt and other long-term obligations	703,525	718,860
	1,510,125	1,846,799
NONCURRENT LIABILITIES:		
Accumulated deferred income taxes	539,511	526,467
Accumulated deferred investment tax credits	6,445	6,866
Nuclear fuel disposal costs	44,476	44,449
Asset retirement obligations	205,891	192,659
Retirement benefits	42,055	29,121
Power purchase contract liability	79,188	116,027
Other	91,285	88,095
	1,008,851	1,003,684
COMMITMENTS, GUARANTEES AND CONTINGENCIES (Note 6 and 16)		
	$2,927,537	$3,173,856

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

METROPOLITAN EDISON COMPANY
CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDER'S EQUITY

(In thousands, except share amounts)	Common Stock: Number of Shares	Common Stock: Carrying Value	Accumulated Other Comprehensive Income	Accumulated Deficit
Balance, January 1, 2009	859,500	$1,196,172	$44,673	$(190,182)
Net income				53,537
Change in unrealized loss on derivative instruments			335	
Pensions and OPEB, net of $3,070 of income taxes (Note 3)			(2,503)	
Restricted stock units		55		
Consolidated tax benefit allocation		843		
Balance, December 31, 2009	859,500	1,197,070	42,505	(136,645)
Net income				60,084
Change in unrealized loss on derivative instruments, net of $522 of income taxes			(187)	
Pensions and OPEB, net of $8,074 of income tax benefits (Note 3)			(4,894)	
Restricted stock units		6		
Cash dividends declared on common stock				(30,000)
Balance, December 31, 2010	859,500	1,197,076	37,424	(106,561)
Net income				67,889
Change in unrealized loss on derivative instruments, net of $139 of income taxes			196	
Pensions and OPEB, net of $11,057 of income tax benefits (Note 3)			(10,092)	
Restricted stock units		(51)		
Consolidated tax benefit allocation		719		
Cash dividends as return of capital		(205,000)		
Repurchase of common stock	(118,595)	(150,000)		
Cash dividends declared on common stock				(25,000)
Balance, December 31, 2011	740,905	$842,744	$27,528	$(63,672)

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

	For the Years Ended December 31,		
(In thousands)	2011	2010	2009
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	$67,889	$60,084	$53,537
Adjustments to reconcile net income to net cash from operating activities-			
Provision for depreciation	60,831	55,792	54,652
Amortization of regulatory assets, net	92,450	160,360	244,709
Deferred costs recoverable as regulatory assets	(88,041)	(62,462)	(96,304)
Deferred income taxes and investment tax credits, net	4,332	34,395	67,246
Pensions and OPEB mark-to-market adjustment	33,493	6,993	16,044
Accrued compensation and retirement benefits	(26,018)	(20,027)	(12,013)
Cash collateral, net	97	2,141	(4,580)
Pension trust contributions	(35,000)	—	(123,521)
Decrease (increase) in operating assets-			
Receivables	51,717	(424)	(32,088)
Prepayments and other current assets	(875)	14,057	(8,948)
Increase (decrease) in operating liabilities-			
Accounts payable	(3,548)	(18,598)	(2,781)
Accrued taxes	(44,217)	39,375	(5,001)
Accrued interest	(118)	(1,248)	10,607
Other	12,476	8,026	4,926
Net cash provided from operating activities	125,468	278,464	166,485
CASH FLOWS FROM FINANCING ACTIVITIES:			
New financing-			
Long-term debt	—	—	300,000
Short-term borrowings, net	133,485	124,079	—
Redemptions and repayments-			
Common Stock	(150,000)	—	—
Long-term debt	(13,697)	(100,000)	—
Short-term borrowings, net	—	—	(265,003)
Common stock dividend payments	(230,000)	(30,000)	—
Other	(1,107)	—	(2,268)
Net cash provided from (used for) financing activities	(261,319)	(5,921)	32,729
CASH FLOWS FROM INVESTING ACTIVITIES:			
Property additions	(96,934)	(107,230)	(100,201)
Sales of investment securities held in trusts	860,080	460,277	67,973
Purchases of investment securities held in trusts	(868,472)	(470,192)	(77,738)
Loans to affiliated companies, net	11,028	86,122	(85,704)
Other, net	(12,914)	1,580	(3,568)
Net cash used for investing activities	(107,212)	(29,443)	(199,238)
Net change in cash and cash equivalents	(243,063)	243,100	(24)
Cash and cash equivalents at beginning of year	243,220	120	144
Cash and cash equivalents at end of year	$157	$243,220	$120

SUPPLEMENTAL CASH FLOW INFORMATION:			
Cash paid (received) during the year-			
Interest (net of amounts capitalized)	$50,038	$49,285	$41,809
Income taxes	$79,067	$(43,227)	$(5,801)

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

PENNSYLVANIA ELECTRIC COMPANY
CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME

	For the Years Ended December 31,		
(In thousands)	2011	2010	2009
STATEMENTS OF INCOME			
REVENUES (Note 17):			
Electric sales	$1,026,342	$1,471,956	$1,385,574
Gross receipts tax collections	54,852	67,915	63,372
Total revenues	1,081,194	1,539,871	1,448,946
OPERATING EXPENSES (Note 17):			
Purchased power from affiliates	208,183	643,152	341,645
Purchased power from non-affiliates	332,279	364,647	544,490
Other operating expenses	148,298	246,966	192,761
Pensions and OPEB mark-to-market adjustment	41,127	8,279	33,983
Provision for depreciation	63,071	65,694	65,637
Amortization (deferral) of regulatory assets, net	62,730	(34,819)	56,572
General taxes	66,001	73,285	73,839
Total operating expenses	921,689	1,367,204	1,308,927
OPERATING INCOME	159,505	172,667	140,019
OTHER INCOME (EXPENSE) (Note 17):			
Miscellaneous income	2,754	5,957	3,662
Interest expense	(69,302)	(69,864)	(54,605)
Capitalized interest	214	770	230
Total other expense	(66,334)	(63,137)	(50,713)
INCOME BEFORE INCOME TAXES	93,171	109,530	89,306
INCOME TAXES	30,098	46,340	38,508
NET INCOME	$63,073	$63,190	$50,798
STATEMENTS OF COMPREHENSIVE INCOME			
NET INCOME	$63,073	$63,190	$50,798
OTHER COMPREHENSIVE LOSS:			
Pensions and OPEB prior service costs	(27,960)	(20,421)	(820)
Unrealized gain on derivative hedges	65	65	79
Change in unrealized gain on investments	—	—	(17)
Other comprehensive loss	(27,895)	(20,356)	(758)
Income taxes (benefits) on other comprehensive loss	(14,566)	(11,794)	4,831
Other comprehensive loss, net of tax	(13,329)	(8,562)	(5,589)
COMPREHENSIVE INCOME	$49,744	$54,628	$45,209

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

	As of December 31,	
(In thousands, except share amounts)	2011	2010
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$2	$5
Receivables-		
Customers, net of allowance for uncollectible accounts of $2,243 in 2011 and $3,369 in 2010	125,979	148,864
Affiliated companies	18,339	54,052
Other, net of allowance for uncollectible accounts of $2 in 2011 and $1 in 2010	21,833	11,314
Notes receivable from affiliated companies	—	14,404
Prepaid taxes	7,065	14,026
Other	2,406	1,592
	175,624	244,257
UTILITY PLANT:		
In service	2,814,374	2,714,541
Less — Accumulated provision for depreciation	982,265	955,314
	1,832,109	1,759,227
Construction work in progress	57,177	30,505
	1,889,286	1,789,732
OTHER PROPERTY AND INVESTMENTS:		
Nuclear plant decommissioning trusts	165,921	152,928
Non-utility generation trusts	95,687	80,244
Other	288	297
	261,896	233,469
DEFERRED CHARGES AND OTHER ASSETS:		
Goodwill	768,628	768,628
Regulatory assets	209,178	163,428
Other	17,025	25,033
	994,831	957,089
	$3,321,637	$3,224,547
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Currently payable long-term debt	$45,522	$45,000
Short-term borrowings - affiliated companies	57,900	101,338
Accounts payable-		
Affiliated companies	36,602	35,626
Other	29,423	41,420
Accrued taxes	9,311	6,531
Accrued interest	17,455	17,378
Other	26,045	22,541
	222,258	269,834
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	913,443	913,519

Accumulated other comprehensive income	37,053	50,382
Accumulated deficit	(97,806)	(90,879)
Total common stockholder's equity	941,242	961,574
Long-term debt and other long-term obligations	1,075,781	1,072,262
	2,017,023	2,033,836
NONCURRENT LIABILITIES:		
Accumulated deferred income taxes	498,754	437,532
Retirement benefits	262,500	187,621
Asset retirement obligations	104,865	98,132
Power purchase contract liability	123,031	116,972
Other	93,206	80,620
	1,082,356	920,877
COMMITMENTS, GUARANTEES AND CONTINGENCIES (Notes 6 and 16)		
	$3,321,637	$3,224,547

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

PENNSYLVANIA ELECTRIC COMPANY
CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDER'S EQUITY

(In thousands, except share amounts)	Common Stock Number of Shares	Common Stock Par Value	Other Paid-In Capital	Accumulated Other Comprehensive Income	Accumulated Deficit
Balance, January 1, 2009	4,427,577	$88,552	$912,441	$64,533	$(64,867)
Net income					50,798
Change in unrealized gain on investments, net of $15 of income tax benefits				(2)	
Change in unrealized loss on derivative instruments, net of $7 of income taxes				72	
Pensions and OPEB, net of $4,839 of income taxes (Note 3)				(5,659)	
Restricted stock units			65		
Consolidated tax benefit allocation			931		
Cash dividends declared on common stock					(50,000)
Balance, December 31, 2009	4,427,577	88,552	913,437	58,944	(64,069)
Net income					63,190
Change in unrealized loss on derivative instruments, net of $105 of income taxes				(40)	
Pensions and OPEB, net of $11,899 of income tax benefits (Note 3)				(8,522)	
Restricted stock units			82		
Cash dividends declared on common stock					(90,000)
Balance, December 31, 2010	4,427,577	88,552	913,519	50,382	(90,879)
Net income					63,073
Change in unrealized loss on derivative instruments, net of $27 of income tax benefits				38	
Pensions and OPEB, net of $14,593 of income tax benefits (Note 3)				(13,367)	
Restricted stock units			(76)		
Cash dividends declared on common stock					(70,000)
Balance, December 31, 2011	4,427,577	$88,552	$913,443	$37,053	$(97,806)

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

	For the Years Ended December 31,		
(In thousands)	2011	2010	2009
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	$63,073	$63,190	$50,798
Adjustments to reconcile net income to net cash from operating activities-			
Provision for depreciation	63,071	65,694	65,637
Amortization (deferral) of regulatory assets, net	62,730	(34,819)	56,572
Deferred costs recoverable as regulatory assets	(93,790)	(89,070)	(100,990)
Deferred income taxes and investment tax credits, net	71,832	139,052	55,879
Pensions and OPEB mark-to-market adjustment	41,127	8,279	33,983
Accrued compensation and retirement benefits	(21,051)	(13,442)	(12,529)
Cash collateral, net	5,110	(3,980)	—
Pension trust contribution	—	—	(60,000)
Decrease (increase) in operating assets-			
Receivables	52,348	24,687	22,891
Prepaid taxes	6,147	4,728	(2,519)
Increase (decrease) in operating liabilities-			
Accounts payable	(16,865)	(5,128)	3,114
Accrued taxes	(5,048)	(10,089)	(6,855)
Accrued interest	76	(220)	4,467
Other	14,012	4,860	3,104
Net cash provided from operating activities	242,772	153,742	113,552
CASH FLOWS FROM FINANCING ACTIVITIES:			
New financing-			
Long-term debt	25,000	25,000	498,583
Short-term borrowings, net	—	59,865	—
Redemptions and repayments-			
Long-term debt	(25,000)	(49,310)	(135,000)
Short-term borrowings, net	(43,438)	—	(239,929)
Common stock dividend payments	(70,000)	(90,000)	(85,000)
Other	(1,430)	(48)	(4,453)
Net cash provided from (used for) financing activities	(114,868)	(54,493)	34,201
CASH FLOWS FROM INVESTING ACTIVITIES:			
Property additions	(112,405)	(126,344)	(124,262)
Loans to affiliated companies, net	14,404	185	244
Sales of investment securities held in trusts	450,866	164,627	84,400
Purchases of investment securities held in trusts	(471,394)	(129,714)	(98,467)
Other	(9,378)	(8,012)	(9,677)
Net cash used for investing activities	(127,907)	(99,258)	(147,762)
Net change in cash and cash equivalents	(3)	(9)	(9)
Cash and cash equivalents at beginning of year	5	14	23
Cash and cash equivalents at end of year	$2	$5	$14

SUPPLEMENTAL CASH FLOW INFORMATION:			
Cash paid (received) during the year-			
Interest (net of amounts capitalized)	$66,516	$67,208	$48,265
Income taxes	$(49,275)	$(115,870)	$(10,775)

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

COMBINED NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

1. ORGANIZATION, BASIS OF PRESENTATION AND SIGNIFICANT ACCOUNTING POLICIES

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, TrAIL and AESC), FES and its principal subsidiaries (FGCO and NGC), and FESC. AE merged with a subsidiary of FE on February 25, 2011, with AE continuing as the surviving corporation and becoming a wholly owned subsidiary of FE (See Note 2, Merger).
FirstEnergy follows GAAP and complies 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, the VSCC and the NJBPU. The preparation of financial statements in conformity with GAAP requires management to make periodic estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses and disclosure of contingent assets and liabilities. Actual results could differ from these estimates. The reported results of operations are not indicative of results of operations for any future period. FE and its subsidiaries have evaluated events and transactions for potential recognition or disclosure through the date the financial statements were issued.
FE 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. FE and its subsidiaries consolidate a VIE when it is determined that it is the primary beneficiary (see Note 8, Variable Interest Entities). Investments in affiliates over which FE and its subsidiaries have the ability to exercise significant influence, but with respect to which they 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 and Comprehensive Income. These Notes to the Consolidated Financial Statements are combined for FirstEnergy, FES, OE, CEI, TE JCP&L, Met-Ed and Penelec.
Certain prior year amounts have been reclassified to conform to the current year presentation, and the effects of the change in accounting for pensions and OPEB costs described further below have been retrospectively applied to all periods presented. Unless otherwise indicated, defined terms used herein have the meanings set forth in the accompanying Glossary of Terms.

ACCOUNTING FOR THE EFFECTS OF REGULATION

FirstEnergy accounts for the effects of regulation through the application of regulatory accounting to its operating utilities since their rates are established by a third-party regulator with the authority to set rates that bind customers, are cost-based and can be charged to and collected from customers.
FirstEnergy records regulatory assets and liabilities that result from the regulated rate-making process that would not be recorded under GAAP for non-regulated entities. These assets and liabilities are amortized in the Consolidated Statements of Income concurrent with the recovery or refund through customer rates. FirstEnergy believes that it is probable that its regulatory assets and liabilities will be recovered and settled, respectively, through future rates. FirstEnergy and the Utilities net their regulatory assets and liabilities based on federal and state jurisdictions.

Net regulatory assets on FirstEnergy's and the Utility Registrants' Consolidated Balance Sheets are comprised of the following:

Regulatory Assets (Liabilities)	FirstEnergy	OE	CEI	TE	JCP&L	Met-Ed	Penelec
	(In millions)						
December 31, 2011							
Regulatory transition costs	$608	$—	$—	$—	$424	$105	$79
Customer receivables for future income taxes	508	42	1	2	29	129	145
Nuclear decommissioning, decontamination and spent fuel disposal costs	(210)	—	—	—	(44)	(99)	(67)
Asset removal costs	(240)	(34)	(60)	(23)	(147)	—	—
PJM transmission costs	340	(3)	(3)	(1)	—	181	63
Deferred generation costs	382	125	224	37	—	(23)	(11)
Distribution costs	267	146	73	48	—	—	—
Other	375	87	60	7	146	36	—
Net regulatory assets	$2,030	$363	$295	$70	$408	$329	$209
December 31, 2010							
Regulatory transition costs	$770	$—	$—	$—	$591	$131	$43
Customer receivables for future income taxes	328	52	2	1	30	113	130
Nuclear decommissioning, decontamination and spent fuel disposal costs	(184)	—	—	—	(31)	(92)	(61)
Asset removal costs	(237)	(24)	(47)	(19)	(147)	—	—
PJM transmission costs	183	—	—	—	—	131	52
Deferred generation costs	386	125	226	35	—	—	—
Distribution costs	426	216	155	55	—	—	—
Other	158	34	34	1	71	13	(1)
Net regulatory assets	$1,830	$403	$370	$73	$514	$296	$163

Additionally, FirstEnergy had $381 million of net regulatory liabilities as of December 31, 2011, including $366 million of net regulatory liabilities attributable to Allegheny that are primarily related to asset removal costs. Net regulatory liabilities are classified within Other Noncurrent Liabilities on the Consolidated Balance Sheets.

Regulatory assets that do not earn a current return as of December 31, 2011 totaled approximately $413 million. Regulatory assets that do not earn a return are primarily comprised of certain regulatory transition and PJM transmission costs for Met-Ed and Penelec of $182 million and $115 million, respectively, that are expected to be recovered by 2020, and certain storm damage costs and pension and OPEB costs incurred by JCP&L of $122 million that are expected to be recovered by 2026.

Transition Cost Amortization

JCP&L’s and Met-Ed’s regulatory transition costs include the deferral of above-market costs for power supplied from NUGs of $142 million for JCP&L (recovered through NGC revenues) and $105 million for Met-Ed (recovered through CTC revenues). Projected above-market NUG costs are adjusted to fair value at the end of each quarter, with a corresponding offset to regulatory assets. Recovery of the remaining regulatory transition costs is expected to continue pursuant to various regulatory proceedings in New Jersey and Pennsylvania (see Note 15, Regulatory Matters).

REVENUES AND RECEIVABLES

The Utilities' principal business is providing electric service to customers in Ohio, Pennsylvania, West Virginia, New Jersey and Maryland. The Utilities’ retail customers are metered on a cycle basis. FES' and AE Supply's principal business is supplying electric power to end-use customers through retail and wholesale arrangements, including affiliated company power sales to meet a portion of the POLR and default service requirements of the Ohio and Pennsylvania Companies and competitive retail sales to customers primarily in Ohio, Pennsylvania, Illinois, Michigan, New Jersey and Maryland.

Electric revenues are recorded based on energy delivered through the end of the calendar month. An estimate of unbilled revenues is calculated to recognize electric service provided from the last meter reading through the end of the month. This estimate includes many factors, among which are historical customer usage, load profiles, estimated weather impacts, customer shopping activity and prices in effect for each class of customer. In each accounting period, the Utilities, FES and AE Supply accrue the estimated unbilled amount receivable as revenue and reverse the related prior period estimate.

Receivables from customers include distribution and retail electric sales to residential, commercial and industrial customers for the Utilities, and retail and wholesale sales to customers for FES and AE Supply. There were no material concentration of receivables as of December 31, 2011 and 2010 with respect to any particular segment of FirstEnergy's customers. Billed and unbilled customer receivables as of December 31, 2011 and 2010 are shown below.

Customer Receivables	FirstEnergy	FES	OE	CEI	TE[1]	JCP&L	Met-Ed	Penelec
	(In millions)							
December 31, 2011								
Billed	$800	$220	$67	$40	$24	$117	$79	$72
Unbilled	725	204	96	52	25	118	60	54
Total	$1,525	$424	$163	$92	$49	$235	$139	$126
December 31, 2010								
Billed	$752	$196	$81	$95	$—	$178	$101	$82
Unbilled	640	170	96	89	—	145	78	67
Total	$1,392	$366	$177	$184	$—	$323	$179	$149

(1) During 2011, TE's accounts receivable financing arrangement with Centerior Funding Corporation was terminated.

EARNINGS PER SHARE OF COMMON STOCK

Basic earnings per share of common stock are computed using the weighted average number of 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 could result 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	2011	2010	2009
	(In millions, except per share amounts)		
Weighted average number of basic shares outstanding[1]	399	304	304
Assumed exercise of dilutive stock options and awards[2]	2	1	2
Weighted average number of diluted shares outstanding[1]	401	305	306
Earnings available to FirstEnergy Corp.	$885	$742	$872
Basic earnings per share of common stock	$2.22	$2.44	$2.87
Diluted earnings per share of common stock	$2.21	$2.42	$2.85

(1) Includes 113 million shares issued to AE shareholders for the periods subsequent to the merger date (see Note 2, Merger).

(2) The number of potentially dilutive securities not included in the calculation of diluted shares outstanding due to their antidilutive effect were not significant for the years ending December 31, 2011, 2010 or 2009.

PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment reflects original cost (net of any impairments recognized), including payroll and related costs such as taxes, employee benefits, administrative and general costs, and interest costs incurred to place the assets in service. The costs of normal maintenance, repairs and minor replacements are expensed as incurred. FirstEnergy recognizes liabilities for planned major maintenance projects as they are incurred. Property, plant and equipment balances as of December 31, 2011 and 2010 were as follows:

	December 31, 2011			December 31, 2010		
Property, Plant and Equipment	Unregulated	Regulated	Total	Unregulated	Regulated	Total
	(In millions)					
In service	$15,472	$24,650	$40,122	$12,104	$18,172	$30,276
Less - Accumulated depreciation	(4,424)	(7,415)	(11,839)	(4,255)	(7,028)	(11,283)

Net plant in service	$11,048	$17,235	$28,283	$7,849	$11,144	$18,993

FirstEnergy provides for depreciation on a straight-line basis at various rates over the estimated lives of property included in plant in service. The respective annual composite rates for FirstEnergy's subsidiaries' electric plant in 2011, 2010 and 2009 are shown in the following table:

	Annual Composite Depreciation Rate		
	2011	2010	2009
FGCO	3.1 %	4.0 %	4.6 %
NGC	3.2 %	3.1 %	3.0 %
OE	2.9 %	2.9 %	3.1 %
CEI	3.2 %	3.2 %	3.3 %
TE	3.2 %	3.3 %	3.3 %
JCP&L	2.8 %	2.4 %	2.4 %
Met-Ed	2.5 %	2.5 %	2.5 %
Penelec	2.3 %	2.5 %	2.6 %
ATSI	2.4 %	2.4 %	2.4 %
Penn	2.2 %	2.2 %	2.4 %
AE Supply	3.4 %		
MP	2.5 %		
PE	2.8 %		
WP	2.5 %		
TrAIL	2.7 %		

Jointly Owned Plants

FirstEnergy, through its subsidiary, AGC, owns an undivided 40% interest (1,109 MWs) in a 2,773 MW pumped storage, hydroelectric station in Bath County, Virginia, operated by the 60% owner, Virginia Electric and Power Company, a non-affiliated utility. Net Property, Plant and Equipment includes $468 million relating to this facility as of December 31, 2011.

Asset Retirement Obligations

FirstEnergy recognizes an ARO for the future decommissioning of its nuclear power plants and future remediation of other environmental liabilities associated with all of its long-lived assets. The ARO liability represents an estimate of the fair value of FirstEnergy's current obligation related to nuclear decommissioning and the retirement or remediation of environmental liabilities of other assets. A fair value measurement inherently involves uncertainty in the amount and timing of settlement of the liability. FirstEnergy uses an expected cash flow approach to measure the fair value of the nuclear decommissioning and environmental remediation ARO. This approach applies probability weighting to discounted future cash flow scenarios that reflect a range of possible outcomes. The scenarios consider settlement of the ARO at the expiration of the nuclear power plant's current license, settlement based on an extended license term and expected remediation dates. The fair value of an ARO is recognized in the period in which it is incurred. The associated asset retirement costs are capitalized as part of the carrying value of the long-lived asset and are depreciated over the life of the related asset.

ASSET IMPAIRMENTS

Long-lived Assets

FirstEnergy reviews long-lived assets, including regulatory assets, for impairment whenever events or changes in circumstances indicate that the carrying amount of such an asset may not be recoverable. The recoverability of the long-lived asset is measured by comparing the long-lived asset's 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 future cash flows of the long-lived asset, 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. Impairments of long-lived assets recognized for the year ended December 31, 2011, are described further in Note 11, Impairment of Long-Lived Assets.

Goodwill

In a business combination, the excess of the purchase price over the estimated fair values of the assets acquired and liabilities assumed is recognized as goodwill. Goodwill is evaluated for impairment at least annually and more frequently if indicators of impairment arise. In accordance with the accounting standards, if the fair value of a reporting unit is less than its carrying value (including goodwill), the goodwill is tested for impairment. Impairment is indicated and a loss is recognized if the implied fair value of a reporting unit's goodwill is less than the carrying value of its goodwill.

With the completion of the AE merger in the first quarter of 2011, FirstEnergy reorganized its management structure, which resulted in changes to its operating segments (see Note 19, Segment Information). FirstEnergy's goodwill from the merger of $866 million was assigned to the Competitive Energy Services segment based on expected synergies from the merger. FirstEnergy's reporting units are consistent with its operating segments, and consist of Regulated Distribution, Regulated Independent Transmission and Competitive Energy Services. Goodwill is allocated to these operating segments based on the original purchase price allocation for acquisitions within the various reporting units. As of December 31, 2011, goodwill balances for Regulated Distribution and Competitive Energy Services were $5,551 million and $890 million, respectively. No goodwill has been allocated to the Regulated Independent Transmission segment.

Annual impairment testing is conducted during the third quarter of each year and for 2011 and 2010 the analysis indicated no impairment of goodwill. For purposes of annual testing the estimated fair values of Regulated Distribution and Competitive Energy Services were determined using a discounted cash flow approach.

The discounted cash flow model of the Regulated Distribution and Competitive Energy Services segments reporting units is based on the forecasted operating cash flow for the current year, projected operating cash flows (determined using forecasted amounts as well as an estimated growth rate) and a terminal value. Discounted cash flows consist of the operating cash flows for each reporting unit less an estimate for capital expenditures. The key assumptions incorporated in the discounted cash flow approach include growth rates, projected operating income, changes in working capital, projected capital expenditures, planned funding of pension plans, anticipated funding of nuclear decommissioning trusts, expected results of future rate proceedings (applicable to Regulated Distribution segment only) and a discount rate equal to assumed long-term cost of capital. Cash flows may be adjusted to exclude certain non-recurring or unusual items. Reporting unit income was the starting point for determining operating cash flow and there were no non-recurring or unusual items excluded from the calculations of operating cash flow in any of the periods included in the determination of fair value.

This approach involves management judgment and estimates that are used in relation to changing market conditions and business environment; unanticipated changes in assumptions could have a significant effect on FirstEnergy's evaluation of goodwill. At the time FirstEnergy conducted the annual impairment testing in 2011, fair value would have to have declined in excess of 44% and 53% for the Regulated Distribution and Competitive Energy Services segments, respectively, to indicate a potential goodwill impairment. Fair value would have to have declined by more than 20% for CEI, 16% for TE, 38% for JCP&L, 62% for Met-Ed, 58% for Penelec and 62% for FES to indicate a potential goodwill impairment.

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

Goodwill	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	—	866	—	—	866
Balance as of December 31, 2011	$5,551	$890	$—	$ —	$6,441

Total goodwill recognized by FES and the Utility Registrants are as follows:

Goodwill	FES	CEI	TE	JCP&L	Met-Ed	Penelec
Balance as of December 31, 2011 and 2010	$24	$1,689	$501	$1,811	$416	$769

FirstEnergy, FES and the Utility Registrants, with the exception of Met-Ed, have no accumulated impairment charge as of December 31, 2011. Met-Ed has an accumulated impairment charge of $355 million, which was recorded in 2006.

Investments

At the end of each reporting period, FirstEnergy evaluates its investments for impairment. Investments classified as available-for-sale securities are evaluated to determine whether a decline in fair value below the cost basis is other than temporary. FirstEnergy first considers its intent and ability to hold the investment until recovery and then considers, among other factors, the duration and the extent to which the security’s fair value has been less than its cost and the near-term financial prospects of the security issuer when evaluating investments for impairment. If the decline in fair value is determined to be other than temporary, the cost basis of the investment is written down to fair value. FirstEnergy recognizes in earnings the unrealized losses on available-for-sale securities held in its nuclear decommissioning trusts since the trust arrangements, as they are currently defined, do not meet the required ability and intent to hold criteria in consideration of other-than-temporary impairment. In 2011, 2010 and 2009, FirstEnergy recognized $19 million, $33 million and $62 million, respectively, of other-than-temporary impairments. The fair values of FirstEnergy's investments are disclosed in Note 9, Fair Value Measurements.

ACCUMULATED OTHER COMPREHENSIVE INCOME

AOCI, net of tax, included on FirstEnergy's, FES' and the Utility Registrants' Consolidated Balance Sheets as of December 31, 2011 and 2010, is comprised of the following:

Accumulated Other Comprehensive Income	FirstEnergy	FES	OE	CEI	TE	JCP&L	Met-Ed	Penelec
	(In millions)							
Net liability for unfunded retirement benefits	$446	$52	$54	$27	$12	$40	$28	$37
Unrealized gain on investments	19	16	—	—	3	—	—	—
Unrealized gain (loss) on derivative hedges	(39)	8	—	—	—	(1)	—	—
Balance, December 31, 2011	$426	$76	$54	$27	$15	$39	$28	$37
Net liability for unfunded retirement benefits	$472	$55	$82	$34	$15	$52	$38	$50
Unrealized gain on investments	7	6	—	—	—	—	—	—
Unrealized gain (loss) on derivative hedges	(54)	1	—	—	—	(1)	(1)	—
Balance, December 31, 2010	$425	$62	$82	$34	$15	$51	$37	$50

OCI reclassified to net income during the three years ended December 31, 2011, 2010 and 2009 is shown in the following table.

	FirstEnergy	FES	OE	CEI	TE	JCP&L	Met-Ed	Penelec
	(In millions)							
2011								
Pensions and OPEB	$169	$18	$28	$12	$5	$25	$17	$23
Gain on investments	157	51	6	—	2	27	49	23
Loss on derivative hedges	(26)	(26)	—	—	—	—	—	—
	300	43	34	12	7	52	66	46
Income taxes related to reclassification to net income	118	16	12	4	3	21	27	19
Reclassification to net income	$182	$27	$22	$8	$4	$31	$39	$27
2010								
Pensions and OPEB	$87	$46	$23	$2	$3	$5	$8	$15
Gain on investments	54	50	2	—	2	—	—	—
Loss on derivative hedges	(35)	(24)	—	—	—	—	—	—
	106	72	25	2	5	5	8	15
Income taxes related to reclassification to net income	40	26	9	—	2	3	3	6
Reclassification to net income	$66	$46	$16	$2	$3	$2	$5	$9
2009								
Pensions and OPEB	$68	$37	$17	$2	$4	$8	$7	$12
Gain on investments	157	139	10	—	7	—	—	—
Loss on derivative hedges	(67)	(27)	—	—	—	—	—	—
	158	149	27	2	11	8	7	12

Income taxes related to reclassification to net income	60	56	10	1	4	3	3	5
Reclassification to net income	$98	$93	$17	$1	$7	$5	$4	$7

NEW ACCOUNTING PRONOUNCEMENTS

During the year, there have been various new accounting pronouncements that are not expected to have a material effect on FirstEnergy's financial statements.

CHANGE IN PENSIONS AND OPEB ACCOUNTING POLICY

Effective in 2011, FirstEnergy elected to change its method of recognizing actuarial gains and losses for its defined benefit pension and OPEB plans. Previously, FirstEnergy recognized the net actuarial gains and losses as a component of AOCI and amortized the gains and losses into income over the remaining service life of affected employees within the related plans to the extent such gains and losses were outside a corridor of the greater of 10% of the market-related value of plan assets or 10% of the plans' projected benefit obligation.

FirstEnergy has elected to immediately recognize the change in the fair value of plan assets and net actuarial gains and losses annually in the fourth quarter of each fiscal year and whenever a plan is determined to qualify for a remeasurement. The remaining components of pensions and OPEB expense, primarily service costs, interest on obligations, assumed return on assets and prior service costs, will be recorded on a quarterly basis.

While FirstEnergy's historical policy of recognizing pensions and OPEB expense was considered acceptable under GAAP, FirstEnergy believes that the new policy is preferable as it eliminates the delay in recognizing gains and losses to earnings. The change will also improve transparency to FirstEnergy's operational results and benefits plan performance by immediately recognizing deviations from expected actuarial assumptions in the year they are incurred.

This change in accounting policy has been applied retrospectively, adjusting all prior periods presented. Applying this change retrospectively increased property, plant and equipment as a result of capitalizing a portion of the pension and OPEB costs now recognized for each year in addition to additional depreciation expense. As a result of increasing those asset balances, FirstEnergy recognized additional affiliated company asset transfers associated with ATSI and the Generation Asset Transfer, and further impairments of certain long-lived assets in those periods. Additionally, the allocation of related pension and OPEB costs from FESC and AESC to FES and the Utility Registrants resulted in affiliated noncurrent liabilities as of December 31, 2011 of $331 million-FES, $80 million-OE, $56 million-CEI, $32 million-TE, $76 million-JCP&L, $40 million-Met-ED and $40 million-Penelec. The impact of this accounting policy change on the financial statements is summarized below:

FirstEnergy

CONSOLIDATED STATEMENTS OF INCOME	Year Ended December 31, 2010			Year Ended December 31, 2009		
(In millions, except per share amounts)	As Reported	Effect of Change	As Revised	As Reported	Effect of Change	As Revised
Other operating expense	$2,850	$(154)	$2,696	$2,697	$(146)	$2,551
Pensions and OPEB mark-to-market adjustment	—	190	190	—	321	321
Provision for depreciation	746	22	768	736	21	757
Impairment of long-lived assets	384	4	388	6	—	6
Capitalized interest	165	—	165	130	1	131
Income before income taxes	1,242	(62)	1,180	1,235	(195)	1,040
Income taxes	482	(20)	462	245	(61)	184
Net Income	760	(42)	718	990	(134)	856
Earnings available to FirstEnergy Corp.	784	(42)	742	1,006	(134)	872
Basic earnings per share of common stock	$2.58	$(0.14)	$2.44	$3.31	$(0.44)	$2.87
Diluted earnings per share of common stock	$2.57	$(0.15)	$2.42	$3.29	$(0.44)	$2.85

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME	Year Ended December 31, 2010			Year Ended December 31, 2009		
(In millions)	As Reported	Effect of Change	As Revised	As Reported	Effect of Change	As Revised
Net Income	$760	$(42)	$718	$990	$(134)	$856
Pension and other postretirement benefits	(258)	38	(220)	15	260	275
Income taxes (benefits) on other comprehensive income	(90)	16	(74)	27	101	128
Comprehensive income	636	(20)	616	955	25	980
Comprehensive income attributable to FirstEnergy Corp.	660	(20)	640	971	25	996

CONSOLIDATED BALANCE SHEETS	As of December 31, 2010		
(In millions)	As Reported	Effect of Change	As Revised
Property, plant & equipment - In service	$29,451	$825	$30,276
Accumulated provision for depreciation	11,180	103	11,283
Total property, plant, and equipment	18,271	722	18,993
Regulatory assets	1,826	4	1,830
Total assets	34,805	726	35,531
Accumulated other comprehensive income (loss)	(1,539)	1,964	425
Retained earnings	4,609	(1,525)	3,084
Total common stockholders' equity	8,545	439	8,984
Total equity	8,513	439	8,952
Total capitalization	21,092	439	21,531
Accrued taxes	326	6	332
Accumulated deferred income taxes	2,879	281	3,160
Total liabilities and capitalization	34,805	726	35,531

	Year Ended December 31, 2010	Year Ended December 31, 2009

CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDERS' EQUITY						
(In millions)	As Reported	Effect of Change	As Revised	As Reported	Effect of Change	As Revised
Retained Earnings-						
Beginning Balance	$4,495	$(1,483)	$3,012	$4,159	$(1,349)	$2,810
Earnings available to Parent	784	(42)	742	1,006	(134)	872
Ending Balance	4,609	(1,525)	3,084	4,495	(1,483)	3,012
Accumulated Comprehensive Income (Loss)-						
Beginning Balance	$(1,415)	$1,942	$527	$(1,380)	$1,783	$403
Pension and other postretirement benefits, net of taxes	(151)	22	(129)	(19)	159	140
Ending Balance	(1,539)	1,964	425	(1,415)	1,942	527

CONSOLIDATED STATEMENTS OF CASH FLOW	Year Ended December 31, 2010			Year Ended December 31, 2009		
(In millions)	As Reported	Effect of Change	As Revised	As Reported	Effect of Change	As Revised
Cash flows provided by operating activities:						
Net income	$760	$(42)	$718	$990	$(134)	$856
Provision for depreciation	746	22	768	736	21	757
Deferred income taxes and investment tax credits, net	470	(20)	450	384	(61)	323
Pensions and OPEB mark-to-market adjustment	—	190	190	—	321	321
Accrued compensation and retirement benefits	89	(154)	(65)	22	(146)	(124)
Impairments of long-lived assets	384	4	388	6	—	6
Other operating activities	45	—	45	30	(1)	29

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CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME	Year Ended December 31, 2010			Year Ended December 31, 2009		
(In millions)	As Reported	Effect of Change	As Revised	As Reported	Effect of Change	As Revised
Other operating expense	$1,280	$(50)	$1,230	$1,183	$(40)	$1,143
Pensions and OPEB mark-to-market adjustment	—	107	107	—	150	150
Provision for depreciation	243	3	246	259	3	262
Impairment of long-lived assets	384	4	388	6	—	6
Income before income taxes	420	(64)	356	892	(113)	779
Income taxes	151	(26)	125	315	(34)	281
Net Income	269	(38)	231	577	(79)	498
Pension and other postretirement benefits	(58)	28	(30)	14	54	68
Income taxes (benefits) on other comprehensive income	(11)	14	3	(6)	20	14
Comprehensive income	252	(24)	228	566	(45)	521

CONSOLIDATED BALANCE SHEETS	As of December 31, 2010		
(In millions)	As Reported	Effect of Change	As Revised
Property, plant & equipment - In service	$11,321	$106	$11,427
Accumulated provision for depreciation	4,024	14	4,038
Total property, plant, and equipment	7,297	92	7,389
Total assets	12,063	92	12,155
Common stock	1,490	77	1,567
Accumulated other comprehensive income (loss)	(120)	182	62
Retained earnings	2,418	(428)	1,990
Total equity	3,788	(169)	3,619
Total capitalization	6,969	(169)	6,800
Accumulated deferred income taxes	58	9	67
Other noncurrent liabilities	244	252	496
Total liabilities and capitalization	12,063	92	12,155

CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDERS' EQUITY	Year Ended December 31, 2010			Year Ended December 31, 2009		
(In millions)	As Reported	Effect of Change	As Revised	As Reported	Effect of Change	As Revised
Retained Earnings-						
Beginning Balance	2,149	(390)	1,759	1,572	(311)	1,261
Net income	269	(38)	231	577	(79)	498
Ending Balance	2,418	(428)	1,990	2,149	(390)	1,759
Accumulated Comprehensive Income (Loss)-						
Beginning Balance	(103)	168	65	(92)	134	42
Pension and other postretirement benefits, net of taxes	(36)	14	(22)	6	34	40

Ending Balance	(120)	182	62	(103)	168	65
Common Stock-						
Beginning Balance	1,468	77	1,545	1,464	77	1,541
Ending Balance	1,490	77	1,567	1,468	77	1,545

CONSOLIDATED STATEMENTS OF CASH FLOW	Year Ended December 31, 2010			Year Ended December 31, 2009		
(In millions)	As Reported	Effect of Change	As Revised	As Reported	Effect of Change	As Revised
Cash flows provided by operating activities:						
Net income	$269	$(38)	$231	$577	$(79)	$498
Provision for depreciation	243	3	246	259	3	262
Deferred income taxes and investment tax credits, net	176	(26)	150	220	(34)	186
Pensions and OPEB mark-to-market adjustment	—	107	107	—	150	150
Accrued compensation and retirement benefits	25	(50)	(25)	6	(40)	(34)
Impairments of long-lived assets	384	4	388	6	—	6

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CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME	Year Ended December 31, 2010			Year Ended December 31, 2009		
(In millions)	As Reported	Effect of Change	As Revised	As Reported	Effect of Change	As Revised
Other operating expense	$364	$(22)	$342	$461	$(22)	$439
Pensions and OPEB mark-to-market adjustment	—	24	24	—	26	26
Provision for depreciation	88	3	91	89	3	92
Income before income taxes	238	(5)	233	188	(7)	181
Income taxes	81	(3)	78	66	(4)	62
Net Income	157	(2)	155	122	(3)	119
Pension and other postretirement benefits	(27)	(4)	(31)	46	7	53
Income taxes (benefits) on other comprehensive income	(11)	2	(9)	16	3	19
Comprehensive income	141	(8)	133	143	1	144

CONSOLIDATED BALANCE SHEETS	As of December 31, 2010		
(In millions)	As Reported	Effect of Change	As Revised
Utility plant - In service	$3,137	$85	$3,222
Accumulated provision for depreciation	1,208	10	1,218
Total property, plant, and equipment	1,929	75	2,004
Regulatory assets	400	3	403
Total assets	3,686	78	3,764
Common Stock	952	(39)	913
Accumulated other comprehensive income (loss)	(179)	261	82
Retained earnings	142	(254)	(112)
Total common stockholder's equity	915	(32)	883
Total equity	921	(32)	889
Total capitalization	2,073	(32)	2,041
Accrued taxes	79	1	80
Accumulated deferred income taxes	696	41	737
Other noncurrent liabilities	197	68	265
Total liabilities and capitalization	3,686	78	3,764

CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDER'S EQUITY	Year Ended December 31, 2010			Year Ended December 31, 2009		
(In millions)	As Reported	Effect of Change	As Revised	As Reported	Effect of Change	As Revised
Retained Earnings-						
Beginning Balance	$30	$(252)	$(222)	$254	$(249)	$5
Earnings available to Parent	157	(2)	155	122	(3)	119
Ending Balance	142	(254)	(112)	30	(252)	(222)
Accumulated Comprehensive Income (Loss)-						
Beginning Balance	$(163)	$267	$104	$(184)	$263	$79

Pension and other postretirement benefits, net of taxes	(16)	(6)	(22)	26	4	30
Ending Balance	(179)	261	82	(163)	267	104
Common Stock-						
Beginning Balance	$1,155	$(39)	$1,116	$1,224	$(39)	$1,185
Ending Balance	952	(39)	913	1,155	(39)	1,116

CONSOLIDATED STATEMENTS OF CASH FLOW	Year Ended December 31, 2010			Year Ended December 31, 2009		
(In millions)	As Reported	Effect of Change	As Revised	As Reported	Effect of Change	As Revised
Cash flows provided by operating activities:						
Net income	$157	$(2)	$155	$122	$(3)	$119
Provision for depreciation	88	3	91	89	3	92
Deferred income taxes and investment tax credits, net	46	(3)	43	41	(4)	37
Pensions and OPEB mark-to-market adjustment	—	24	24	—	26	26
Accrued compensation and retirement benefits	(23)	(22)	(45)	(14)	(22)	(36)

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CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME	Year Ended December 31, 2010			Year Ended December 31, 2009		
(In thousands)	As Reported	Effect of Change	As Revised	As Reported	Effect of Change	As Revised
Other operating expense	$130,018	$(14,952)	$115,066	$161,407	$(12,840)	$148,567
Pensions and OPEB mark-to-market adjustment	—	11,945	11,945	—	38,329	38,329
Provision for depreciation	72,753	2,154	74,907	71,908	1,975	73,883
Capitalized interest	82	(19)	63	173	88	261
Income before income taxes	111,848	834	112,682	(21,175)	(27,376)	(48,551)
Income taxes	38,673	(3,546)	35,127	(10,183)	(9,611)	(19,794)
Net Income	73,175	4,380	77,555	(10,992)	(17,765)	(28,757)
Earnings available to Parent	71,658	4,380	76,038	(12,706)	(17,765)	(30,471)
Pension and other postretirement benefits	(26,955)	(13,487)	(40,442)	(1,378)	47,566	46,188
Income taxes (benefits) on other comprehensive income	(11,926)	(2,806)	(14,732)	1,923	17,374	19,297
Comprehensive income	58,146	(6,301)	51,845	(14,293)	12,427	(1,866)
Comprehensive income available to Parent	56,629	(6,301)	50,328	(16,007)	12,427	(3,580)

CONSOLIDATED BALANCE SHEETS	As of December 31, 2010		
(In thousands)	As Reported	Effect of Change	As Revised
Utility plant - In service	$2,396,893	$63,224	$2,460,117
Accumulated provision for depreciation	932,246	12,371	944,617
Total property, plant, and equipment	1,464,647	50,853	1,515,500
Regulatory assets	370,403	(574)	369,829
Total assets	4,303,849	50,279	4,354,128
Common Stock	887,087	(23,715)	863,372
Accumulated other comprehensive income (loss)	(153,187)	187,298	34,111
Retained earnings	568,906	(187,230)	381,676
Total common stockholder's equity	1,302,806	(23,647)	1,279,159
Total equity	1,320,823	(23,647)	1,297,176
Total capitalization	3,173,353	(23,647)	3,149,706
Accrued taxes	84,668	678	85,346
Accumulated deferred income taxes	622,771	24,521	647,292
Other noncurrent liabilities	100,161	48,727	148,888
Total liabilities and capitalization	4,303,849	50,279	4,354,128

CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDER'S EQUITY	Year Ended December 31, 2010			Year Ended December 31, 2009		
(In thousands)	As Reported	Effect of Change	As Revised	As Reported	Effect of Change	As Revised

Retained Earnings-						
Beginning Balance	$597,248	$(191,610)	$405,638	$859,954	$(173,845)	$686,109
Earnings available to Parent	71,658	4,380	76,038	(12,706)	(17,765)	(30,471)
Ending Balance	568,906	(187,230)	381,676	597,248	(191,610)	405,638
Accumulated Comprehensive Income (Loss)-						
Beginning Balance	$(138,158)	$197,979	$59,821	$(134,857)	$167,787	$32,930
Pension and other postretirement benefits, net of taxes	(15,029)	(10,681)	(25,710)	(3,301)	30,192	26,891
Ending Balance	(153,187)	187,298	34,111	(138,158)	197,979	59,821
Common Stock-						
Beginning Balance	$884,897	$(23,715)	$861,182	$878,785	$(23,715)	$855,070
Ending Balance	887,087	(23,715)	863,372	884,897	(23,715)	861,182

CONSOLIDATED STATEMENTS OF CASH FLOW	Year Ended December 31, 2010			Year Ended December 31, 2009		
(In thousands)	As Reported	Effect of Change	As Revised	As Reported	Effect of Change	As Revised
Cash flows provided by operating activities:						
Net income	$73,175	$4,380	$77,555	$(10,992)	$(17,765)	$(28,757)
Provision for depreciation	72,753	2,154	74,907	71,908	1,975	73,883
Deferred income taxes and investment tax credits, net	(20,068)	(3,546)	(23,614)	(51,839)	(9,611)	(61,450)
Pensions and OPEB mark-to-market adjustment	—	11,945	11,945	—	38,329	38,329
Accrued compensation and retirement benefits	12,724	(14,952)	(2,228)	8,514	(12,840)	(4,326)
Other operating activities	2,090	19	2,109	8,820	(88)	8,732

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CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME	Year Ended December 31, 2010			Year Ended December 31, 2009		
(In thousands)	As Reported	Effect of Change	As Revised	As Reported	Effect of Change	As Revised
Other operating expense	$108,072	$(6,177)	$101,895	$142,203	$(6,265)	$135,938
Pensions and OPEB mark-to-market adjustment	—	4,183	4,183	—	14,360	14,360
Provision for depreciation	31,613	548	32,161	30,727	454	31,181
Miscellaneous expense	(4,206)	(81)	(4,287)	(2,436)	267	(2,169)
Capitalized interest	358	(54)	304	169	114	283
Income before income taxes	50,693	1,311	52,004	31,917	(8,168)	23,749
Income taxes	17,645	(1,889)	15,756	7,939	(2,592)	5,347
Net Income	33,048	3,200	36,248	23,978	(5,576)	18,402
Earnings available to Parent	33,044	3,200	36,244	23,957	(5,576)	18,381
Pension and other postretirement benefits	(655)	(6,295)	(6,950)	(7,880)	16,958	9,078
Income taxes (benefits) on other comprehensive income	(1,144)	(277)	(1,421)	(6,630)	6,097	(533)
Comprehensive income	33,668	(2,818)	30,850	7,547	5,285	12,832
Comprehensive income available to Parent	33,664	(2,818)	30,846	7,526	5,285	12,811

CONSOLIDATED BALANCE SHEETS	As of December 31, 2010		
(In thousands)	As Reported	Effect of Change	As Revised
Utility plant - In service	$947,203	$15,225	$962,428
Accumulated provision for depreciation	446,401	4,130	450,531
Total property, plant, and equipment	500,802	11,095	511,897
Regulatory assets	72,059	529	72,588
Total assets	1,614,306	11,624	1,625,930
Other Paid-In Capital	178,182	(15,161)	163,021
Accumulated other comprehensive income (loss)	(49,183)	64,269	15,086
Retained earnings	117,534	(75,034)	42,500
Total common stockholder's equity	393,543	(25,926)	367,617
Total equity	396,132	(25,926)	370,206
Total capitalization	996,625	(25,926)	970,699
Accrued taxes	24,401	222	24,623
Accumulated deferred income taxes	132,019	8,696	140,715
Other noncurrent liabilities	65,090	28,632	93,722
Total liabilities and capitalization	1,614,306	11,624	1,625,930

CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDER'S EQUITY	Year Ended December 31, 2010			Year Ended December 31, 2009		
(In thousands)	As Reported	Effect of Change	As Revised	As Reported	Effect of Change	As Revised
Retained Earnings-						
Beginning Balance	$214,490	$(78,234)	$136,256	$190,533	$(72,658)	$117,875
Earnings available to Parent	33,044	3,200	36,244	23,957	(5,576)	18,381

Ending Balance	117,534	(75,034)	42,500	214,490	(78,234)	136,256
Accumulated Comprehensive Income (Loss)-						
Beginning Balance	$(49,803)	$70,287	$20,484	$(33,372)	$59,426	$26,054
Pension and other postretirement benefits, net of taxes	535	(6,018)	(5,483)	(7,006)	10,861	3,855
Ending Balance	(49,183)	64,269	15,086	(49,803)	70,287	20,484
Other Paid-In Capital-						
Beginning Balance	$178,181	$(15,161)	$163,020	$175,879	$(15,161)	$160,718
Ending Balance	178,182	(15,161)	163,021	178,181	(15,161)	163,020

CONSOLIDATED STATEMENTS OF CASH FLOW	Year Ended December 31, 2010			Year Ended December 31, 2009		
(In thousands)	As Reported	Effect of Change	As Revised	As Reported	Effect of Change	As Revised
Cash flows provided by operating activities:						
Net income	$33,048	$3,200	$36,248	$23,978	$(5,576)	$18,402
Provision for depreciation	31,613	548	32,161	30,727	454	31,181
Deferred income taxes and investment tax credits, net	28,041	(1,889)	26,152	2,003	(2,592)	(589)
Pensions and OPEB mark-to-market adjustment	—	4,183	4,183	—	14,360	14,360
Accrued compensation and retirement benefits	5,517	(6,177)	(660)	3,489	(6,265)	(2,776)
Other operating activities	(7,689)	135	(7,554)	7,135	(381)	6,754

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CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME	Year Ended December 31, 2010			Year Ended December 31, 2009		
(In millions)	As Reported	Effect of Change	As Revised	As Reported	Effect of Change	As Revised
Other operating expense	$344	$(21)	$323	$310	$(26)	$284
Pensions and OPEB mark-to-market adjustment	—	26	26	—	37	37
Provision for depreciation	108	5	113	103	5	108
Income before income taxes	340	(10)	330	279	(16)	263
Income taxes	148	(1)	147	109	(4)	105
Net Income	192	(9)	183	170	(12)	158
Pension and other postretirement benefits	(19)	2	(17)	(40)	22	(18)
Income taxes (benefits) on other comprehensive income	(9)	(1)	(10)	(14)	10	(4)
Comprehensive income	182	(6)	176	144	—	144

CONSOLIDATED BALANCE SHEETS	As of December 31, 2010		
(In millions)	As Reported	Effect of Change	As Revised
Utility plant - In service	$4,563	$220	$4,783
Accumulated provision for depreciation	1,657	25	1,682
Total property, plant, and equipment	2,906	195	3,101
Regulatory assets	513	1	514
Total assets	6,317	196	6,513
Accumulated other comprehensive income (loss)	(253)	304	51
Retained earnings	227	(250)	(23)
Total common stockholder's equity	2,619	54	2,673
Total capitalization	4,389	54	4,443
Other	26	2	28
Accumulated deferred income taxes	716	77	793
Other noncurrent liabilities	171	63	234
Total liabilities and capitalization	6,317	196	6,513

CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDER'S EQUITY	Year Ended December 31, 2010			Year Ended December 31, 2009		
(In millions)	As Reported	Effect of Change	As Revised	As Reported	Effect of Change	As Revised
Retained Earnings-						
Beginning Balance	$200	$(241)	$(41)	$157	$(229)	$(72)
Net Income	192	(9)	183	170	(12)	158
Ending Balance	227	(250)	(23)	200	(241)	(41)
Accumulated Comprehensive Income (Loss)-						
Beginning Balance	$(243)	$301	$58	$(217)	$289	$72
Pension and other postretirement benefits, net of taxes	(10)	3	(7)	(26)	12	(14)
Ending Balance	(253)	304	51	(243)	301	58

CONSOLIDATED STATEMENTS OF CASH FLOW	Year Ended December 31, 2010			Year Ended December 31, 2009		
(In millions)	As Reported	Effect of Change	As Revised	As Reported	Effect of Change	As Revised
Cash flows provided by operating activities:						
Net income	$192	$(9)	$183	$170	$(12)	$158
Provision for depreciation	108	5	113	103	5	108
Deferred income taxes and investment tax credits, net	32	(1)	31	43	(4)	39
Pensions and OPEB mark-to-market adjustment	—	26	26	—	37	37
Accrued compensation and retirement benefits	14	(21)	(7)	13	(26)	(13)

Met-Ed CONSOLIDATED STATEMENTS OF INCOME	Year Ended December 31, 2010			Year Ended December 31, 2009		
(In thousands)	As Reported	Effect of Change	As Revised	As Reported	Effect of Change	As Revised
Other operating expense	$418,569	$(17,553)	$401,016	$277,024	$(17,889)	$259,135
Pensions and OPEB mark-to-market adjustment	—	6,993	6,993	—	16,044	16,044
Provision for depreciation	52,176	3,616	55,792	51,006	3,646	54,652
Miscellaneous income	5,901	—	5,901	4,033	74	4,107
Capitalized interest	653	—	653	159	22	181
Income before income taxes	100,873	6,944	107,817	84,117	(1,705)	82,412
Income taxes	42,866	4,867	47,733	28,594	281	28,875
Net Income	58,007	2,077	60,084	55,523	(1,986)	53,537
Pension and other postretirement benefits	289	(13,257)	(12,968)	(118)	685	567
Income taxes (benefits) on other comprehensive income	(544)	(7,008)	(7,552)	2,784	286	3,070
Comprehensive income	59,175	(4,172)	55,003	52,956	(1,587)	51,369

CONSOLIDATED BALANCE SHEETS	As of December 31, 2010		
(In thousands)	As Reported	Effect of Change	As Revised
Utility plant - In service	$2,247,853	$145,648	$2,393,501
Accumulated provision for depreciation	846,003	16,514	862,517
Total property, plant, and equipment	1,401,850	129,134	1,530,984
Regulatory assets	295,856	52	295,908
Total assets	3,044,670	129,186	3,173,856
Accumulated other comprehensive income (loss)	(142,383)	179,807	37,424
Retained earnings	32,406	(138,967)	(106,561)
Total common stockholder's equity	1,087,099	40,840	1,127,939
Total capitalization	1,805,959	40,840	1,846,799
Accrued taxes	60,856	482	61,338
Accumulated deferred income taxes	473,009	53,458	526,467
Other noncurrent liabilities	53,689	34,406	88,095
Total liabilities and capitalization	3,044,670	129,186	3,173,856

CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDER'S EQUITY	Year Ended December 31, 2010			Year Ended December 31, 2009		
(In thousands)	As Reported	Effect of Change	As Revised	As Reported	Effect of Change	As Revised
Retained Earnings-						
Beginning Balance	$4,399	$(141,044)	$(136,645)	$(51,124)	$(139,058)	$(190,182)
Net income	58,007	2,077	60,084	55,523	(1,986)	53,537
Ending Balance	32,406	(138,967)	(106,561)	4,399	(141,044)	(136,645)

Accumulated Comprehensive Income (Loss)-						
Beginning Balance	$(143,551)	$186,056	$42,505	$(140,984)	$185,657	$44,673
Pension and other postretirement benefits, net of taxes	1,355	(6,249)	(4,894)	(2,902)	399	(2,503)
Ending Balance	(142,383)	179,807	37,424	(143,551)	186,056	42,505

CONSOLIDATED STATEMENTS OF CASH FLOW	Year Ended December 31, 2010			Year Ended December 31, 2009		
(In thousands)	As Reported	Effect of Change	As Revised	As Reported	Effect of Change	As Revised
Cash flows provided by operating activities:						
Net income	$58,007	$2,077	$60,084	$55,523	$(1,986)	$53,537
Provision for depreciation	52,176	3,616	55,792	51,006	3,646	54,652
Deferred income taxes and investment tax credits, net	29,528	4,867	34,395	66,965	281	67,246
Pensions and OPEB mark-to-market adjustment	—	6,993	6,993	—	16,044	16,044
Accrued compensation and retirement benefits	(2,474)	(17,553)	(20,027)	5,876	(17,889)	(12,013)
Other operating activities	8,026	—	8,026	5,022	(96)	4,926

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CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME	Year Ended December 31, 2010			Year Ended December 31, 2009		
(In thousands)	As Reported	Effect of Change	As Revised	As Reported	Effect of Change	As Revised
Other operating expense	$268,614	$(21,648)	$246,966	$209,156	$(16,395)	$192,761
Pensions and OPEB mark-to-market adjustment	—	8,279	8,279	—	33,983	33,983
Provision for depreciation	61,141	4,553	65,694	61,317	4,320	65,637
Miscellaneous income	5,928	29	5,957	3,662	—	3,662
Capitalized interest	750	20	770	98	132	230
Income before income taxes	100,665	8,865	109,530	111,082	(21,776)	89,306
Income taxes	41,173	5,167	46,340	45,694	(7,186)	38,508
Net Income	59,492	3,698	63,190	65,388	(14,590)	50,798
Pension and other postretirement benefits	(5,749)	(14,672)	(20,421)	(51,421)	50,601	(820)
Income taxes (benefits) on other comprehensive income	(4,262)	(7,532)	(11,794)	(17,252)	22,083	4,831
Comprehensive income	58,070	(3,442)	54,628	31,281	13,928	45,209

CONSOLIDATED BALANCE SHEETS	As of December 31, 2010		
(In thousands)	As Reported	Effect of Change	As Revised
Utility plant - In service	$2,532,629	$181,912	$2,714,541
Accumulated provision for depreciation	935,259	20,055	955,314
Total property, plant, and equipment	1,597,370	161,857	1,759,227
Regulatory assets	163,407	21	163,428
Total assets	3,062,669	161,878	3,224,547
Accumulated other comprehensive income (loss)	(163,526)	213,908	50,382
Retained earnings	60,993	(151,872)	(90,879)
Total common stockholder's equity	899,538	62,036	961,574
Total capitalization	1,971,800	62,036	2,033,836
Accrued taxes	5,075	1,456	6,531
Accumulated deferred income taxes	371,877	65,655	437,532
Other noncurrent liabilities	47,889	32,731	80,620
Total liabilities and capitalization	3,062,669	161,878	3,224,547

CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDER'S EQUITY	Year Ended December 31, 2010			Year Ended December 31, 2009		
(In thousands)	As Reported	Effect of Change	As Revised	As Reported	Effect of Change	As Revised
Retained Earnings-						
Beginning Balance	$91,501	$(155,570)	$(64,069)	$76,113	$(140,980)	$(64,867)
Net Income	59,492	3,698	63,190	65,388	(14,590)	50,798
Ending Balance	60,993	(151,872)	(90,879)	91,501	(155,570)	(64,069)

Accumulated Comprehensive Income (Loss)-						
Beginning Balance	$(162,104)	$221,048	$58,944	$(127,997)	$192,530	$64,533
Pension and other postretirement benefits, net of taxes	(1,382)	(7,140)	(8,522)	(34,177)	28,518	(5,659)
Ending Balance	(163,526)	213,908	50,382	(162,104)	221,048	58,944

CONSOLIDATED STATEMENTS OF CASH FLOW	Year Ended December 31, 2010			Year Ended December 31, 2009		
(In thousands)	As Reported	Effect of Change	As Revised	As Reported	Effect of Change	As Revised
Cash flows provided by operating activities:						
Net income	$59,492	$3,698	$63,190	$65,388	$(14,590)	$50,798
Provision for depreciation	61,141	4,553	65,694	61,317	4,320	65,637
Deferred income taxes and investment tax credits, net	133,885	5,167	139,052	63,065	(7,186)	55,879
Pensions and OPEB mark-to-market adjustment	—	8,279	8,279	—	33,983	33,983
Accrued compensation and retirement benefits	8,206	(21,648)	(13,442)	3,866	(16,395)	(12,529)
Other operating activities	4,909	(49)	4,860	3,236	(132)	3,104

2. MERGER

Purchase Price Allocation

On February 25, 2011, the merger between FE and AE closed. Pursuant to the terms of the Agreement and Plan of Merger among FE, 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 FE. As part of the merger, AE shareholders received 0.667 of a share of FE 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 FE equity-based awards on the same basis.

The total consideration in the merger was based on the closing price of a share of FE 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 AE common stock outstanding on February 24, 2011	170
Exchange ratio	0.667
Number of shares of FirstEnergy common stock issued	113
Closing price of FirstEnergy common stock on February 24, 2011	$38.16
Fair value of shares issued by FirstEnergy	$4,327
Fair value of replacement share-based compensation awards relating to pre-merger service	27
Total consideration transferred	$4,354

The allocation of the total consideration transferred in the merger to the assets acquired and liabilities assumed includes adjustments for the fair value of Allegheny 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 allocation of the purchase price was as follows:

(In millions)		
Current assets	$1,493	
Property, plant and equipment	9,660	
Investments	138	
Goodwill	866	
Other noncurrent assets	1,353	
Current liabilities	(718	)
Noncurrent liabilities	(3,444	)
Long-term debt and other long-term obligations	(4,994	)
	$4,354	

The allocation of purchase price in the table above reflects refinements made since the merger date in the determination of the fair values of income tax benefits, certain coal contracts and an adverse purchase power contract. This primarily resulted in an increase to property, plant and equipment, other noncurrent assets and current liabilities of approximately $4 million, $91 million and $4 million, respectively, and decreases to current assets, goodwill and noncurrent liabilities of $16 million, $86 million and $9 million, respectively. The impact of the refinements on the amortization of purchase accounting adjustments recorded during 2011 was not significant.

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 unregulated generation businesses have been assigned to the Regulated Distribution, Regulated Independent Transmission and Competitive Energy Services segments, respectively. The goodwill from the merger of $866 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.

The 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 contract 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 as the energy, NUG and gas transportation contracts, based on the present value of the above/below market cash flows attributable to the contracts. The fair value adjustments for these contracts are being amortized based on expected deliveries under each contract. See Note 7, Intangible Assets for additional information related to Intangible assets.

Acquired land easements and software with a fair value of $190 million are included in "Property, plant and equipment" on FirstEnergy's Consolidated Balance Sheet as of December 31, 2011.

In connection with the merger, FirstEnergy recorded merger transaction costs, which included change in control and other benefit payments to AE executives, of approximately $91 million ($73 million net of tax) and $65 million ($47 million net of tax) during 2011 and 2010, respectively. These costs are included in "Other operating expenses" in the Consolidated Statements of Income.

FirstEnergy also recorded approximately $93 million ($91 million net of tax) in merger integration costs during 2011, including an inventory valuation adjustment. In connection with the merger, FirstEnergy reviewed its inventory levels as a result of combining the inventory of both companies. Following this review, FirstEnergy management determined 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 period beginning on the February 25, 2011, merger date are as follows:

(In millions, except per share amounts)	February 25 - December 31, 2011
Total revenues	$3,966
Earnings Available to FirstEnergy Corp.(1)	$147

Basic Earnings Per Share	$0.37
Diluted Earnings Per Share	$0.37

(1) Includes Allegheny's after-tax merger costs of $58 million.

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Pro Forma Financial Information

The following unaudited pro forma financial information reflects the consolidated results of operations of FirstEnergy as if the merger with AE had taken place on January 1, 2010. The unaudited pro forma information was 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 merger-related costs that have been included in the pro forma earnings presented below. Combined pre-tax transaction costs incurred were approximately $91 million and $105 million in the years ended 2011 and 2010, respectively. In addition, during 2011, $93 million of pre-tax merger integration costs and $36 million of pre-tax charges from merger settlements approved by regulatory agencies were recognized.

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 had the merger been completed on January 1, 2010, or the future consolidated results of operations of the combined company.

(Pro forma amounts in millions, except per share amounts)	2011	2010
Revenues	$17,449	$18,569
Earnings available to FirstEnergy	$979	$1,183
Basic Earnings Per Share	$2.34	$2.83
Diluted Earnings Per Share	$2.33	$2.82

3. PENSIONS AND OTHER POSTEMPLOYMENT BENEFITS

As described in Note 1, Organization, Basis of Presentation and Significant Accounting Policies, FirstEnergy elected to change its method of recognizing actuarial gains and losses for its defined benefit pension plans and OPEB plans and applied this change retrospectively to all periods presented.

FirstEnergy provides a noncontributory qualified defined benefit pension plan that covers 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. In addition, FirstEnergy provides a minimum amount of noncontributory life insurance to retired employees in addition to optional contributory insurance. Health care benefits, which include certain employee contributions, deductibles and co-payments, are also available upon retirement to certain employees, their dependents and, under certain circumstances, their survivors. FirstEnergy recognizes the expected cost of providing OPEB to employees and their beneficiaries and covered dependents from the time employees are hired until they become eligible to receive those benefits. 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 2011, FirstEnergy made pre-tax contributions to its qualified pension plans of $372 million. FirstEnergy made an additional $600 million pre-tax contribution to its qualified pension plan on January 5, 2012. Pension and OPEB costs are affected by employee demographics (including age, compensation levels and employment periods), the level of contributions made to the plans and earnings on plan assets. Pension and OPEB costs may also be affected by changes in key assumptions, including anticipated rates of return on plan assets, the discount rates and health care trend rates used in determining the projected benefit obligations for pension and OPEB costs. FirstEnergy uses a December 31 measurement date for its pension and OPEB plans. The fair value of the plan assets represents the actual market value as of the measurement date.

As a result of the merger with AE, FirstEnergy assumed Allegheny's pension and OPEB plans. FirstEnergy measured the funded status of the Allegheny pension plans and OPEB plans 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 and OPEB plans as of 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 were 8.25% for Allegheny’s qualified pension plan and 5.00% for Allegheny’s OPEB plans.

Obligations and Funded Status	Pensions 2011	Pensions 2010	OPEB 2011	OPEB 2010
	(In millions)			
Change in benefit obligation:				
Benefit obligation as of January 1,	$5,858	$5,392	$861	$823
Liabilities assumed with Allegheny Merger	1,341	—	272	—
Service cost	130	99	13	10
Interest cost	374	314	48	45
Plan participants' contributions	—	—	39	30
Plan amendments	—	16	(98)	—
Special termination benefits	6	—	—	—
Medicare retiree drug subsidy	—	—	9	7
Actuarial (gain) loss	647	343	19	56
Benefits paid	(379)	(306)	(126)	(110)
Benefit obligation as of December 31,	$7,977	$5,858	$1,037	$861
Change in fair value of plan assets:				
Fair value of plan assets as of January 1,	$4,544	$4,399	$498	$467
Assets assumed with Allegheny Merger	954	—	75	—
Actual return on plan assets	364	440	23	52
Company contributions	384	11	19	59
Plan participants' contributions	—	—	39	30
Benefits paid	(379)	(306)	(126)	(110)
Fair value of plan assets as of December 31,	$5,867	$4,544	$528	$498
Funded Status:				
Qualified plan	$(1,820)	$(1,076)		
Non-qualified plans	(290)	(238)		
Funded Status	$(2,110)	$(1,314)	$(509)	$(363)
Accumulated benefit obligation	$7,409	$5,469	$—	$—
Amounts Recognized on the Balance Sheet:				
Current liabilities	$(13)	$(11)	$—	$—
Noncurrent liabilities	(2,097)	(1,303)	(509)	(363)
Net liability as of December 31,	$(2,110)	$(1,314)	$(509)	$(363)
Amounts Recognized in AOCI:				
Prior service cost (credit)	$67	$76	$(847)	$(952)
Assumptions Used to Determine Benefit Obligations (as of December 31)				
Discount rate	5.00%	5.50%	4.75%	5.00%
Rate of compensation increase	5.20%	5.20%	5.20%	5.20%
Allocation of Plan Assets (as of December 31)				
Equity securities	19%	28%	38%	47%
Bonds	48	50	44	45
Absolute return strategies	21	11	13	3

Real estate	6	6	1	2
Private equities	2	4	—	1
Cash	4	1	4	2
Total	100 %	100 %	100 %	100 %

The estimated 2012 amortization of pensions and OPEB prior service costs (credits) from AOCI into net periodic pensions and OPEB costs is approximately $12 million and $(203) million, respectively.

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Components of Net Periodic Benefit Costs	Pensions 2011	2010	2009	OPEB 2011	2010	2009
	(In millions)					
Service cost	$130	$99	$91	$13	$10	$12
Interest cost	374	314	317	48	45	64
Expected return on plan assets	(446)	(361)	(343)	(40)	(36)	(36)
Amortization of prior service cost (credit)	14	13	13	(203)	(193)	(175)
Other adjustments (settlements, curtailments, etc.)	6	—	—	—	—	—
Pensions & OPEB mark-to-market adjustment	729	264	483	36	22	16
Net periodic cost	$807	$329	$561	$(146)	$(152)	$(119)

Assumptions Used to Determine Net Periodic Benefit Cost for Years Ended December 31	Pensions 2011	2010	2009	OPEB 2011	2010	2009
Weighted-average discount rate	5.50%	6.00%	7.00%	5.00%	5.75%	7.00%
Expected long-term return on plan assets	8.25%	8.50%	9.00%	8.50%	8.50%	9.00%
Rate of compensation increase	5.20%	5.20%	5.20%	5.20%	5.20%	5.20%

The following tables set forth pension financial assets and liabilities that are accounted for at fair value by level within the fair value hierarchy. See Note 9, Fair Value Measurements, for a description of each level of the fair value hierarchy. There were no significant transfers between levels during 2011 and 2010.

	December 31, 2011 Level 1	Level 2	Level 3	Total	Asset Allocation
	(In millions)				
Cash and short-term securities	$—	$198	$—	$198	4%
Equity investments					
Domestic	223	323	—	546	9%
International	198	379	—	577	10%
Fixed income					
Government bonds	348	430	—	778	13%
Corporate bonds	—	1,998	—	1,998	34%
Distressed debt	—	—	—	—	—%
Mortgaged-backed securities (non-government)	—	48	—	48	1%
Alternatives					
Hedge funds	—	1,131	—	1,131	19%
Derivatives	—	75	70	145	2%
Private equity funds	—	—	135	135	2%
Real estate funds	—	—	327	327	6%
	$769	$4,582	$532	$5,883	100%

	December 31, 2010				Asset	
	Level 1	Level 2	Level 3	Total	Allocation	
	(In millions)					
Cash and short-term securities	$—	$72	$—	$72	1	%
Equity investments						
Domestic	342	189	—	531	12	%
International	118	615	—	733	16	%
Fixed income						
Government bonds	—	722	—	722	16	%
Corporate bonds	—	1,414	—	1,414	31	%
Distressed debt	—	97	—	97	2	%
Mortgaged-backed securities (non-government)	—	52	—	52	1	%
Alternatives						
Hedge funds	—	497	—	497	11	%
Private equity funds	—	—	119	119	4	%
Real estate funds	2	—	282	284	6	%
	$462	$3,658	$401	$4,521	100	%

The following table provides a reconciliation of changes in the fair value of pension investments classified as Level 3 in the fair value hierarchy during 2011 and 2010:

	Private Equity Funds	Real Estate Funds	Derivatives
	(In millions)		
Balance as of January 1, 2010	$137	$241	—
Actual return on plan assets:			
Unrealized gains (losses)	1	45	—
Realized gains (losses)	11	(3)	—
Purchases, sales and settlements	(28)	(1)	—
Transfers in (out)	(2)	—	—
Balance as of December 31, 2010	119	282	—
Actual return on plan assets:			
Unrealized gains	11	28	7
Realized gains (losses)	5	17	—
Purchases, sales and settlements	—	—	63
Transfers in (out)	—	—	—
Balance as of December 31, 2011	$135	$327	$70

As of December 31, 2011 and 2010, the other OPEB trust investments measured at fair value were as follows:

	December 31, 2011				Asset	
	Level 1	Level 2	Level 3	Total	Allocation	
	(In millions)					
Cash and short-term securities	$—	$19	$—	$19	4	%
Equity investment						
Domestic	164	25	—	189	35	%
International	15	3	—	18	3	%
Mutual funds	7	2	—	9	2	%
Fixed income						
U.S. treasuries	—	30	—	30	6	%
Government bonds	8	136	—	144	27	%
Corporate bonds	—	89	—	89	17	%
Distressed debt	—	—	—	—	—	%
Mortgage-backed securities (non-government)	—	5	—	5	—	%
Alternatives						
Hedge funds	—	25	—	25	5	%
Private equity funds	—	—	3	3	—	%
Real estate funds	—	—	7	7	1	%
	$194	$334	$10	$538	100	%

	December 31, 2010				Asset	
	Level 1	Level 2	Level 3	Total	Allocation	
	(In millions)					
Cash and short-term securities	$—	$16	$—	$16	2	%
Equity investment						
Domestic	178	6	—	184	36	%
International	20	19	—	39	9	%
Mutual funds	7	2	—	9	2	%
Fixed income						
U.S. treasuries	—	27	—	27	5	%
Government bonds	—	143	—	143	28	%
Corporate bonds	—	55	—	55	10	%
Distressed debt	—	3	—	3	1	%
Mortgage-backed securities (non-government)	—	4	—	4	1	%
Alternatives						
Hedge funds	—	15	—	15	3	%
Private equity funds	—	—	3	3	1	%
Real estate funds	—	—	9	9	2	%
	$205	$290	$12	$507	100	%

The following table provides a reconciliation of changes in the fair value of OPEB trust investments classified as Level 3 in the fair value hierarchy during 2011 and 2010:

	Private Equity Funds	Real Estate Funds
	(in millions)	
Balance as of January 1, 2010	$4	$7
Actual return on plan assets:		
Unrealized gains (losses)	—	—
Realized gains (losses)	—	2
Purchases, sales and settlements	(1)	—
Transfers in (out)	—	—
Balance as of December 31, 2010	3	9
Actual return on plan assets:		
Unrealized gains	—	1
Realized gains (losses)	—	—
Purchases, sales and settlements	—	—
Transfers in (out)	—	(3)
Balance as of December 31, 2011	$3	$7

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

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

FirstEnergy's target asset allocations for its pensions and OPEB trust portfolios for 2011 and 2010 are shown in the following table:

	Target Asset Allocations	
	2011	2010
Equities	23%	21%
Fixed income	50	50
Absolute return strategies	19	21
Real estate	6	6
Private equity	2	2
	100%	100%

	As of December 31,	
Assumed Health Care Cost Trend Rates	2011	2010
Health care cost trend rate assumed (pre/post-Medicare)	7.5-8.5%	8.0-9.0%
Rate to which the cost trend rate is assumed to decline (the ultimate trend rate)	5%	5%
Year that the rate reaches the ultimate trend rate (pre/post-Medicare)	2016-2018	2016-2018

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

	1-Percentage-Point Increase	1-Percentage-Point Decrease
	(in millions)	
Effect on total of service and interest cost	2	(2)
Effect on accumulated benefit obligation	20	(17)

Taking into account estimated employee future service, FirstEnergy expects to make the following benefit payments from plan assets and other payments, net of the Medicare subsidy and participant contributions:

	Pensions	OPEB
	(in millions)	
2012	$417	$111
2013	433	116
2014	461	118
2015	479	62
2016	493	63
Years 2017-2021	2,713	314

FES' and the Utility Registrants' shares of the net pensions and OPEB asset (liability) as of December 31, 2011 and 2010, were as follows:

Net Pension and OPEB Asset (Liability)	Pensions		OPEB	
	2011	2010	2011	2010
	(In millions)			
FES	$(653)	$(488)	$(11)	$(36)
OE	(4)	29	(75)	(66)
CEI	(12)	(22)	(61)	(62)
TE	11	(21)	(45)	(46)
JCP&L	(69)	(106)	(94)	(70)
Met-Ed	(6)	(6)	(31)	(19)
Penelec	(151)	(99)	(108)	(85)

FES' and the Utility Registrants' shares of the net periodic pensions and OPEB costs for the three years ended December 31, 2011, 2010 and 2009 were as follows:

Net Periodic Pension and OPEB Costs	Pensions			OPEB		
	2011	2010	2009	2011	2010	2009
	(In millions)					
FES	$168	$122	$169	$(42)	$(12)	$—
OE	63	4	38	(34)	(26)	(30)
CEI	27	10	74	(18)	(9)	(10)
TE	14	6	26	(7)	(6)	(2)
JCP&L	68	29	49	2	(10)	(3)
Met-Ed	35	12	29	(9)	(24)	(15)
Penelec	52	19	76	(7)	(24)	(14)

4. STOCK-BASED COMPENSATION PLANS

FirstEnergy has four stock-based compensation programs - LTIP, EDCP, ESOP and DCPD, as described further 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 FE common stock for each share of AE common stock.

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LTIP

The LTIP includes four forms of stock-based compensation — restricted stock, restricted stock units, stock options and performance shares.

Under the 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 pay out in common stock, with vesting periods ranging from two months to ten years. Performance share awards are currently designated to be paid in cash rather than common stock and therefore do not count against the limit on stock-based awards. As of December 31, 2011, 5.6 million shares were available for future awards.

FirstEnergy records the actual tax benefit realized from tax deductions when awards are exercised or distributed. Realized tax benefits during the years ended December 31, 2011, 2010 and 2009 were $14 million, $11 million and $9 million, respectively. The excess of the deductible amount over the recognized compensation cost is recorded as a component of stockholders' equity and reported as an other financing activity on the Consolidated Statements of Cash Flows.

Restricted Stock and Restricted Stock Units

Restricted common stock (restricted stock) and restricted stock units (stock units) activity for the year ended December 31, 2011, was as follows:

Restricted stock and stock units outstanding as of January 1, 2011	1,878,022
Granted	915,054
Converted AE restricted stock	645,197
Exercised	(984,543)
Forfeited	(100,596)
Restricted stock and stock units outstanding as of December 31, 2011	2,353,134

The 915,054 shares of restricted stock granted during the year ended December 31, 2011, had a grant-date fair value of $34 million and a weighted-average vesting period of 2.76 years.

Eligible employees receive awards of FE restricted stock or stock units subject to restrictions that lapse over a defined period of time or upon achieving performance results. Dividends are received on the restricted stock and are reinvested in additional shares. Restricted stock grants under the LTIP were as follows:

	2011	2010	2009
Restricted stock granted	297,859	71,752	73,255
Weighted average market price	$38.44	$38.43	$43.68
Weighted average vesting period (years)	2.27	4.74	4.42
Dividends restricted	Yes	Yes	Yes

Vesting activity for restricted stock during 2011 was as follows (forfeitures were not material):

Restricted Stock	Number of Shares	Weighted Average Grant-Date Fair Value
Nonvested as of January 1, 2011	475,914	$51.26
Nonvested as of December 31, 2011	654,696	$45.26
Granted in 2011	297,859	$38.44
Vested in 2011	121,573	$41.10

FirstEnergy grants two types of stock unit awards: discretionary-based and performance-based. The discretionary-based awards grant the right to receive, at the end of the period of restriction, a number of shares of common stock equal to the number of stock units set forth in each agreement. Performance-based awards grant the right to receive, at the end of the period of restriction, a number of shares of common stock equal to the number of stock units set forth in the agreement subject to adjustment based on FirstEnergy's performance relative to financial and operational performance targets.

	2011	2010	2009
Restricted stock units granted	617,195	511,418	533,399
Weighted average vesting period (years)	3.00	3.00	3.00

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Vesting activity for stock units during 2011 was as follows (forfeitures were not material):

Restricted Stock Units	Number of Shares	Weighted Average Grant-Date Fair Value
Nonvested as of January 1, 2011	1,402,108	$48.40
Nonvested as of December 31, 2011	1,566,679	$40.20
Granted in 2011	617,195	$36.80
Vested in 2011	444,818	$37.37

Compensation expense recognized in 2011, 2010 and 2009 for restricted stock and restricted stock units, net of amounts capitalized, was approximately $65 million, $22 million and $25 million, respectively.

Stock Options

Stock options were granted to eligible employees allowing them to purchase a specified number of common shares at a fixed grant price over a defined period of time. Stock option activity during 2011 was as follows:

Stock Option Activity	Number of Shares	Weighted Average Grant-Date Fair Value
Balance, January 1, 2011 (2,889,066 options exercisable)	2,889,066	$35.18
Options granted	662,122	37.75
Converted Allegheny options	1,805,811	41.75
Options exercised	(973,817)	31.48
Options forfeited	(127,197)	70.19
Balance, December 31, 2011 (3,593,863 options exercisable)	4,255,985	—$38.17

The options granted during the year ended December 31, 2011, had a grant-date fair value of $3 million and an expected weighted-average vesting period of 3.79 years.

Options outstanding and range of exercise prices as of December 31, 2011, were as follows:

	Options Outstanding and Exercisable		
Range of Exercise Prices	Shares	Weighted Average Exercise Price	Remaining Contractual Life
$20.02-$30.74	959,752	$26.88	1.50
$30.74-$40.93	2,962,802	$37.42	3.79
$42.72-$51.82	415	$44.35	2.16
$53.06-$62.97	33,215	$54.11	3.34
$64.52-$71.82	6,670	$68.44	4.99
$73.38-$80.47	291,797	$80.22	3.44
$81.19-$89.59	1,334	$81.19	5.33
Total	4,255,985	$38.17	$3.25

Compensation expense recognized for stock options during 2011 was $0.8 million. No compensation expense was recognized for stock options during 2010 and 2009. Cash received from the exercise of stock options in 2011, 2010 and 2009 was $32 million, $6 million and $7 million, respectively.

Performance Shares

Performance shares are share equivalents and do not have voting rights. The shares track the performance of FE's common stock over a three-year vesting period. During that time, dividend equivalents are converted into additional shares. The final account value may be adjusted based on the ranking of FE stock performance to a composite of peer companies. Compensation expense (credits) recognized for performance shares during 2011, 2010 and 2009, net of amounts capitalized, totaled approximately $2 million, ($4) million and $3 million, respectively. During 2011 and 2010, no cash was paid to settle performance shares due to certain criteria not being met for the previous three-year vesting period. Cash used to settle performance shares in 2009 was $15 million.

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ESOP

An ESOP Trust funded most of the matching contribution for FirstEnergy's 401(k) savings plan through December 31, 2007. All employees eligible for participation in the 401(k) savings plan are covered by the ESOP.

In 2011, 2010 and 2009, shares of FE common stock were purchased on the market and contributed to participants' accounts. Total ESOP-related compensation expenses in 2011, 2010 and 2009, net of amounts capitalized and dividends on common stock, were $55 million, $30 million and $36 million, respectively.

EDCP

Under the EDCP, covered employees can direct a portion of their compensation, including annual incentive awards and/or long-term incentive awards, into an unfunded FE stock account to receive vested stock units or into an unfunded retirement cash account. Through December 31, 2010, covered employees received an additional 20% premium in the form of stock units based on the amount allocated to the FirstEnergy stock account. During 2010, the EDCP was amended to cease the 20% stock premium with respect to annual and long-term incentive awards earned during any calendar years that commence on or after January 1, 2011. Dividends are calculated quarterly on stock units outstanding and are paid in the form of additional stock units. Upon withdrawal, stock units are converted to FE shares. Payout typically occurs three years from the date of deferral; however, an election can be made in the year prior to payout to further defer shares into a retirement stock account that will pay out in cash upon retirement (see Note 3, Pension and Other Postemployment Benefit). Interest is calculated on the cash allocated to the cash account and the total balance will pay out in cash upon retirement. Compensation expenses (credits) recognized on EDCP stock units, net of amounts capitalized, in 2011, 2010 and 2009 were $4 million, ($3) million and ($0.2) million, respectively.

DCPD

Under the DCPD, members of the Board of Directors can elect to allocate all or a portion of their cash retainers, meeting fees and chair fees to deferred stock or deferred cash accounts. Funds deferred into the stock account through December 31, 2010, received a 20% match to the funds allocated. The 20% match and any appreciation on it are forfeited if the director leaves the Board within three years from the date of deferral for any reason other than retirement, disability, death, upon a change in control or when a director is ineligible to stand for re-election. Compensation expense is recognized for the 20% match over the three-year vesting period. Directors may also elect to defer their equity retainers into the deferred stock account; however, they do not receive a 20% match on that deferral. During 2010, the DCPD was amended to cease the 20% match feature with respect to director's fees earned for service performed during any calendar years that commence on or after January 1, 2011. DCPD expenses recognized in 2011, 2010 and 2009 were $4 million, $4 million and $3 million, respectively. The net liability recognized for DCPD of approximately $6 million as of December 31, 2011, and $5 million as of December 31, 2010 and 2009, 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, 1,075,080 stock units were available for future awards as of December 31, 2011.

5. TAXES

Income Taxes

FirstEnergy records income taxes in accordance with the liability method of accounting. Deferred income taxes reflect the net tax effect of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts recognized for tax purposes. Investment tax credits, which were deferred when utilized, are being amortized over the recovery period of the related property. Deferred income tax liabilities related to temporary tax and accounting basis differences and tax credit carryforward items are recognized at the statutory income tax rates in effect when the liabilities are expected to be paid. Deferred tax assets are recognized based on income tax rates expected to be in effect when they are settled. Details of income taxes for the three years ended December 31, 2011 are shown below:

PROVISION FOR INCOME TAXES	FirstEnergy	FES	OE	CEI	TE	JCP&L	Met-Ed	Penelec
	(In millions)							
2011								
Currently payable (receivable)-								
Federal	$(243)	$(219)	$13	$17	$(15)	$19	$26	$(36)
State	19	9	(12)	(7)	(6)	7	7	(6)
	(224)	(210)	1	10	(21)	26	33	(42)
Deferred, net-								
Federal	785	206	65	15	35	71	14	75
State	24	(3)	13	10	1	20	(10)	(3)
	809	203	78	25	36	91	4	72
Investment tax credit amortization	(11)	(4)	(1)	(1)	—	—	—	—
Total provision for income taxes	$574	$(11)	$78	$34	$15	$117	$37	30
2010								
Currently payable (receivable)-								
Federal	$(23)	$(23)	$37	$58	$(8)	$80	$1	$(81)
State	35	(2)	(2)	1	(2)	36	12	(12)
	12	(25)	35	59	(10)	116	13	(93)
Deferred, net-								
Federal	432	142	41	(19)	25	30	37	122
State	27	12	3	(4)	1	1	(2)	18
	459	154	44	(23)	26	31	35	140
Investment tax credit amortization	(9)	(4)	(1)	(1)	—	—	—	(1)
Total provision for income taxes	$462	$125	$78	$35	$16	$147	$48	$46
2009								
Currently payable (receivable)-								
Federal	$(183)	$87	$21	$40	$6	$40	$(34)	$(21)
State	44	8	4	2	—	26	(4)	4
	(139)	95	25	42	6	66	(38)	(17)
Deferred, net-								
Federal	296	169	36	(62)	(3)	38	60	55
State	36	21	3	1	2	1	7	2
	332	190	39	(61)	(1)	39	67	57
Investment tax credit amortization	(9)	(4)	(2)	(1)	—	—	—	(1)
Total provision for income taxes	$184	$281	$62	$(20)	$5	$105	$29	$39

In 2011, an unregulated subsidiary of FirstEnergy elected to be taxed as a limited liability company, which improved its future taxable income and resulted in reversing a portion of its valuation allowance previously established for state income tax benefits. The reversal of the valuation allowance reduced income tax expense by $27 million.
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 currently 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 2010 of approximately $13 million and a reduction in accumulated deferred tax assets associated with these subsidies. This change reflects the anticipated increase in income taxes that will occur as a result of the change in tax law.

FES and the Utilities are party to an intercompany income tax allocation agreement with FirstEnergy and its other subsidiaries that provides for the allocation of consolidated tax liabilities. Net tax benefits attributable to FirstEnergy, excluding any tax benefits derived from interest expense associated with acquisition indebtedness from the merger with GPU, are reallocated to the subsidiaries of FirstEnergy that have taxable income. That allocation is accounted for as a capital contribution to the company receiving the tax benefit.

The following tables provide a reconciliation of federal income tax expense at the federal statutory rate to the total provision for income taxes for the three years ended December 31, 2011.

	FirstEnergy	FES	OE	CEI	TE	JCP&L	Met-Ed	Penelec
	(In millions)							
2011								
Book income (loss) before provision for income taxes	$1,459	$(70)	$206	$104	$49	$261	$105	$93
Federal income tax expense at statutory rate	$511	$(25)	$72	$36	$17	$91	$37	$33
Increases (reductions) in taxes resulting from-								
Amortization of investment tax credits	(11)	(4)	(1)	(1)	—	—	—	—
State income taxes, net of federal tax benefit	28	4	1	2	(3)	18	(2)	(6)
State unitary tax adjustments	33	—	—	—	—	—	—	—
Manufacturing deduction	16	13	3	1	—	—	—	—
Medicare Part D	36	4	6	3	1	6	5	6
Effectively settled tax items	(11)	(2)	(3)	(3)	(3)	—	—	—
State valuation allowance	(19)	2	—	—	—	—	—	(4)
Other, net	(9)	(3)	—	(4)	3	2	(3)	1
Total provision for income taxes	$574	$(11)	$78	$34	$15	$117	$37	$30
2010								
Book income before provision for income taxes	$1,204	$356	$233	$111	$52	$330	$108	$110
Federal income tax expense at statutory rate	$421	$125	$82	$39	$18	$116	$38	$39
Increases (reductions) in taxes resulting from-								
Amortization of investment tax credits	(9)	(4)	(1)	(1)	—	—	—	(1)
State income taxes, net of federal tax benefit	40	7	1	(2)	(1)	24	7	4
Manufacturing deduction	—	2	(2)	—	—	—	—	—
Medicare Part D	17	1	2	1	—	4	2	3
Effectively settled tax items	(34)	(2)	(9)	(4)	(3)	—	—	—
State valuation allowance	—	2	—	—	—	—	—	(1)
Other, net	27	(6)	5	2	2	3	1	2
Total provision for income taxes	$462	$125	$78	$35	$16	$147	$48	$46
2009								
Book income (loss) before provision for income taxes	$1,056	$779	$181	$(50)	$24	$263	$82	$89
Federal income tax expense at statutory rate	$370	$273	$63	$(18)	$8	$92	$29	$31
Increases (reductions) in taxes resulting from-								
Amortization of investment tax credits	(9)	(4)	(2)	(1)	—	—	—	(1)
	52	19	5	2	1	18	2	4

State income taxes, net of federal tax benefit								
Manufacturing deduction	(13)	(11)	(2)	1	(1)	—	—	—
Medicare Part D	14	7	(1)	—	—	2	1	2
Effectively settled tax items	(217)	—	—	—	—	—	—	—
State valuation allowance	(1)	3	—	—	—	—	—	(2)
Other, net	(12)	(6)	(1)	(4)	(3)	(7)	(3)	5
Total provision for income taxes	$184	$281	$62	$(20)	$5	$105	$29	$39

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Accumulated deferred income taxes as of December 31, 2011 and 2010 are as follows:

	FirstEnergy	FES	OE	CEI	TE	JCP&L	Met-Ed	Penelec
	(In millions)							
December 31, 2011								
Property basis differences	$6,738	$770	$673	$527	$206	$792	$457	$577
Regulatory transition charge	105	—	30	73	5	49	2	—
Customer receivables for future income taxes	125	—	—	—	—	12	55	58
Deferred MISO/PJM transmission costs	51	—	—	—	—	—	34	17
Other regulatory assets — RCP	165	—	82	55	28	—	—	—
Deferred sale and leaseback gain	(450)	(398)	(31)	—	—	(10)	(12)	—
Nonutility generation costs	36	—	—	—	—	(2)	31	7
Unamortized investment tax credits	(72)	(19)	(3)	(4)	(2)	(2)	(4)	(4)
Unrealized losses on derivative hedges	(21)	5	—	—	—	(1)	—	—
Pensions and OPEB	(752)	(85)	(76)	(36)	(18)	(75)	(24)	(114)
Lease market valuation liability	(179)	(65)	—	—	(68)	—	—	—
Oyster Creek securitization (Note 12)	93	—	—	—	—	93	—	—
Nuclear decommissioning activities	123	108	15	—	17	(7)	7	(17)
Mark-to-market adjustments	(7)	(7)	—	—	—	—	—	—
Deferred gain for asset sales — affiliated companies	—	—	31	20	7	—	—	—
Equity investments	132	—	—	—	—	—	—	—
Loss carryforwards and AMT credits	(612)	(34)	—	—	—	—	(6)	(30)
Loss carryforward valuation reserve	34	12	—	—	—	—	—	7
All other	161	(1)	66	28	(5)	10	—	(2)
Net deferred income tax liability	$5,670	$286	$787	$663	$170	$859	$540	$499
December 31, 2010								
Property basis differences	$3,910	$650	$625	$496	$206	$728	$407	$504
Regulatory transition charge	235	12	37	89	3	95	(1)	—
Customer receivables for future income taxes	113	—	—	—	—	13	48	52
Deferred MISO/PJM transmission costs	85	—	—	—	—	—	62	23
Other regulatory assets — RCP	166	—	82	56	28	—	—	—
Deferred sale and leaseback gain	(469)	(412)	(35)	—	—	(10)	(12)	—
Nonutility generation costs	51	—	—	—	—	—	55	(4)
Unamortized investment tax credits	(44)	(20)	(4)	(4)	(2)	(2)	(5)	(4)
Unrealized losses on derivative hedges	(29)	—	—	—	—	—	—	—
Pensions and OPEB	(686)	(96)	(58)	(32)	(28)	(74)	(13)	(80)

Lease market valuation liability	(197)	(82)	—	—	(81)	—	—	—
Oyster Creek securitization (Note 12)	109	—	—	—	—	109	—	—
Nuclear decommissioning activities	47	79	7	(1)	15	(8)	2	(47)
Mark-to-market adjustments	(42)	(42)	—	—	—	—	—	—
Deferred gain for asset sales — affiliated companies	—	—	34	22	7	—	—	—
Loss carryforwards	(41)	(10)	—	—	—	—	—	(23)
Loss carryforward valuation reserve	26	9	—	—	—	—	—	11
All other	(74)	(21)	49	21	(7)	(58)	(17)	6
Net deferred income tax liability	$3,160	$67	$737	$647	$141	$793	$526	$438

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 AE in 2011, FirstEnergy's unrecognized income tax benefits increased by $97 million. FirstEnergy also 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 in 2011. The IRS issued guidance in 2011 providing a safe harbor method of tax accounting for electric transmission and distribution property (see discussion below) to determine the tax treatment of repair costs for electric transmission and distribution assets. FirstEnergy is evaluating the method change for this temporary tax item and, if elected, is not expected to be material to the financial position or effective tax rates of FirstEnergy and the Utilities.

After reaching settlements on appeal in 2010 related primarily to the capitalization of certain costs for the tax years 2004-2008 and an unrelated federal tax matter related to prior year gains and losses recognized from the disposition of assets, as well as receiving final approval from the Joint Committee on Taxation for several items that were under appeal for tax years 2001-2003, FirstEnergy recognized approximately $78 million of net tax benefits in 2010, including $21 million$0 millionthat favorably affected FirstEnergy's effective tax rate. The remaining portion of the tax benefit increased FirstEnergy's accumulated deferred income taxes.

Upon reaching a settlement on several items under appeal for the tax years 2001-2003, as well as other items that effectively settled in 2009, FirstEnergy recognized approximately $100 million of net tax benefits, including $161 million that favorably affected FirstEnergy's 2009 effective tax rate. The offsetting $61 million primarily related to tax items where the uncertainty was removed and the tax refund was received.

As of December 31, 2011, it is reasonably possible that approximately $44 million of unrecognized tax benefits may be resolved during 2012, of which up to approximately $10 million, if recognized, would affect FirstEnergy's effective tax rate. The potential decrease in the amount of unrecognized tax benefits is primarily associated with issues related to the capitalization of certain costs and various state tax items.

In 2009, FirstEnergy, on behalf of the Utilities, filed a change in accounting method related to the costs to repair and maintain electric utility network (transmission and distribution) assets. In 2010, approximately $325 million of costs were included as a repair deduction on FirstEnergy's 2009 consolidated federal income tax return, which reduced taxable income and increased the amount of tax refunds that were applied to FirstEnergy's 2010 estimated federal tax payments. Due to the flow through of the Pennsylvania state income tax benefit for this change in accounting, FirstEnergy's effective tax rate was reduced by $6 million in 2010. In connection with completing FirstEnergy's 2009 consolidated tax return, FES recognized an $8 million adjustment that increased its income tax expense in 2010.

In 2008, FirstEnergy, on behalf of FGCO and NGC, filed a change in accounting method related to the costs to repair and maintain electric generation stations. During the second quarter of 2009, the IRS approved the change in accounting method and $281 million of costs were included as a repair deduction on FirstEnergy's 2008 consolidated federal income tax return. Since the IRS did not complete its review over this change in accounting method by the extended filing date of FirstEnergy's federal tax return, FirstEnergy increased the amount of unrecognized tax benefits by $34 million in the third quarter of 2009, with a corresponding adjustment to accumulated deferred income taxes for this temporary tax item. There was no impact on FirstEnergy's effective tax rate for 2009.

The following table summarizes the changes in unrecognized tax positions for the years ended 2011, 2010 and 2009.

	FirstEnergy	FES	OE	CEI	TE	JCP&L	Met-Ed	Penelec
	(In millions)							
Balance, January 1, 2009	$219	$5	$(30)	$(26)	$(4)	$42	$28	$24
Current year increases	41	34	4	3	—	—	—	—
Prior years increases	46	2	103	52	10	—	—	—
Prior years decreases	(100)	—	—	—	—	(28)	(15)	(13)
Decrease for settlement	(15)	—	—	—	—	—	—	—
Balance, December 31, 2009	$191	$41	$77	$29	$6	$14	$13	$11
Current year increases	10	6	2	(1)	—	—	2	1
Prior years increases	2	—	—	—	—	—	—	—
Prior years decreases	(81)	(4)	(19)	(15)	(6)	(21)	(2)	(5)
Decrease for settlement	(77)	(2)	(58)	(14)	—	7	(11)	(6)
Balance, December 31, 2010	$45	$41	$2	$(1)	$—	$—	$2	$1
Increase due to merger with AE	97	—	—	—	—	—	—	—
Prior years increases	10	8	—	1	—	—	—	—
Prior years decreases	(35)	(4)	(2)	—	—	—	(2)	(1)
Balance, December 31, 2011	$117	$45	$—	$—	$—	$—	$—	$—

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 federal income tax return. FirstEnergy includes net interest and penalties in the provision for income taxes. As a result of the merger with AE in 2011, the amount of accrued interest increased by $6 million. The interest associated with the 2011 settlement of the claim favorably affected FirstEnergy's effective tax rate by $7 million in 2011. The reversal of accrued interest associated with the recognized tax benefits favorably affected FirstEnergy’s effective tax rate by $12 million in 2010. The reversal of accrued interest associated with the $161 million in recognized tax benefits favorably affected FirstEnergy’s effective tax rate in 2009 by $56 million.

The following table summarizes the net interest expense (income) for the three years ended December 31, 2011 and the cumulative net interest payable (receivable) as of December 31, 2011 and 2010:

	Net Interest Expense (Income) For the Years Ended December 31,			Net Interest Payable As of December 31,	
	2011	2010	2009	2011	2010
	(In millions)			(In millions)	
FirstEnergy	$(5)	$(10)	$(49)	$11	$3
FES	1	1	(1)	4	2
OE	(2)	(3)	4	1	1
CEI	(2)	(2)	3	—	—
TE	(1)	(1)	—	—	—
JCP&L	—	(2)	(4)	—	—
Met-Ed	—	—	(2)	—	—
Penelec	—	—	(1)	—	—

FirstEnergy has tax returns that are under review at the audit or appeals level by the IRS (2008-2010) and state tax authorities. FirstEnergy's tax returns for all state jurisdictions are open from 2008-2010, as well as 2005-2007 for New Jersey. The IRS completed its audits of tax year 2008 in July 2010 and tax year 2009 in April 2011, with both tax years having one item under appeal. Tax years 2010-2011 are under review by the IRS. Allegheny is currently under audit by the IRS for tax years 2007 and 2008. Allegheny has filed its 2010 and 2009 federal returns and such filings are subject to review. State tax returns for tax years 2008 through 2010 remain subject to review in Pennsylvania, West Virginia, Maryland and Virginia for certain subsidiaries of AE. 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, results of operations, cash flow or liquidity.

FirstEnergy has recorded as deferred income tax assets the effect of net operating losses and tax credits that will more likely than not be realized through future operations and through the reversal of existing temporary differences. In 2011, the tax benefit of operating loss carryforwards included in deferred income tax expense was $344 million. As of December 31, 2011, the deferred income tax assets, before any valuation allowances, consisted of $286 million of federal net operating loss carryforwards that expire from 2024 to 2031, federal AMT credits of $25 million that have an indefinite carryforward period and $301 million of state and local net operating loss carryforwards that begin to expire in 2012.

FirstEnergy has pre-tax net operating loss carryforwards for state and local income tax purposes of approximately $12.9 billion, of which $11.8 billion is expected to be utilized. The associated deferred tax assets, net of valuation reserves, are $267 million. These losses expire as follows:

Expiration Period	FirstEnergy	FES	Penelec
	(In millions)		
2012-2016	$885	$644	$—
2017-2021	901	33	119
2022-2026	8,402	4	94
2027-2031	2,675	408	257
	$12,863	$1,089	$470

General Taxes

Details of general taxes for the years ended 2011, 2010 and 2009, are shown below:

	FirstEnergy	FES	OE	CEI	TE	JCP&L	Met-Ed	Penelec
	(In millions)							
2011								
KWH excise	$244	$—	$90	$66	$27	$50	$—	$—
State gross receipts	264	62	17	2	1	—	64	55
Real and personal property	299	42	73	80	23	6	2	2
Social security and unemployment	109	14	9	6	3	11	5	6
Other	62	6	1	—	—	—	3	3
Total general taxes	$978	$124	$190	$154	$54	$67	$74	$66
2010								
KWH excise	$245	$5	$92	$68	$27	$51	$—	$—
State gross receipts	185	17	15	—	—	—	85	68
Real and personal property	243	53	67	70	23	5	—	(1)
Social security and unemployment	86	14	8	5	2	9	4	5
Other	17	5	1	—	—	—	(1)	1
Total general taxes	$776	$94	$183	$143	$52	$65	$88	$73
2009								
KWH excise[(1)]	$224	$1	$84	$66	$24	$49	$—	$—
State gross receipts	171	14	15	—	—	—	78	63
Real and personal property	253	53	64	74	21	5	2	2
Social security and unemployment	90	14	8	5	3	9	5	6
Other	15	5	—	—	—	—	3	3
Total general taxes	$753	$87	$171	$145	$48	$63	$88	$74

(1) KWH excise tax for OE and TE include $7 million and $3 million credit adjustments, respectively, recognized in 2009 related to prior periods.

6. LEASES

FirstEnergy leases certain generating facilities, office space and other property and equipment under cancelable and noncancelable leases.

In 1987, OE sold portions of its ownership interests in Perry Unit 1 and Beaver Valley Unit 2 and entered into operating leases on the portions sold for basic lease terms of approximately 29 years. In that same year, CEI and TE also sold portions of their ownership interests in Beaver Valley Unit 2 and Bruce Mansfield Units 1, 2 and 3 and entered into similar operating leases for lease terms of approximately 30 years. During the terms of their respective leases, OE, CEI and TE are responsible, to the extent of their leasehold interests, for costs associated with the units including construction expenditures, operation and maintenance expenses, insurance, nuclear fuel, property taxes and decommissioning. They have the right, at the expiration of the respective basic lease terms, to renew their respective leases. They also have the right to purchase the facilities at the expiration of the basic lease term or any renewal term at a price equal to the fair market value of the facilities. The basic rental payments are adjusted when applicable federal tax law changes.

In 2007, CEI and TE assigned their leasehold interests in the Bruce Mansfield Plant to FGCO, who assumed all of CEI's and TE's obligations arising under those leases. However, CEI and TE remain primarily liable on the 1987 leases and related agreements. FGCO remains primarily liable on the 2007 leases and related agreements, and FES remains primarily liable as a guarantor under the related 2007 guarantees, as to the lessors and other parties to the respective agreements. These assignments terminate automatically upon the termination of the underlying leases.

In 2007, FGCO completed a sale and leaseback transaction for its 93.825% undivided interest in Bruce Mansfield Unit 1 and entered into operating leases for basic lease terms of approximately 33 years. FES has unconditionally and irrevocably guaranteed all of FGCO’s obligations under each of the leases.

During 2008, NGC purchased 56.8 MW of lessor equity interests in the OE 1987 sale and leaseback of the Perry Plant and approximately 43.5 MW of lessor equity interests in the OE 1987 sale and leaseback of Beaver Valley Unit 2. In addition, NGC purchased 158.5 MW of lessor equity interests in the TE and CEI 1987 sale and leaseback of Beaver Valley Unit 2. The Ohio Companies continue to lease these MW under their respective sale and leaseback arrangements and the related lease debt remains outstanding.

Rentals for capital and operating leases for 2011, 2010 and 2009, are summarized as follows:

	FirstEnergy (In millions)	FES	OE	CEI	TE	JCP&L	Met-Ed	Penelec
2011								
Operating leases	$226	$197	$147	$4	$64	$8	$4	$4
Capital leases								
Interest element	6	1	—	1	—	—	—	—
Other(1)	46	34	—	—	—	—	—	—
Total rentals	$278	$232	$147	$5	$64	$8	$4	$4
2010								
Operating leases	$228	$202	$147	$4	$64	$9	$7	$4
Capital leases								
Interest element	2	1	—	1	—	—	—	—
Other(1)	35	34	—	—	—	—	1	—
Total rentals	$265	$237	$147	$5	$64	$9	$8	$4
2009								
Operating leases	$236	$202	$146	$4	$64	$9	$7	$4
Capital leases								
Interest element	1	2	1	1	—	—	—	—
Other(1)	16	18	—	—	—	—	—	—
Total rentals	$253	$222	$147	$5	$64	$9	$7	$4

(1) FirstEnergy and FES include $29 million, $30 million and $16 million, in 2011, 2010 and 2009, respectively, for wind purchased power agreements classified as capital leases.

The future minimum capital lease payments as of December 31, 2011 are as follows (TE and JCP&L have no material capital leases):

Capital leases	FirstEnergy (In millions)	FES	OE	CEI	Met-Ed	Penelec
2012	$25	$6	$2	$2	$1	$1
2013	24	6	2	2	1	1
2014	22	6	2	2	1	1
2015	20	6	2	2	1	1
2016	17	6	2	2	—	—
Years thereafter	27	5	3	2	—	—
Total minimum lease payments	135	35	13	12	4	4
Executory costs	—	—	—	—	—	—
Net minimum lease payments	135	35	13	12	4	4
Interest portion	(27)	(4)	(2)	(4)	—	—
Present value of net minimum lease payments	108	31	11	8	4	4
Less current portion	23	5	1	1	—	—
Noncurrent portion	$85	$26	$10	$7	$4	$4

Established by OE in 1996, PNBV purchased a portion of the lease obligation bonds issued on behalf of lessors in OE's Perry Unit 1 and Beaver Valley Unit 2 sale and leaseback transactions. Similarly, CEI and TE established Shippingport in 1997 to purchase the lease obligation bonds issued on behalf of lessors in their Bruce Mansfield Units 1, 2 and 3 sale and leaseback transactions. The PNBV and Shippingport arrangements effectively reduce lease costs related to those transactions (see Note 8, Variable Interest Entities).

FirstEnergy's future minimum consolidated operating lease payments as of December 31, 2011, are as follows:

Operating Leases	FirstEnergy Lease Payments (In millions)	Capital Trust[1]	Net
2012	$383	$125	$258
2013	382	130	252
2014	371	131	240
2015	373	90	283
2016	344	29	315
Years thereafter	1,803	4	1,799
Total minimum lease payments	$3,656	$509	$3,147

(1) PNBV and Shippingport purchased a portion of the lease obligation bonds associated with certain sale and leaseback transactions. These arrangements effectively reduce lease costs related to those transactions.

Operating Leases	FES (In millions)	OE[1]	CEI	TE[1]	JCP&L	Met-Ed	Penelec
2012	$237	$147	$4	$64	$7	$4	$3
2013	241	146	3	64	7	4	3
2014	236	145	3	64	6	3	2
2015	239	145	2	64	5	4	2
2016	230	117	3	64	5	3	2
Years thereafter	1,662	49	4	14	48	37	12
Total minimum lease payments	$2,845	$749	$19	$334	$78	$55	$24

(1) Includes certain minimum lease payments associated with NGC's lessor equity interests in Perry and Beaver Valley Unit 2 that are eliminated in consolidation.

FirstEnergy recorded above-market lease liabilities for Beaver Valley Unit 2 and the Bruce Mansfield Plant associated with the 1997 merger between OE and Centerior. The unamortized above-market lease liability for Beaver Valley Unit 2 of $199 million as of December 31, 2011, of which $37 million is classified as current, is being amortized by TE on a straight-line basis through the end of the lease term in 2017. The unamortized above-market lease liability for the Bruce Mansfield Plant of $217 million as of December 31, 2011, of which $46 million is classified as current, is being amortized by FGCO on a straight-line basis through the end of the lease term in 2016.

7. INTANGIBLE ASSETS

As of December 31, 2011, intangible assets classified in Other Deferred Charges on FirstEnergy's Consolidated Balance Sheet, including those recorded in connection with the Allegheny merger, include the following:

	Intangible Assets			Amortization expense						
				Actual	Estimated					
(In millions)	Gross	Accumulated Amortization	Net	2011	2012	2013	2014	2015	2016	Thereafter
NUG contracts[1][2]	$124	$4	$120	$4	$5	$5	$5	$5	$5	$95
OVEC[1]	54	1	53	1	2	2	2	2	2	43
Coal contracts[1][3]	516	74	442	56	55	53	52	45	45	108
FES customer contracts	144	21	123	12	14	16	17	17	17	42
Energy contracts[1]	136	71	65	71	50	14	1	—	—	—
	$974	$171	$803	$144	$126	$90	$77	$69	$69	$288

(1) Fair value measurements of intangible assets recorded in connection with the Allegheny merger (see Note 2, Merger)

(2) NUG contracts are subject to regulatory accounting and their amortization does not impact earnings.

(3) A gross amount of $102 million of the coal contracts was recorded with a regulatory offset and the amortization does not impact earnings. $18 million and $84 million are related to the accumulated amortization and net

amounts, respectively.

FES acquired certain customer contract rights which were capitalized as intangible assets. These rights allow FES to supply electric generation to customers, and the recorded value is being amortized ratably over the term of the related contracts.

8. 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, a portion of which was sold on October 18, 2011, and resulted in deconsolidation; the PNBV and Shippingport bond trusts that were created to refinance debt originally issued in connection with sale and leaseback transactions; 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 and JCP&L's supply of BGS, of which $287 million was outstanding as of December 31, 2011; and special purpose limited liabilities companies of MP and PE created to issue environmental control bonds that were used to construct environmental control facilities, of which $513 million was outstanding as of December 31, 2011.

FirstEnergy and its subsidiaries reflect the portion of VIEs not owned by them in the caption noncontrolling interest within the consolidated financial statements. The change in noncontrolling interest on the Consolidated Balance Sheets is primarily due to equity contributions from owners of $27 million and the deconsolidation of Signal Peak for $45 million, partially offset by net losses attributable to noncontrolling interests of $16 million and an equity distribution to owners of $5 million during the year ended December 31, 2011.

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

Mining Operations

In 2008, FEV entered into a joint venture in the Signal Peak mining and coal transportation operations near Roundup, Montana. FEV made equity investments totaling $133.5 million in exchange for a 50% economic interest in the joint venture. On October 18, 2011, a subsidiary of Gunvor Group, Ltd purchased a one-third interest in the Signal Peak joint venture in which FEV held a 50% interest. As part of the transaction, FirstEnergy received $257.5 million in proceeds and retained a 33-1/3% equity ownership in the joint venture. The sale resulted in a pre-tax gain of approximately $569 million ($370 million after-tax), which includes $378.6 million from the remeasurement of FEV's retained investment. The gain attributed to the retained investment remeasurement will be amortized as coal is extracted from the mine on a units of production method.

(In millions)	
Fair value of retained noncontrolling investment	$400.0
Less: Carrying value of retained interest	21.4
Gain on retained interest	$378.6

FirstEnergy previously consolidated this joint venture and, as a result of the sale, its retained 33-1/3% interest is accounted for using the equity method of accounting.

Trusts

FirstEnergy’s consolidated financial statements include PNBV and Shippingport - those trusts are included in the consolidated financial statements of OE and CEI, respectively. OE used debt and available funds to purchase the notes issued by PNBV for the purchase of lease obligation bonds. Ownership of PNBV includes a 3% equity interest by an unaffiliated third party and a 3% equity interest held by OES Ventures, a wholly owned subsidiary of OE. CEI and TE used debt and available funds to purchase the notes issued by Shippingport.

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 consists of its equity investment in PATH-WV, which was $29 million as of December 31, 2011.

Power Purchase Agreements

FirstEnergy evaluated its power purchase agreements and determined that certain NUG entities may be VIEs to the extent that they own a plant that sells substantially all of its output to certain of 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, it does not have a variable interest in the NUG entities or the NUG entities do not meet the criteria to be considered a VIE. JCP&L, PE and WP may hold variable interests in the remaining four entities; however, FirstEnergy applied the scope exception that exempts enterprises unable to obtain the necessary information to evaluate entities.

Because JCP&L, PE and WP have no equity or debt interests in the NUG entities, their maximum exposure to loss relates primarily to the above-market costs incurred for power. FirstEnergy expects any above-market costs incurred by its subsidiaries to be recovered from customers, 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 year ended December 31, 2011 were $176 million, $101.6 million and $48.9 million for JCP&L, PE and WP, respectively. Purchased power costs related to the two contracts that may contain a variable interest that were held by JCP&L during the years ended December 31, 2010 and 2009 were $243 million and $225 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 for which WP may hold a variable interest. As of December 31, 2011, WP's reserve for this adverse purchase power commitment was $53 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-leaseback transactions. FirstEnergy is not the primary beneficiary of these interests as it does not have control over the significant activities affecting the economics of the arrangement. FES and the Ohio Companies are exposed to losses under their applicable sale-leaseback agreements upon the occurrence of certain contingent events that each company considers unlikely to occur. The maximum exposure under these provisions represents the net amount of casualty value payments due upon the occurrence of specified casualty events that would render the applicable plant worthless. 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 December 31, 2011:

	Maximum Exposure	Discounted Lease Payments, net[1]	Net Exposure
	(In millions)		
FES	$1,362	$1,159	$203
OE	606	416	190
CEI[2]	587	71	516
TE[2]	587	309	278

(1) The net present value of FirstEnergy’s 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.

See Note 6, Leases, for a discussion of CEI's and TE's assignment of their leasehold interest in the Bruce Mansfield Plant to FGCO.

9. FAIR VALUE MEASUREMENTS

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, excluding capital lease obligations and net unamortized premiums and discounts, as of December 31, 2011 and 2010:

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	December 31, 2011		December 31, 2010	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	(In millions)			
FirstEnergy(1)	$17,165	$19,320	$13,928	$14,845
FES	3,675	3,931	4,279	4,403
OE	1,157	1,434	1,159	1,321
CEI	1,831	2,162	1,853	2,035
TE	600	741	600	653
JCP&L	1,777	2,080	1,810	1,962
Met-Ed	729	824	742	821
Penelec	1,120	1,251	1,120	1,189

(1) Includes debt assumed in the AE merger (see Note 2, Merger) with a carrying value and a fair value as of December 31, 2011, of $4,355 million and $4,561 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 securities based on the current call price, the yield to maturity or the yield to call, as deemed appropriate at the end of each respective period. The yields assumed were based on securities with similar characteristics offered by corporations with credit ratings similar to those of FirstEnergy and its subsidiaries listed above.

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. FE and its subsidiaries 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, FE and its subsidiaries 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 NDT 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 Utility Registrants hold debt and equity securities within their NDT, nuclear fuel disposal trusts and NUG trusts. These trust investments are considered available-for-sale securities at fair market value. FES and the Utility Registrants 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 December 31, 2011 and 2010:

	December 31, 2011[1]				December 31, 2010[2]			
	Cost Basis	Unrealized Gains	Unrealized Losses	Fair Value	Cost Basis	Unrealized Gains	Unrealized Losses	Fair Value
	(In millions)							
Debt securities								
FirstEnergy	$1,980	$25	$—	$2,005	$1,699	$31	$—	$1,730
FES	1,012	13	—	1,025	980	13	—	993
OE	134	—	—	134	123	1	—	124
TE	53	1	—	54	42	—	—	42
JCP&L	356	7	—	363	281	9	—	290
Met-Ed	232	2	—	234	127	4	—	131
Penelec	193	2	—	195	145	4	—	149
Equity securities								
FirstEnergy	$222	$36	$—	$258	$268	$69	$—	$337
FES	104	20	—	124	—	—	—	—
TE	22	5	—	27	—	—	—	—
JCP&L	27	3	—	30	80	17	—	97
Met-Ed	46	5	—	51	125	35	—	160
Penelec	23	3	—	26	63	16	—	79

(1) Excludes short-term cash investments: FirstEnergy — $164 million; FES — $74 million; OE — $2 million; TE — $2 million; JCP&L — $19 million; Met-Ed — $25 million and Penelec — $41 million.

(2) Excludes short-term cash investments: 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 years ended December 31, 2011, 2010 and 2009 were as follows:

December 31, 2011	Sales Proceeds	Realized Gains	Realized Losses	Interest and Dividend Income
	(In millions)			
FirstEnergy	$4,207	$229	$(90)	$82
FES	1,843	80	(46)	47
OE	154	6	—	3
TE	120	5	(5)	2
JCP&L	779	39	(11)	15
Met-Ed	860	64	(16)	8
Penelec	451	35	(12)	6

December 31, 2010	Sales Proceeds	Realized Gains	Realized Losses	Interest and Dividend Income
	(In millions)			
FirstEnergy	$3,172	$126	$(107)	$79
FES	1,927	92	(75)	47
OE	83	2	—	3
TE	126	3	(1)	2
JCP&L	411	10	(10)	14
Met-Ed	460	13	(14)	7
Penelec	165	6	(7)	6

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December 31, 2009	Sales Proceeds	Realized Gains	Realized Losses	Interest and Dividend Income
	(In millions)			
FirstEnergy	$2,229	$226	$(155)	$60
FES	1,379	199	(117)	27
OE	131	11	(4)	4
TE	169	7	(1)	2
JCP&L	397	6	(12)	14
Met-Ed	68	2	(13)	7
Penelec	84	1	(8)	6

Held-To-Maturity Securities

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

	December 31, 2011			December 31, 2010		
	Cost Basis	Unrealized Gains	Fair Value	Cost Basis	Unrealized Gains	Fair Value
	(In millions)					
Debt Securities						
FirstEnergy	$402	$50	$452	$476	$91	$567
OE	163	21	184	190	51	241
CEI	287	28	315	340	41	381

Investments in emission allowances, employee benefit trusts and cost and equity method investments totaling $693 million as of December 31, 2011, and $259 million as of December 31, 2010, 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 December 31, 2011 and 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 date of notes receivable due from affiliated companies is 2016.

	December 31, 2011		December 31, 2010	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	(In millions)			
FirstEnergy	$—	$—	$7	$8
TE(1)	81	92	104	118

(1) Represents TE's investment in the Shippingport Trust notes (see Note 6, Leases), which is eliminated during consolidation.

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.

Models are primarily industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors and current market and contractual prices for the underlying instruments, as well as other relevant economic measures.

Level 3 – Valuation inputs are unobservable and significant to the fair value measurement.

FirstEnergy develops its view of the future market price through a combination of market observation and assessment (generally for the short term) and fundamental modeling (generally for the long term). FirstEnergy utilizes market data and assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated or generally unobservable. FirstEnergy primarily applies the market approach for recurring fair value measurements using the best information available. Accordingly, FirstEnergy maximizes the use of observable inputs and minimizes the use of unobservable inputs.

The determination of the fair value measures takes into consideration various factors. These factors include, but are not limited to, nonperformance risk, including counterparty credit risk and the impact of credit enhancements (such as cash deposits, LOCs and priority interests). The impact of these forms of risk were not significant in the fair value measurements.

The following tables set forth financial assets and liabilities that are accounted for at fair value by level within the fair value hierarchy. There were no significant transfers between levels during 2011 and 2010.

FIRSTENERGY

	December 31, 2011				December 31, 2010			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets	(In millions)							
Corporate debt securities	$—	$1,544	$—	$1,544	$—	$597	$—	$597
Derivative assets — commodity contracts	—	264	—	264	—	250	—	250
Derivative assets — FTRs	—	—	1	1	—	—	—	—
Derivative assets — NUG contracts[1]	—	—	56	56	—	—	122	122
Equity securities[2]	259	—	—	259	338	—	—	338
Foreign government debt securities	—	3	—	3	—	149	—	149
U.S. government debt securities	—	148	—	148	—	595	—	595
U.S. state debt securities	—	314	—	314	—	379	—	379
Other[3]	—	225	—	225	—	219	—	219
Total assets	$259	$2,498	$57	$2,814	$338	$2,189	$122	$2,649
Liabilities								
Derivative liabilities — commodity contracts	$—	$(247)	$—	$(247)	$—	$(348)	$—	$(348)
Derivative liabilities — FTRs	—	—	(23)	(23)	—	—	—	—
Derivative liabilities — NUG contracts[1]	—	—	(349)	(349)	—	—	(466)	(466)
Total liabilities	$—	$(247)	$(372)	$(619)	$—	$(348)	$(466)	$(814)
Net assets (liabilities)[4]	$259	$2,251	$(315)	$2,195	$338	$1,841	$(344)	$1,835

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

(2) NDT funds hold equity portfolios whose performance is benchmarked against the Alerian MLP Index.

(3) Primarily consists of short-term cash investments.

(4) Excludes $(52) million and $(7) million as of December 31, 2011 and 2010, respectively, of receivables, payables, taxes and accrued income associated with financial instruments reflected within the fair value table.

Rollforward of Level 3 Measurements

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

	Derivative Assets[1]	Derivative Liabilities[1]	Net[1]
	(In millions)		
December 31, 2009 Balance	$200	$(643)	$(443)
Realized gain (loss)	—	—	—
Unrealized gain (loss)	(71)	(110)	(181)
Purchases	—	—	—
Issuances	—	—	—
Sales	—	—	—
Settlements	(7)	287	280
Transfers in (out) of Level 3	—	—	—
December 31, 2010 Balance	$122	$(466)	$(344)
Realized gain (loss)	—	—	—
Unrealized gain (loss)	(55)	(173)	(228)
Purchases	13	(4)	9
Issuances	—	—	—
Sales	—	—	—
Settlements	(23)	283	260
Transfers in (out) of Level 3	—	(12)	(12)
December 31, 2011 Balance	$57	$(372)	$(315)

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

FES

	December 31, 2011				December 31, 2010			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets	(In millions)							
Corporate debt securities	$—	$1,010	$—	$1,010	$—	$528	$—	$528
Derivative assets — commodity contracts	—	248	—	248	—	241	—	241
Derivative assets — FTRs	—	—	1	1	—	—	—	—
Equity securities[1]	124	—	—	124	—	—	—	—
Foreign government debt securities	—	3	—	3	—	147	—	147
U.S. government debt securities	—	7	—	7	—	308	—	308
U.S. state debt securities	—	5	—	5	—	6	—	6
Other[2]	—	132	—	132	—	148	—	148
Total assets	$124	$1,405	$1	$1,530	$—	$1,378	$—	$1,378
Liabilities								
Derivative liabilities — commodity contracts	$—	$(234)	$—	$(234)	$—	$(348)	$—	$(348)
Derivative liabilities — FTRs	—	—	(7)	(7)	—	—	—	—
Total liabilities	$—	$(234)	$(7)	$(241)	$—	$(348)	$—	$(348)
Net assets (liabilities)[3]	$124	$1,171	$(6)	$1,289	$—	$1,030	$—	$1,030

(1) NDT funds hold equity portfolios whose performance of which is benchmarked against the Alerian MLP Index.

(2) Primarily consists of short-term cash investments.

(3) Excludes $(58) million and $7 million as of December 31, 2011 and 2010, respectively, of receivables, payables, taxes and accrued income associated with the financial instruments reflected within the fair value table.

Rollforward of Level 3 Measurements

The following table provides a reconciliation of changes in the fair value of FTRs held by FES and classified as Level 3 in the fair value hierarchy for the years ending December 31, 2011 and 2010:

	Derivative Asset FTRs	Derivative Liability FTRs	Net FTRs
	(In millions)		
December 31, 2010 Balance	$—	$—	$—
Realized gain (loss)	—	—	—
Unrealized gain (loss)	4	(8)	(4)
Purchases	2	(1)	1
Issuances	—	—	—
Sales	—	—	—
Settlements	(5)	2	(3)
Transfers in (out) of Level 3	—	—	—
December 31, 2011 Balance	$1	$(7)	$(6)

OE

	December 31, 2011				December 31, 2010			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets	(In millions)							
Corporate debt securities	$—	$3	$—	$3	$—	$—	$—	$—
U.S. government debt securities	—	132	—	132	—	124	—	124
Other[(1)]	—	2	—	2	—	2	—	2
Total assets[(2)]	$—	$137	$—	$137	$—	$126	$—	$126

(1) Primarily consists of short-term cash investments.

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

TE

	December 31, 2011				December 31, 2010			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets	(In millions)							
Corporate debt securities	$—	$53	$—	$53	$—	$7	$—	$7
Equity securities[(1)]	27	—	—	27	—	—	—	—
U.S. government debt securities	—	—	—	—	—	33	—	33
U.S. state debt securities	—	—	—	—	—	1	—	1
Other[(2)]	—	3	—	3	—	35	—	35
Total assets	$27	$56	$—	$83	$—	$76	$—	$76

(1) NDT funds hold equity portfolios whose performance is benchmarked against the Alerian MLP Index.

(2) Primarily consists of short-term cash investments.

JCP&L

	December 31, 2011				December 31, 2010			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets	(In millions)							
Corporate debt securities	$—	$144	$—	$144	$—	$23	$—	$23
Derivative assets — commodity contracts	—	—	—	—	—	2	—	2
Derivative assets — NUG contracts[1]	—	—	4	4	—	—	6	6
Equity securities[2]	30	—	—	30	96	—	—	96
U.S. government debt securities	—	2	—	2	—	33	—	33
U.S. state debt securities	—	219	—	219	—	236	—	236
Other[3]	—	15	—	15	—	4	—	4
Total assets	$30	$380	$4	$414	$96	$298	$6	$400
Liabilities								
Derivative liabilities — NUG contracts[1]	$—	$—	$(147)	$(147)	$—	$—	$(233)	$(233)
Total liabilities	$—	$—	$(147)	$(147)	$—	$—	$(233)	$(233)
Net assets (liabilities)[4]	$30	$380	$(143)	$267	$96	$298	$(227)	$167

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

(2) NDT funds hold equity portfolios whose performance is benchmarked against the Alerian MLP Index.

(3) Primarily consists of short-term cash investments.

(4) Excludes $2 million and $(3) million as of December 31, 2011 and December 31, 2010 of receivables, payables, taxes and accrued income associated with the financial instruments reflected within the fair value table.

Rollforward of Level 3 Measurements

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

	Derivative Asset NUG Contracts[1]	Derivative Liability NUG Contracts[1]	Net NUG Contracts[1]
	(In millions)		
December 31, 2009 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)
Realized gain (loss)	—	—	—
Unrealized gain (loss)	(2)	(11)	(13)
Purchases	—	—	—
Issuances	—	—	—
Sales	—	—	—
Settlements	—	97	97
Transfers in (out) of Level 3	—	—	—
December 31, 2011 Balance	$4	$(147)	$(143)

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

MET-ED

	December 31, 2011				December 31, 2010			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets	(In millions)							
Corporate debt securities	$—	$229	$—	$229	$—	$32	$—	$32
Derivative assets — commodity contracts	—	—	—	—	—	5	—	5
Derivative assets — NUG contracts[1]	—	—	49	49	—	—	112	112
Equity securities[2]	51	—	—	51	160	—	—	160
Foreign government debt securities	—	—	—	—	—	1	—	1
U.S. government debt securities	—	5	—	5	—	88	—	88
U.S. state debt securities	—	—	—	—	—	2	—	2
Other[3]	—	23	—	23	—	14	—	14
Total assets	$51	$257	$49	$357	$160	$142	$112	$414
Liabilities								
Derivative liabilities — NUG contracts[1]	$—	$—	$(79)	$(79)	$—	$—	$(116)	$(116)
Total liabilities	$—	$—	$(79)	$(79)	$—	$—	$(116)	$(116)
Net assets (liabilities)[4]	$51	$257	$(30)	$278	$160	$142	$(4)	$298

(1) NUG contracts are subject to regulatory accounting and do not impact earnings.
(2) NDT funds hold equity portfolios whose performance is benchmarked against the Alerian MLP Index.
(3) Primarily consists of short-term cash investments.
(4) Excludes $2 million and $(9) million as of December 31, 2011 and 2010, respectively, of receivables, payables, taxes and accrued income associated with the financial instruments reflected within the fair value table.

Rollforward of Level 3 Measurements

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

	Derivative Asset NUG Contracts[1]	Derivative Liability NUG Contracts[1]	Net NUG Contracts[1]
	(In millions)		
December 31, 2009 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)
Realized gain (loss)	—	—	—
Unrealized gain (loss)	(57)	(31)	(88)
Purchases	—	—	—
Issuances	—	—	—
Sales	—	—	—
Settlements	(6)	68	62
Transfers in (out) of Level 3	—	—	—
December 31, 2011 Balance	$49	$(79)	$(30)

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

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PENELEC

	December 31, 2011				December 31, 2010			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets	(In millions)							
Corporate debt securities	$—	$104	$—	$104	$—	$8	$—	$8
Derivative assets — commodity contracts	—	—	—	—	—	2	—	2
Derivative assets — NUG contracts[1]	—	—	3	3	—	—	4	4
Equity securities[2]	26	—	—	26	81	—	—	81
U.S. government debt securities	—	2	—	2	—	9	—	9
U.S. state debt securities	—	90	—	90	—	133	—	133
Other[3]	—	39	—	39	—	5	—	5
Total assets	$26	$235	$3	$264	$81	$157	$4	$242
Liabilities								
Derivative liabilities — NUG contracts[1]	$—	$—	$(123)	$(123)	$—	$—	$(117)	$(117)
Total liabilities	$—	$—	$(123)	$(123)	$—	$—	$(117)	$(117)
Net assets (liabilities)[4]	$26	$235	$(120)	$141	$81	$157	$(113)	$125

(1) NUG contracts are subject to regulatory accounting and do not impact earnings.
(2) NDT funds hold equity portfolios whose performance is benchmarked against the Alerian MLP Index.
(3) Primarily consists of short-term cash investments.
(4) Excludes $1 million and $(3) million as of December 31, 2011 and 2010, respectively, of receivables, payables, taxes and accrued income associated with the financial instruments reflected within the fair value table.

Rollforward of Level 3 Measurements

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

	Derivative Asset NUG Contracts[1]	Derivative Liability NUG Contracts[1]	Net NUG Contracts[1]
	(In millions)		
December 31, 2009 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)
Realized gain (loss)	—	—	—
Unrealized gain (loss)	—	(103)	(103)
Purchases	—	—	—
Issuances	—	—	—
Sales	—	—	—
Settlements	(1)	97	96
Transfers in (out) of Level 3	—	—	—
December 31, 2011 Balance	$3	$(123)	$(120)

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

During 2011, FirstEnergy received approximately $130 million from assigning a substantially below-market, long-term fossil fuel contract to a third party. As a result, FirstEnergy entered into a new long-term contract with another supplier for replacement fuel based on current market prices. The new contract runs for nine years, which is the remaining term of the assigned contract. The transaction reduced fuel costs during the year by approximately $123 million.

10. 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 Risk Policy 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. 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 qualified and were designated as cash flow hedge instruments are recorded in AOCI. 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 a derivative contract are reported as a component of AOCI 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 AOCI associated with dedesignated cash flow hedges totaled $19 million as of December 31, 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 AOCI into other operating expenses were $26 million for the year ended December 31, 2011. Approximately $9 million is expected to be amortized to income 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 December 31, 2011, no forward starting swap agreements were outstanding. Total unamortized losses included in AOCI associated with prior interest rate cash flow hedges totaled $79 million as of December 31, 2011. Based on current estimates, approximately $9 million will be amortized to interest expense during the next twelve months. Reclassifications from AOCI into interest expense totaled $12 million and $11 million during 2011 and 2010, respectively.

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 portfolios 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 December 31, 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 $102 million as of December 31, 2011. Based on current estimates, approximately $22 million will be amortized to interest expense during the next twelve months. Reclassifications from long-term debt into interest expense totaled approximately $22 million and $12 million during 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 at 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. Derivative instruments are not used in quantities greater than forecasted needs.

As of December 31, 2011, FirstEnergy's net asset position under commodity derivative contracts was $17 million. Under these commodity derivative contracts, FES posted $52 million and AE Supply posted $1 million in collateral. Certain commodity derivative contracts include credit risk-related contingent features that would require FES to post $28 million and AE Supply to post $2 million of additional collateral if the credit rating for its debt were to fall below investment grade.

Based on commodity derivative contracts held as of December 31, 2011, an adverse 10% change in commodity prices would decrease net income by approximately $13 million 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 (June 1, 2011, through May 31, 2013, for the Ohio Companies), 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 FirstEnergy's 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 fiscal quarter 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.

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

Derivatives not designated as hedging instruments:

Derivative Assets			Derivative Liabilities		
	Fair Value			Fair Value	
	December 31, 2011	December 31, 2010		December 31, 2011	December 31, 2010
	(In millions)			(In millions)	
Power Contracts			Power Contracts		
Current Assets	$185	$96	Current Liabilities	$(196)	$(209)
Noncurrent Assets	79	40	Noncurrent Liabilities	(51)	(38)
FTRs			FTRs		
Current Assets	1	—	Current Liabilities	(22)	—
Noncurrent Assets	—	—	Noncurrent Liabilities	(1)	—
NUGs	56	122	NUGs	(349)	(467)
Interest Rate Swaps			Interest Rate Swaps		
Current Assets	—	—	Current Liabilities	—	—
Noncurrent Assets	—	—	Noncurrent Liabilities	—	—
Other			Other		
Current Assets	—	10	Current Liabilities	—	—
Noncurrent Assets	—	—	Noncurrent Liabilities	—	—
Total Derivatives Assets	$321	$268	Total Derivatives Liabilities	$(619)	$(714)

The following table summarizes the volumes associated with FirstEnergy’s outstanding derivative transactions as of December 31, 2011:

	Purchases	Sales	Net
	(In thousands of MWH)		
Power Contracts	32,188	49,737	(17,549)
FTRs	32,534	—	32,534
NUGs	23,981	—	23,981

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The following tables summarize the effect of derivative instruments on the Consolidated Statements of Income during 2011 and 2010:

	Power Contracts (In millions)	FTRs	Other	Total
Derivatives in a Hedging Relationship				
December 31, 2011				
Gain Recognized in AOCI (Effective Portion)	$11	$—	$1	$12
Effective Gain (Loss) Reclassified to:[1]				
Purchased Power Expense	16	—	—	16
Revenues	(12)	—	—	(12)
December 31, 2010				
Gain Recognized in AOCI (Effective Portion)	$12	$—	$11	$23
Effective Loss Reclassified to:[1]				
Purchased Power Expense	(7)	—	—	(7)
Revenues	(4)	—	—	(4)
Fuel Expense	—	—	(14)	(14)
Derivatives Not in a Hedging Relationship				
December 31, 2011				
Unrealized Gain (Loss) Recognized in:				
Purchased Power Expense	$120	$—	$—	$120
Revenues	(3)	—	—	(3)
Other Operating Expense	(52)	(14)	2	(64)
Realized Gain (Loss) Reclassified to:				
Purchased Power Expense	(159)	—	—	(159)
Revenues	17	67	—	84
Other Operating Expense	—	(157)	—	(157)
December 31, 2010				
Unrealized Gain Recognized in:				
Purchased Power Expense	$86	$—	$—	$86
Realized Loss Reclassified to:				
Purchased Power Expense	(104)	—	—	(104)

Derivatives Not in a Hedging Relationship Generally Subject to Regulatory Offset[2]	NUGs	Other	Total
	(In millions)		
December 31, 2011			
Unrealized Loss to Derivative Instrument	$(202)	$(5)	$(207)
Unrealized Gain to Regulatory Assets	202	5	207
Realized Gain (Loss) to Derivative Instrument	254	(13)	241
Realized Gain (Loss) to Regulatory Assets	(254)	13	(241)
December 31, 2010			
Unrealized Loss to Derivative Instrument	$(181)	—	$(181)
Unrealized Gain to Regulatory Assets	181	—	181
Realized Gain (Loss) to Derivative Instrument	280	(9)	271
Realized Gain (Loss) to Regulatory Assets	(280)	9	(271)

[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.

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The following table provides a reconciliation of changes in the fair value of certain contracts that are deferred for future recovery from (or credit to) customers during 2011 and 2010:

Derivatives Not in a Hedging Relationship Generally Subject to Regulatory Offset	NUGs	Other	Total
	(In millions)		
Outstanding net asset (liability) as of January 1, 2010	$(444)	$19	$(425)
Additions/Change in value of existing contracts	(181)	—	(181)
Settled contracts	280	(9)	271
Outstanding net asset (liability) as of December 31, 2010	(345)	10	(335)
Additions/Change in value of existing contracts	(202)	(5)	(207)
Settled contracts	254	(13)	241
Outstanding net asset (liability) as of December 31, 2011	$(293)	$(8)	$(301)

11. IMPAIRMENT OF LONG-LIVED ASSETS

FirstEnergy reviews long-lived assets, including regulatory 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.

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 included 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 in the first quarter of 2011. On July 28, 2011, FirstEnergy completed the sale of Fremont Energy Center to American Municipal Power, Inc.

Peaking Facilities

During 2011, FirstEnergy assessed the carrying values of certain peaking facilities that were more likely than not to 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 the evaluation indicated that the carrying costs of the peaking facilities were not fully recoverable. FirstEnergy recorded impairment charges of $23 million during 2011 as a result of the recoverability evaluation and on October 18, 2011, FirstEnergy closed on the sale of the Richland and Stryker peaking facilities.

Generating Plant Retirements

On January 26, 2012, FirstEnergy announced that it will retire certain coal-fired generating plants owned by FGCO or AE Supply: Bay Shore Units 2-4, Eastlake Units 1-5, Ashtabula, Lake Shore, Armstrong Units 1-2 and R. Paul Smith Units 3-4. On February 8, 2012, FirstEnergy announced that it will retire three additional coal-fired generation plants owned by MP: Albright, Willow Island and Rivesville. All of these generating plants are expected to be closed by September 1, 2012 and are subject to review by PJM for reliability impacts (see Note 16, Commitment, Guarantees and Contingencies, regarding PJM's review of the Company's plans). The decision to close the plants is the result of a comprehensive review of FirstEnergy's coal-fired generating facilities in light of the MATS rules that were recently finalized and other environmental requirements.

As a result of this decision, FirstEnergy recorded a pre-tax impairment of $334 million to continuing operations during the year ended 2011. This impairment consists of a $311 million write down of the carrying value of the plant assets, approximately $5 million in excessive SO_2 emission allowances and an $18 million charge for excessive or obsolete inventory at these facilities.

In addition to the emission allowance impairments in connection with the plant closures, FirstEnergy recorded during 2011, pre-tax impairment charges of approximately $6 million ($1 million for FES and $5 million for AE Supply) for NOx emission allowances that were expected to be obsolete after 2011 and approximately $16 million ($13 million for FES and $3 million for AE Supply) for excess SO_2 emission allowances in inventory that it expects will not be consumed in the future.

In total, 634 employees will be directly affected by this decision. Existing severance benefits will apply to those that are eligible, however, the number of affected employees could be less as some are considered for open positions at other FirstEnergy facilities and other locations. In addition, a VSP will be offered to retirement-eligible affected employees who work at the plants being closed. Under the VSP, employees will receive an enhanced one-time lump sum severance payment in exchange for agreeing to remain an active employee until a date determined by FirstEnergy. Normal retirement benefits are unchanged by the VSP.

FirstEnergy estimates that the total severance benefits may be up to $25 million ($15 million - FGCO; $5 million - AE Supply; $5 million - MP). It is also estimated that additional costs to prepare the plants for closing during 2012 will be approximately $9 million ($4 million - FGCO; $3 million - AE Supply; $2 million - MP). FGCO, AE Supply and MP have other obligations that could be affected by the plant closings and are currently unable to reasonably estimate potential costs, or a range thereof, that could be incurred.

12. CAPITALIZATION

COMMON STOCK

Retained Earnings and Dividends

As of December 31, 2011, FirstEnergy's unrestricted retained earnings were $3.0 billion. Dividends declared in 2011 were $2.20 per share, which includes dividends of $0.55 per share paid in the second, third and fourth quarters of 2011 and dividends of $0.55 per share payable in the first quarter of 2012. Dividends declared in 2010 were $2.20 per share, which includes dividends of $0.55 per share paid in the second, third and fourth quarter of 2010 and dividends of $0.55 per share paid in the first quarter of 2011. The amount and timing of all dividend declarations are subject to the discretion of the Board of Directors and its consideration of business conditions, results of operations, financial condition and other factors.

In addition to paying dividends from retained earnings, OE, CEI, TE, Penn, JCP&L, Met-Ed and Penelec have authorization from the FERC to pay cash dividends to FirstEnergy from paid-in capital accounts, as long as their equity to total capitalization ratio (without consideration of retained earnings) remains above 35%. In addition, TrAIL and AGC have authorization from the FERC to pay cash dividends to FE from paid-in capital accounts, as long as their equity to total capitalization ratio (without consideration of retained earnings) remains above 50% and 45%, respectively. The articles of incorporation, indentures, regulatory limitations and various other agreements relating to the long-term debt of certain FirstEnergy subsidiaries contain provisions that could further restrict the payment of dividends on their common stock. None of these provisions materially restricted FirstEnergy's subsidiaries' abilities to pay cash dividends to FirstEnergy as of December 31, 2011.

As described in Note 1, Organization Basis of Presentation and Significant Accounting Policies, FirstEnergy elected to change its method of recognizing actuarial gains and losses for its defined benefit pension plans and other postemployment benefit plans and applied this change retrospectively to all periods presented. The retrospective application of this change caused accumulated deficits for certain of the Utility Registrants during those prior periods, including periods when dividends were paid from retained earnings. Previous to this accounting change, retained earnings were sufficient for those dividends that were declared and paid.

PREFERRED AND PREFERENCE STOCK

FirstEnergy and the Utilities were authorized to issue preferred stock and preference stock as of December 31, 2011, as follows:

	Preferred Stock		Preference Stock	
	Shares Authorized	Par Value	Shares Authorized	Par Value
FirstEnergy	5,000,000	$100		
OE	6,000,000	$100	8,000,000	no par
OE	8,000,000	$25		
Penn	1,200,000	$100		
CEI	4,000,000	no par	3,000,000	no par
TE	3,000,000	$100	5,000,000	$25
TE	12,000,000	$25		
JCP&L	15,600,000	no par		
Met-Ed	10,000,000	no par		
Penelec	11,435,000	no par		
MP	940,000	$100		
PE	10,000,000	$0.01		
WP	32,000,000	no par		

As of December 31, 2011, and 2010, there were no preferred shares or preference shares outstanding.

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LONG-TERM DEBT AND OTHER LONG-TERM OBLIGATIONS

The following tables present outstanding long-term debt and capital lease obligations for FirstEnergy, FES and the Utility Registrants as of December 31, 2011 and 2010:

	As of December 31, 2011		As of December 31,	
(Dollar amounts in millions)	Maturity Date	Interest Rate	2011	2010
FirstEnergy:				
FMBs	2012 - 2038	5.125% - 9.740%	$2,487	$1,023
Secured notes - fixed rate	2012 - 2037	3.000% - 7.880%	2,725	2,727
Secured notes - variable rate	2012	0.090%	50	57
Total secured notes			2,775	2,784
Unsecured notes - fixed rate	2012 - 2039	2.225% - 8.250%	10,961	9,351
Unsecured notes - variable rate	2012 - 2013	0.030% - 2.918%	782	770
Total unsecured notes			11,743	10,121
Capital lease obligations			108	54
Unamortized debt premiums			64	83
Unamortized merger fair value adjustments			160	—
Currently payable long-term debt			(1,621)	(1,486)
Total long-term debt and other long-term obligations			$15,716	$12,579
FES:				
Secured notes - fixed rate	2012 - 2018	3.000% - 7.250%	$899	$838
Secured notes - variable rate	2012	0.090%	50	434
Total secured notes			949	1,272
Unsecured notes - fixed rate	2012 - 2039	2.250% - 6.800%	2,218	2,562
Unsecured notes - variable rate	2012	0.040% - 0.090%	508	445
Total unsecured notes			2,726	3,007
Capital lease obligations			31	36
Unamortized debt discounts			(2)	(2)
Currently payable long-term debt			(905)	(1,132)
Total long-term debt and other long-term obligations			$2,799	$3,181
OE:				
FMBs	2012 - 2038	8.250%	$407	$408
Unsecured notes - fixed rate	2015 - 2038	5.450% - 6.875%	750	750
Capital lease obligations			11	7
Unamortized debt discounts			(11)	(12)
Currently payable long-term debt			(2)	(1)
Total long-term debt and other long-term obligations			$1,155	$1,152
CEI:				
FMBs	2018 - 2024	5.500% - 8.875%	$600	$600
Secured notes - fixed rate	2017	7.880%	300	300
Unsecured notes - fixed rate	2013 - 2036	5.650% - 5.950%	850	850
Unsecured notes due to affiliates	2012 - 2016	7.663%	81	103
Capital lease obligations			8	3

Unamortized debt discounts	(3)	(3)
Currently payable long-term debt	(1)	—
Total long-term debt and other long-term obligations	$1,835	$1,853

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(Dollar amounts in millions)	As of December 31, 2011 Maturity Date	Interest Rate	As of December 31, 2011	2010
TE:				
Secured notes - fixed rate	2020 - 2037	6.150% - 7.250%	$600	$600
Capital lease obligations			1	3
Unamortized debt discounts			(2)	(3)
Total long-term debt and other long-term obligations			$599	$600
JCP&L:				
Secured notes - fixed rate	2012 - 2021	5.250% - 6.160%	$277	$310
Unsecured notes - fixed rate	2016 - 2037	4.800% - 7.350%	1,500	1,500
Unamortized debt discounts			(7)	(8)
Currently payable long-term debt			(34)	(32)
Total long-term debt			$1,736	$1,770
Met-Ed:				
FMBs			$—	$14
Unsecured notes - fixed rate	2013 - 2019	4.875% - 7.700%	700	700
Unsecured notes - variable rate	2012	0.090%	29	29
Total unsecured notes			729	729
Capital lease obligations			4	5
Currently payable long-term debt			(29)	(29)
Total long-term debt and other long-term obligations			$704	$719
Penelec:				
Unsecured notes - fixed rate	2014 - 2038	5.125% - 6.625%	$1,075	$1,100
Unsecured notes - variable rate	2012	0.030% - 0.090%	45	20
Total unsecured notes			1,120	1,120
Capital lease obligations			4	—
Unamortized debt discounts			(2)	(3)
Currently payable long-term debt			(46)	(45)
Total long-term debt and other long-term obligations			$1,076	$1,072

See Note 6, Leases for additional information related to capital leases.

Securitized Bonds

Environmental Control Bonds

The consolidated financial statements of FirstEnergy include environmental control bonds issued by two bankruptcy remote, special purpose limited liability companies that are indirect subsidiaries of MP and PE. Proceeds from the bonds were used to construct environmental control facilities. The special purpose limited liability companies own the irrevocable right to collect non-bypassable environmental control charges from all customers who receive electric delivery service in MP's and PE's West Virginia service territories. Principal and interest owed on the environmental control bonds is secured by, and payable solely from, the proceeds of the environmental control charges. The right to collect environmental control charges is not included on FirstEnergy's consolidated balance sheets. Creditors of FirstEnergy, other than the special purpose limited liability companies, have no recourse to any assets or revenues of the special purpose limited liability companies. As of December 31, 2011, $513 million of environmental control bonds were outstanding.

Transition Bonds

The consolidated financial statements of FirstEnergy and JCP&L include the accounts of JCP&L Transition Funding and JCP&L Transition Funding II, wholly owned limited liability companies of JCP&L. In June 2002, JCP&L Transition Funding sold transition bonds to securitize the recovery of JCP&L's bondable stranded costs associated with the previously divested Oyster Creek Nuclear Generating Station. In August 2006, JCP&L Transition Funding II sold transition bonds to securitize the recovery of deferred costs associated with JCP&L's supply of BGS. JCP&L did not purchase and does not own any of the transition bonds, which are included as long-term debt on FirstEnergy's and JCP&L's Consolidated Balance Sheets, and the transition bonds are the sole obligations of JCP&L Transition Funding and JCP&L Transition Funding II and are collateralized by each company's equity and assets, which consist primarily of bondable transition property. As of December 31, 2011, $287 million of the transition bonds were outstanding.

Bondable transition property represents the irrevocable right under New Jersey law of a utility company to charge, collect and receive from its customers, through a non-bypassable TBC, the principal amount and interest on transition bonds and other fees and expenses associated with their issuance. JCP&L sold its bondable transition property to JCP&L Transition Funding and JCP&L Transition Funding II and, as servicer, manages and administers the bondable transition property, including the billing, collection and remittance of the TBC, pursuant to separate servicing agreements with JCP&L Transition Funding and JCP&L Transition Funding II. For the two series of transition bonds, JCP&L is entitled to aggregate annual servicing fees of up to $628 thousand that are payable from TBC collections.

Other Long-term Debt

The Ohio Companies, Penn, FGCO and NGC each have a first mortgage indenture under which they can issue FMBs secured by a direct first mortgage lien on substantially all of their property and franchises, other than specifically excepted property.

Based on the amount of FMBs authenticated by the respective mortgage bond trustees as of December 31, 2011, the sinking fund requirement for all FMBs issued under the various mortgage indentures amounted to payments, all of which relate to Penn, was $6 million in 2011. Penn expects to meet its 2011 annual sinking fund requirement with a replacement credit under its mortgage indenture.

As of December 31, 2011, FirstEnergy's currently payable long-term debt includes approximately $632 million (FES — $558 million, Penelec — $45 million and Met-Ed — $29 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 following table presents scheduled debt repayments for outstanding long-term debt, excluding capital leases, fair value purchase accounting adjustments and unamortized debt discounts and premiums, for the next five years as of December 31, 2011. TE does not have any long-term debt payments due during the next five years. PCRBs that can be tendered for mandatory purchase prior to maturity are reflected in 2012.

Year	FirstEnergy	FES	OE	CEI	JCP&L	Met-Ed	Penelec
	(In millions)						
2012	$1,605	$896	$—	$—	$34	$29	$45
2013	1,314	310	—	300	36	150	—
2014	878	125	—	—	38	250	150
2015	1,638	762	150	—	41	—	—
2016	1,050	191	250	—	343	—	—

The following table classifies the outstanding variable rate put bond PCRBs and variable rate PCRBs by year, excluding unamortized debt discounts and premiums, for the next five years based on the next date on which the debt holders may exercise their right to tender their PCRBs. The Ohio Companies and JCP&L did not have any outstanding PCRBs as of December 31, 2011.

Year	FirstEnergy	FES	Met-Ed	Penelec
	(In millions)			
2012	$901	$828	$28	$45
2013	235	235	—	—
2014	26	26	—	—
2015	313	313	—	—
2016	170	170	—	—

Obligations to repay certain PCRBs are secured by several series of FMBs. Certain PCRBs are entitled to the benefit of irrevocable bank LOCs , to pay principal of, or interest on, the applicable PCRBs. To the extent that drawings are made under the LOCs, FGCO, NGC and the applicable Utilities are entitled to a credit against their obligation to repay those bonds. FGCO, NGC and the applicable Utilities pay annual fees based on the amounts of the LOCs to the issuing banks and are obligated to reimburse the banks or insurers, as the case may be, for any drawings thereunder. The insurers hold FMBs as security for such reimbursement obligations. In addition, OE has LOCs of $116 million and $37 million in connection with the sale and leaseback of Beaver Valley Unit 2 and Perry Unit 1, respectively.

The amounts and annual fees for PCRB-related LOCs for FirstEnergy, FGCO, NGC, Met-Ed and Penelec as of December 31, 2011, are as follows:

	Aggregate LOC Amount	Annual Fees
	(In millions)	
FGCO	$365	1.71% to 3.30%
NGC	200	1.71%
Met-Ed	29	1.75%
Penelec	45	1.71% to 1.75%
	$639	

Debt Covenant Default Provisions

FirstEnergy has various debt covenants under certain financing arrangements, including its revolving credit facilities. The most restrictive of the debt covenants relate to the nonpayment of interest and/or principal on such debt and the maintenance of certain financial ratios. The failure by FirstEnergy to comply with the covenants contained in its financing arrangements could result in an event of default, which may have an adverse effect on its financial condition.

Additionally, there are cross-default provisions in a number of the financing arrangements. These provisions generally trigger a default in the applicable financing arrangement of an entity if it or any of its significant subsidiaries default under another financing arrangement in excess of a certain principal amount, typically $100 million. Although such defaults by any of the Utilities, ATSI or TrAIL would generally cross-default FirstEnergy financing arrangements containing these provisions, defaults by any of AE Supply, FES, FGCO or NGC would generally not cross-default to applicable financing arrangements of FirstEnergy. Also, defaults by FirstEnergy would generally not cross-default applicable financing arrangements of any of FirstEnergy's subsidiaries. Cross-default provisions are not typically found in any of the senior notes or FMBs of FirstEnergy, FGCO, NGC or the Utilities.

13. SHORT-TERM BORROWINGS AND BANK LINES OF CREDIT

FirstEnergy had no significant short-term borrowings as of December 31, 2011, and short-term borrowings of approximately $700 million as of December 31, 2010. FirstEnergy's available liquidity as of January 31, 2012, was as follows:

Company	Type	Maturity	Commitment	Available Liquidity
			(In millions)	
FirstEnergy[1]	Revolving	June 2016	$2,000	$1,395
FES / AE Supply	Revolving	June 2016	2,500	2,498
TrAIL	Revolving	Jan. 2013	450	450
AGC	Revolving	Dec. 2013	50	—
		Subtotal	$5,000	$4,343
		Cash	—	49
		Total	$5,000	$4,392

[1] FE and the Utilities

Revolving Credit Facilities

FirstEnergy and FES / AE Supply Facilities

FirstEnergy and certain of its subsidiaries participate in two five-year syndicated revolving credit facilities with aggregate commitments of $4.5 billion (Facilities).

An aggregate amount of $2 billion is available to be borrowed under a syndicated revolving credit facility (FirstEnergy Facility), subject to separate borrowing sublimits for each borrower. The borrowers under the FirstEnergy Facility are FE, OE, Penn, CEI, TE, Met-Ed, 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 (FES/AE Supply Facility), subject to separate borrowing sublimits for each borrower.

Commitments under each of the 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 Facilities are available to each borrower separately and 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 Facilities are subject to the usual and customary provisions for acceleration upon the occurrence of events of default, including a cross-default for other indebtedness in excess of $100 million, as described further in Note 12, Capitalization.
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 December 31, 2011:

Borrower	Revolving Credit Facility Sub-Limit	Regulatory and Other Short-Term Debt Limitations	
	(In millions)		
FE	$2,000	—	(1)
FES	$1,500	—	(2)
AE Supply	$1,000	—	(2)
OE	$500	$500	
CEI	$500	$500	
TE	$500	$500	
JCP&L	$425	$411	(3)
Met-Ed	$300	$300	(3)
Penelec	$300	$300	(3)
West Penn	$200	$200	(3)
MP	$150	$150	(3)
PE	$150	$150	(3)
ATSI	$100	$100	
Penn	$50	$33	(3)

(1) No limitations.
(2) No limitation based upon blanket financing authorization from the FERC under existing open market tariffs.
(3) Excluding amounts which may be borrowed under the regulated companies' money pool.

The entire amount of the FES/AE Supply Facility and $700 million of the 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 Facilities and against the applicable borrower's borrowing sub-limit.

AGC and TrAIL Revolving Credit Facilities

FirstEnergy also has established $500 million of revolving credit facilities that are available to TrAIL ($450 million) and AGC ($50 million) until January 2013 and December 2013, respectively.

FirstEnergy Money Pools

FirstEnergy's regulated companies also have the ability to borrow from each other and the holding company to meet their short-term working capital requirements. A similar but separate arrangement exists among 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 during 2011 was 0.44% per annum for the regulated companies' money pool and 0.42% per annum for the unregulated companies' money pool.

Weighted Average Interest Rates

The weighted average interest rates on short-term borrowings outstanding, including borrowings under the FirstEnergy Money Pools, as of December 31, 2011 and 2010, were as follows:

	2011	2010
FirstEnergy	—%	0.68%
FES	0.53%	0.60%
OE	—%	0.51%
CEI	—%	1.92%
JCP&L	0.51%	—%
Met-Ed	0.51%	0.51%
Penelec	0.51%	0.51%

14. ASSET RETIREMENT OBLIGATIONS

FirstEnergy has recognized applicable legal obligations for AROs and their associated cost primarily for nuclear power plant decommissioning, reclamation of sludge disposal ponds, closure of coal ash disposal sites, underground and above-ground storage tanks, wastewater treatment lagoons and transformers containing PCBs. In addition, FirstEnergy has recognized conditional 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 and the applicable Utilities use an expected cash flow approach to measure the fair value of their nuclear decommissioning AROs.

FirstEnergy, FES and certain Utilities maintain NDTs that are legally restricted for purposes of settling the nuclear decommissioning ARO. The fair values of the decommissioning trust assets as of December 31, 2011 and 2010 were as follows:

	2011	2010
	(In millions)	
FirstEnergy	$2,112	$1,973
FES	1,223	1,146
OE	137	127
TE	83	76
JCP&L	193	182
Met-Ed	310	289
Penelec	166	153

Accounting standards for conditional retirement obligations associated with tangible long-lived assets require recognition of the fair value of a liability for an ARO in the period in which it is incurred if a reasonable estimate can made, even though there may be uncertainty about timing or method of settlement. When settlement is conditional on a future event occurring, it is reflected in the measurement of the liability, not in the recognition of the liability.

The following table summarizes the changes to the ARO balances during 2011 and 2010.

ARO Reconciliation	FirstEnergy[3]	FES	OE	CEI	TE	JCP&L	Met-Ed	Penelec
	(In millions)							
Balance, January 1, 2010	$1,425	$921	$86	$2	$32	$102	$180	$92
Liabilities settled	(11)	—	(10)	—	—	—	—	—
Accretion	93	59	5	—	2	6	13	6
Revisions in estimated cash flows[1]	(100)	(88)	(7)	—	(5)	—	—	—
Balance, December 31, 2010	1,407	892	74	2	29	108	193	98
Liabilities assumed from Allegheny merger	60	—	—	—	—	—	—	—
Liabilities settled[2]	(15)	(1)	(2)	—	—	—	—	—
Accretion	97	59	5	1	2	7	13	7
Revisions in estimated cash flows[4]	(52)	(46)	(6)	—	—	—	—	—
Balance, December 31, 2011	$1,497	$904	$71	$3	$31	$115	$206	$105

(1)

During the second quarter of 2010, studies were completed to reassess the estimated cost of decommissioning the Beaver Valley nuclear generating facilities. The cost studies resulted in a revision to the estimated cash flows associated with the ARO liabilities and reduced the discounted liabilities as shown.

(2) Includes approximately $10 million in reduced ARO liabilities for FirstEnergy as a result of deconsolidation of the Signal Peak joint venture (See Note 8, Variable Interest Entities).

(3) The 2011 changes include activity relating to Allegheny, which merged with FE in February 2011.

(4) During 2011, studies were completed to reassess the estimated cost of decommissioning the Perry and Davis-Besse nuclear generating facilities. The cost studies resulted in revisions to the estimated cash flows associated with the ARO liabilities and reduced the discounted liabilities as shown. These revisions had no significant impact on accretion of the obligations during 2011, as compared to 2010.

15. REGULATORY MATTERS

RELIABILITY MATTERS

Federally-enforceable mandatory reliability standards apply to the bulk electric system and impose certain operating, record-keeping and reporting requirements on the Utilities, FES, AE Supply, FGCO, FENOC, ATSI and TrAIL. The NERC is the ERO designated by FERC to establish and enforce these reliability standards, although NERC has delegated day-to-day implementation and enforcement of these reliability standards to eight regional entities, including RFC. All of FirstEnergy's facilities are located within the RFC region. FirstEnergy actively participates in the NERC and RFC 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 RFC.

FirstEnergy believes that it 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 RFC. Moreover, it is clear that the NERC, RFC 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. 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, the NERC may take with respect to this matter.

On August 23, 2010, FirstEnergy self-reported to RFC 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, RFC issued a notice of enforcement to investigate the incident. FirstEnergy submitted a data response to RFC on September 27, 2010. On July 8, 2011, RFC and Met-Ed signed a settlement agreement to resolve all outstanding issues related to the vegetation encroachment event. The settlement calls for Met-Ed to pay a penalty of $650,000, and for FirstEnergy to perform certain mitigating actions. These mitigating actions include inspecting FirstEnergy's transmission system using LiDAR technology, and reporting the results of inspections, and any follow-up work, to RFC. FirstEnergy was performing the LiDAR work in response to certain other industry directives issued by NERC in 2010. NERC subsequently approved the settlement agreement and, on September 30, 2011, submitted the approved settlement to FERC for final approval. FERC approved the settlement agreement on October 28, 2011. Met-Ed subsequently paid the $650,000 penalty and, on December 31, 2011, RFC sent written notice that this matter has been closed.

In 2011, RFC performed routine compliance audits of parts of FirstEnergy's bulk-power system and generally found the audited systems and process to be in full compliance with all audited reliability standards. RFC will perform additional audits in 2012.

MARYLAND

By statute enacted in 2007, the obligation of Maryland utilities to provide SOS to residential and small commercial customers, in exchange for recovery of their costs plus a reasonable profit, was extended indefinitely. The legislation also established a 5-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 current settlement expires at the end of 2012 will depend on developments with respect to SOS in Maryland over the coming year, 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 proceeding.

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 December 2010, the MDPSC issued an order soliciting comments on a model RFP for solicitation of long-term energy commitments by Maryland electric utilities. PE and numerous other parties filed comments, and on September 29, 2011, the MDPSC issued an order requiring the utilities to issue the RFP crafted by the MDPSC by October 7, 2011. The RFPs were issued by the utilities as ordered by the MDPSC. The order, as amended, indicated that bids were due by January 20, 2012, and that the MDPSC would be the entity evaluating all bids. The Chairman of the MDPSC has stated publicly that several bids were received, but no other information was released. After receipt of further comments from interested parties, including PE, on January 13, 2012, a hearing on whether more generation is needed, irrespective of what bids may have been received, was held on January 31, 2012. There has been no further action on 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 for the PE programs for the period of 2009 to 2015 and would be recovered over that six year period. Meanwhile, after extensive meetings with the MDPSC Staff and other stakeholders, PE's plans for additional and improved programs for the period 2012-2014 were filed on August 31, 2011. The MDPSC held hearings on PE's and the other utilities' plans in October 2011, and on December 22, 2011, issued an order approving Potomac Edison's plan with various modifications and follow-up assignments. On January 23, 2012, PE filed a Request for Rehearing because additional facts not considered by the MDPSC demonstrate, among other things, that conservation voltage reduction program expenditures should be accorded cost recovery through the EmPOWER surcharge, as has been provided for all other EmPOWER programs as opposed to recovery of those expenditures being addressed in a future base rate case as the MDPSC found in its order.

In March 2009, the MDPSC issued an order temporarily suspending 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 collect data on payment plan and related issues and has adopted 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.

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 required to assess each utility's compliance with the new rules, and may assess penalties of up to $25,000 per day per violation. The MDPSC convened a working group of utilities, regulators, and other interested stakeholders to address the topics of the proposed rules. A draft of the rules was filed, along with the report of the working group, on October 27, 2011. Hearings to consider the rules and comments occurred over four days between December 8 and 15, 2011, after which revised rules were sent for legislative review. The proposed rules were published in the

Maryland Register on February 24, 2012, and a deadline of March 26, 2012, was set for the filing of further comments. A further hearing is required before the rules could become final. Separately, on July 7, 2011, the MDPSC adopted draft rules requiring monitoring and inspections for contact voltage. The draft rules were published in September, 2011. After a further hearing in October, 2011, the final rules were re-published and became effective on November 28, 2011.

NEW JERSEY

On September 8, 2011, the Division of Rate Counsel filed a Petition with the NJBPU asserting that it has reason to believe that JCP&L is earning an unreasonable return on its New Jersey jurisdictional rate base. The Division of Rate Counsel requests that the NJBPU order JCP&L to file a base rate case petition so that the NJBPU may determine whether JCP&L's current rates for electric service are just and reasonable. JCP&L filed an answer to the Petition on September 28, 2011, stating, inter alia, that the Division of Rate Counsel analysis upon which it premises its Petition contains errors and inaccuracies, that JCP&L's achieved return on equity is currently within a reasonable range, and that there is no reason for the NJBPU to require JCP&L to file a base rate case at this time. On November 30, 2011, the NJBPU ordered that the matter be assigned to the NJBPU President to act as presiding officer to set and modify the schedule for this matter as appropriate, decide upon motions, and otherwise control the conduct of this case, without the need for full Board approval. The matter is pending and a schedule for further proceedings has not yet been established.

On September 22, 2011, the NJBPU ordered that JCP&L hire a Special Reliability Master, subject to NJBPU approval, to evaluate JCP&L's design, operating, maintenance and performance standards as they pertain to the Morristown, New Jersey underground electric distribution system, and make recommendations to JCP&L and the NJBPU on the appropriate courses of action necessary to ensure adequate reliability and safety in the Morristown underground network. On October 12, 2011, the Special Reliability Master was selected and on January 31, 2012, the project report was submitted to the Company and NJBPU Staff. On February 10, 2012, the NJBPU accepted the report and directed the Staff to present recommendations on March 12, 2012, on actions required by JCP&L to ensure the safe, reliable operation of the Morristown network.

Pursuant to a formal Notice issued by the NJBPU on September 14, 2011, public hearings were held on September 26 and 27, 2011, to solicit public comments regarding the state of preparedness and responsiveness of the local electric distribution companies prior to, during and after Hurricane Irene. By subsequent Notice issued September 28, 2011, additional hearings were held in October 2011. Additionally, the NJBPU accepted written comments through October 31, 2011 related to this inquiry. On December 4, 2011, the NJBPU Division of Reliability and Security issued a Request for Qualifications soliciting bid proposals from qualified consulting firms to provide expertise in the review and evaluation of New Jersey's electric distribution companies' preparation and restoration to Hurricane Irene and the October 2011 snowstorm. Responsive bids were submitted on January 20, 2012, and the report of selected bidder is to be submitted to the NJPBU 120 days from the date the contract is awarded. On December 14, 2011, the NJBPU Staff filed a report of its preliminary findings and recommendations with respect to the electric utility companies' planning and response to Hurricane Irene and the October 2011 snowstorm. The NJBPU has not indicated what additional action, if any, may be taken as a result of information obtained through this process.

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; 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, 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 in 2012. The PUCO issued an Opinion and Order generally approving the Ohio Companies' three-year plan, and the Ohio 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.

Moreover, because the PUCO indicated, when approving the 2009 benchmark request, that it would modify the Ohio 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 May 19, 2011, the PUCO granted the request to reduce the 2010 energy efficiency and peak demand reductions to the level achieved in 2010 for OE, while finding that the motion was moot for CEI and TE. On June 2, 2011, the Ohio Companies filed an application for rehearing to clarify the decision related to CEI and TE. On July 27, 2011, the PUCO denied that application for rehearing, but clarified that CEI and TE could apply for an amendment in the future for the 2010 benchmarks should it be necessary to do so. Failure to comply with the benchmarks or to obtain such an amendment may subject the Ohio Companies to an assessment of a penalty by the PUCO. In addition to approving the programs included in the plan, with only minor modifications, the PUCO authorized the Ohio 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 by the Ohio Companies, Ohio Energy Group and Nucor Steel Marion, Inc. 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 September 7, 2011, the PUCO denied those applications for rehearing. The PUCO also included a new standard for compliance with the statutory energy efficiency benchmarks by requiring electric distribution companies to offer “all available cost effective energy efficiency opportunities” regardless of their level of compliance with the benchmarks as set forth in the statute. On October 7, 2011, the Ohio Companies, the Industrial Energy Users - Ohio, and the Ohio Energy Group filed applications for rehearing, arguing that the PUCO'S new standard is unlawful. The Ohio Companies also asked the PUCO to withdraw its amendment of CEI's and TE's 2010 energy efficiency benchmarks. The PUCO did not rule on the Applications for Rehearing within thirty days, thus denying them by operation of law. On December 30, 2011, the Ohio Companies filed a notice of appeal with the Supreme Court of Ohio, challenging the PUCO's new standard. No procedural schedule has been established.

Additionally, under SB221, electric utilities and electric service companies are required to serve part of their load in 2011 from renewable energy resources equivalent to 1.00% of the average of the KWH they served in 2008-2010; in 2012 from renewable energy resources equivalent to 1.50% of the average of the KWH they served in 2009-2011; and in 2013 from renewable energy resources equivalent to 2.00% of the average of the KWH they served in 2010-2012. 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 SRECs 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. 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. On August 3, 2011, the PUCO granted the Ohio Companies' force majeure request for 2010 and increased their 2011 benchmark by the amount of SRECs generated in Ohio that the Ohio Companies were short in 2010. On September 2, 2011, the Environmental Law and Policy Center and Nucor Steel Marion, Inc. filed applications for rehearing. The Ohio Companies filed their response on September 12, 2011. These applications for rehearing were denied by the PUCO on September 20, 2011, but as part of its Entry on Rehearing the PUCO opened a new docket to review the Ohio Companies' alternative energy recovery rider. Separately, one party has filed a request that the PUCO audit the cost of the Ohio Companies' compliance with the alternative energy requirements and the Ohio Companies' compliance with Ohio law. The PUCO selected auditors to perform a financial and a management audit, and final audit reports are to be filed with the PUCO by May 15, 2012. In August 2011, the Ohio Companies conducted two RFP processes to obtain RECs to meet the statutory benchmarks for 2011 and beyond.

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 customers 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 are continuing 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 the U.S. District Court for the Eastern District of Pennsylvania, which was subsequently amended. The PPUC filed a Motion to Dismiss Met-Ed's and Penelec's Amended Complaint on September 15, 2011. Met-Ed and Penelec filed a Responsive brief in Opposition to the PPUC's Motion to Dismiss on October 11, 2011. 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 each of May 2008, 2009 and 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 DSP 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, (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 provides for potentially significant financial penalties to be assessed upon utilities that fail to achieve the required reductions in consumption and peak demand. Act 129 also required utilities to file a SMIP with the PPUC.

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 became 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 ALJ. On December 15, 2011, the ALJ recommended that the amended plans be approved as proposed, and on January 12, 2012, the Commission approved the plans.
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 September 2010, WP filed an amended EE&C Plan that is less reliant on smart meter deployment, which the PPUC approved in January 2011.
On August 9, 2011, WP filed a petition to approve its Second Amended EE&C Plan. The proposed Second Revised Plan includes measures and a new program and implementation strategies consistent with the successful EE&C programs of Met-Ed, Penelec and Penn that are designed to enable WP to achieve the post-2011 Act 129 EE&C requirements. On January 6, 2012, a Joint Petition for Settlement of all issues was filed by the parties to the proceeding.

The Pennsylvania Companies submitted a preliminary report on July 15, 2011, and a final report on November 15, 2011, in which they reported on their compliance with statutory May 31, 2011, energy efficiency benchmarks. Met-Ed, Penelec and Penn achieved the 2011 benchmarks; however WP has been unable to provide final results because several customers are still accumulating necessary documentation for projects that may qualify for inclusion in the final results. Preliminary numbers indicate that WP did not achieve its 2011 benchmark and it is not known at this time whether WP will be subject to a fine for failure to achieve the benchmark. WP is unable to predict the outcome of this matter or estimate any possible loss or range of loss.

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 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.
Following additional proceedings, 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. A Joint Stipulation with

the OSBA was also filed on March 9, 2011. The PPUC approved the Amended Joint Petition for Full Settlement 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 accounting method utilized by Met-Ed and Penelec. On January 30, 2012, the Commission entered a final order approving Met-Ed's and Penelec's accounting methodology whereby NUG over-collection revenue may be used to reduce non-NUG stranded costs, even if a cumulative NUG stranded cost balance exists.

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 concerning retail markets in Pennsylvania. Met-Ed, Penelec, Penn Power and WP 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. A technical conference was held on August 10, 2011, and a second en banc was held on November 10, 2011, to discuss intermediate steps that can be taken to promote the development of a competitive market. Teleconferences are scheduled through March 2012, with another en banc hearing to be held on March 21, 2012, to explore the future of default service in Pennsylvania following the expiration of the upcoming default service plans on May 31, 2015. Following the issuance of a Tentative Order and comments filed by numerous parties, the Commission entered a final order on December 16, 2011, providing recommendations for components to be included in upcoming default service plans. An intermediate work plan was also presented on December 16, 2011, by Tentative Order, on which initial comments were submitted by Met-Ed, Penelec, Penn and WP on January 17, 2012. FES also submitted comments. Reply comments were submitted on February 1, 2012. It is expected that a final order implementing the intermediate work plan and a long range plan will be presented by the PPUC, both in March 2012.

The PPUC issued a Proposed Rulemaking Order on August 25, 2011, which proposed a number of substantial modifications to the current Code of Conduct regulations that were promulgated to provide competitive safeguards to the competitive retail electric market in Pennsylvania. The proposed changes include, but are not limited to: an EGS may not have the same or substantially similar name as the EDC or its corporate parent; EDCs and EGSs would not be permitted to share office space and would need to occupy different buildings; EDCs and affiliated EGSs could not share employees or services, except certain corporate support, emergency, or tariff services (the definition of "corporate support services" excludes items such as information systems, electronic data interchange, strategic management and planning, regulatory services, legal services, or commodities that have been included in regulated rates at less than market value); and an EGS must enter into a trademark agreement with the EDC before using its trademark or service mark. The Proposed Rulemaking Order, which was published on February 11, 2012, calls for comments to be submitted by March 27, 2012. If implemented these rules could require a significant change in the way FES, Met-Ed, Penelec, Penn and WP do business in Pennsylvania, and could possibly have an adverse impact on their results of operations and financial condition.

In November 2011, Met-Ed, Penelec, Penn and WP filed a Joint Petition for Approval of their Default Service Plan for the period June 1, 2013 through May 31, 2015. The Pennsylvania Companies' direct case was submitted in its entirety on December 20, 2011. Evidentiary hearings are scheduled for April 11-13, 2012, and a final order must be entered by the PPUC by August 17, 2012.

WEST VIRGINIA

In 2009, the West Virginia Legislature enacted the AREPA, 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 10% by 2015, 15% by 2020, and 25% by 2025. In November 2010, the WVPSC issued 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 was issued by the WVPSC in September 2011, which conditionally approved MP's and PE's compliance plan, contingent on the outcome of the resource credits case discussed below.

Additionally, in January 2011, MP and PE filed an application with the WVPSC seeking to certify three facilities as Qualified Energy Resource Facilities. The application was approved and the three facilities are capable of generating renewable credits which will assist the companies in meeting their combined requirements under the AREPA. An annual update filing is due on March 31, 2012. 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 West Virginia. 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. A hearing was held at the WVPSC on August 25 and 26, 2011.

On November 22, 2011, the WVPSC issued an order granting ownership of all RECs produced by the facilities to MP. On December 22, 2011, the WVPSC order was appealed, and the order was stayed pending the outcome of the appeal. MP's brief was filed on February 13, 2012. Should MP be unsuccessful in the appeal, it will have to procure the requisite RECs to comply with AREPA from other sources. MP expects to recover such costs from customers.

In September 2011, MP and PE filed with the WVPSC to recover costs associated with fuel and purchased power (the ENEC) in the amount of $32 million which represents an approximate 3% overall increase in such costs over the past two years, primarily attributable to rising coal prices. The requested increase was partially offset by $2.5 million of synergy savings directly resulting from the merger of FirstEnergy and AE, which closed in February 2011. Under a cost recovery clause established by the WVPSC in 2007, MP and PE customer bills are adjusted periodically to reflect upward or downward changes in the cost of fuel and purchased power. The utilities' most recent request to recover costs for fuel and purchased power was in September 2009. MP and PE entered into a Settlement Agreement related to this matter. The WVPSC issued an order on December 30, 2011, approving the settlement agreement. The approved settlement resulted in an increase of $19.6 million, instead of the requested $32 million, with additional costs to be recovered over time with a carrying charge.

FERC MATTERS

PJM Transmission Rate

In April 2007, FERC issued 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, 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 and higher voltage facilities on a load ratio share basis and, based on this finding, remanded the rate design issue to FERC.

In an order dated January 21, 2010, FERC set the matter for a “paper hearing” and requested 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 load serving entities 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. Other utilities and state commissions supported continued socialization of these costs on a load ratio share basis. This matter is awaiting action by FERC. FirstEnergy cannot predict the outcome of this matter or estimate the possible loss or range of loss.

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 TOs (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 analysis as part of FERC's evaluation of ATSI's proposed transmission rates. Finally, and also on June 30, 2011, the MISO and the MISO TOs filed a competing compliance filing - one that would require ATSI to pay certain charges related to construction and operation of transmission projects within the MISO even though FERC ruled that ATSI cannot pass these costs on to ATSI's customers. ATSI on the one hand, and the MISO and MISO TOs on the other, have submitted subsequent filings - each of which is intended to refute the other's claims. ATSI's compliance filing and request for rehearing, as well as the pleadings that reflect the dispute between ATSI and the MISO/MISO TOs, are currently pending before FERC.

From late April 2011 through June 2011, FERC issued other orders that address ATSI's move into PJM. Also, 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 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. Despite being presented with the issue by FirstEnergy and the MISO, the FERC did not address clearly the question of 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 requested 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. On October 21, 2011, FERC issued its order on rehearing, but that order did not address FirstEnergy's argument directly. FERC ruled instead that if ATSI was subject to MVP charges then ATSI owed these charges upon exit of the MISO. On October 31, 2011, FESC filed a Petition of Review for the FERC's December 2010 order and October 21, 2011 order on rehearing of that order with the U.S. Court of Appeals for the D.C. Circuit. Other parties also filed appeals of those orders and, in November, 2011, the cases were consolidated for briefing and disposition in the U.S. Court of Appeals for the Seventh Circuit. On January 27, 2012, the court ordered the FERC to file a proposed briefing format and schedule on or before March 20, 2012.

On August 3, 2011, FirstEnergy filed a complaint with FERC based on the FERC's December 2010 order. In the complaint, FirstEnergy argued that ATSI perfected the legal and financial requirements necessary to exit MISO before any MVP responsibilities could attach and asked FERC to rule that MISO cannot charge ATSI for MVP costs. On September 2, 2011, MISO, its TOs and other parties, filed responsive pleadings. On September 19, 2011, ATSI filed an answer. On December 29, 2011, the MISO and the MISO TOs filed a new “Schedule 39” to the MISO's tariff. Schedule 39 purports to establish a process whereby the MISO would bill TOs for MVP costs that, according to the MISO, attached to the utility prior to such TOs withdrawal from the MISO. On January 19, 2012, FirstEnergy filed a protest to the MISO's new Schedule 39 tariff.

On February 27, 2012, FERC issued an order (February 2012 Order) dismissing ATSI's August 3, 2011 complaint. In the February 2012 Order, FERC accepted the MISO's Schedule 39 tariff, subject to hearings and potential refund of MVP charges to ATSI. The basis for any subsequent hearing is whether the Schedule 39 tariff was in effect at the time that ATSI exited the MISO. FirstEnergy is evaluating the February 2012 Order and will determine the next steps.

FirstEnergy cannot predict the outcome of these proceedings or estimate the possible loss or range of loss.

FirstEnergy Companies' PJM Underfunding FTR Contract Complaint

On December 28, 2011, FES and AE Supply filed a complaint with FERC against PJM challenging the ongoing underfunding of FTR contracts, which exist to hedge against transmission congestion in the day-ahead markets. The underfunding is a result of PJM's practice of using the funds that are intended to pay the holders of FTR contracts to pay instead for congestion costs that occur in the real time markets. Underfunding of the FTR contracts resulted in losses of approximately $35 million to FES and AE Supply in the 2010-2011 Delivery Year. To date, losses for the 2011-2012 Delivery Year are estimated to be approximately $6 million.

On January 13, 2012, PJM filed comments that describe changes to the PJM tariff that, if adopted, should remedy the underfunding issue. Many parties also filed comments supporting FES' and AE Supply's position. Other parties, generally representatives of end-use customers who will have to pay the charges, filed in opposition to the complaint. The matter is currently pending before FERC. FirstEnergy cannot predict the outcome of this matter or estimate the possible loss or range of loss.

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 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. On June 3, 2011, the California parties requested rehearing of the May 4, 2011 order. The request for rehearing remains pending.

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. That request for rehearing also remains pending. FirstEnergy cannot predict the outcome of either of the above matters or estimate the possible loss or range of loss.

PATH Transmission 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 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 ROE 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% ROE incentive adder and a 0.5% ROE adder for RTO participation. These adders will be applied to the base ROE determined as a result of the hearing. The PATH Companies, Joint Intervenors, Joint Consumer Advocates and FERC staff have agreed to a four year moratorium. A settlement was reached, which reflects a base ROE of 10.4% (plus authorized adders) effective January 1, 2011. Accordingly, the revised ROE was reflected in a revised Projected Transmission Revenue Requirement for 2011 with true-up occurring in 2013. The FirstEnergy portion of the refund for March 1, 2008, through December 31, 2010, is approximately $2 million (inclusive of interest). The refund amount was computed using a base ROE of 10.8% plus authorized adders. On October 7, 2011, PATH and six intervenors submitted to FERC an unopposed settlement agreement. Contemporaneous with this submission, PATH and the six intervenors filed with the Chief ALJ of FERC a joint motion for interim approval and authorization to implement the refund on an interim basis pending issuance of a FERC order acting on the settlement agreement. On October 12, 2011, the motion for interim approval and authorization to implement the refund was granted by the Chief ALJ. On February 16, 2012, FERC approved the settlement agreement and dismissed as moot, in light of its approval of the settlement, PATH's pending request for rehearing of the November 19, 2010 order.

Yards Creek

The Yards Creek Pumped Storage Project is a 400 MW hydroelectric project located in Warren County, New Jersey. JCP&L owns an undivided 50% interest in the project, and operates the project. PSEG Fossil, LLC, a subsidiary of Public Service Enterprise Group, owns the remaining interest in the plant. The project was constructed in the early 1960s, and became operational in 1965.

Authorization to operate the project is by a license issued by the FERC. The existing license expires on February 28, 2013.

In February 2011, JCP&L and PSEG filed a joint application with FERC to renew the license for an additional forty years. The companies are pursuing relicensure through FERC's ILP. Under the ILP, FERC will assess the license applications, issue draft and final Environmental Assessments/Environmental Impact Studies (as required by NEPA), and provide opportunities for intervention and protests by affected third parties. FERC may hold hearings during the two-year ILP licensure period. FirstEnergy expects FERC to issue the new license within the remaining portion of the two-year ILP period. To the extent, however, that the license proceedings extend beyond the February 28, 2013 expiration date for the current license, the current license will be extended yearly as necessary to permit FERC to issue the new license.

Seneca

The Seneca 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 PAD in the license docket.

On November 30, 2010, the Seneca Nation filed its notice of intent to relicense and PADs 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.

On September 12, 2011, FirstEnergy and the Seneca Nation each filed “Revised Study Plan” documents. These documents describe the parties' respective proposals for the scope of the environmental studies that should be performed as part of the relicensing process. On October 11, 2011, FERC Staff issued a letter order that addressed the Revised Study Plans. In the order, FERC Staff approved FirstEnergy's Revised Study Plan, subject to a finding that the Project is located on “aboriginal lands” of the Seneca Nation. Based on this finding, FERC Staff directed FirstEnergy to consult with the Seneca Nation and other parties about the data set, methodology, and modeling of the hydrological impacts of project operations. FirstEnergy is performing the work necessary to develop a study proposal from which to conduct such consultations. The study process will extend through approximately November of 2013.

FirstEnergy cannot predict the outcome of this matter or estimate the possible loss or range of loss.

16. COMMITMENTS, GUARANTEES AND CONTINGENCIES

NUCLEAR INSURANCE

The Price-Anderson Act limits the public liability which can be assessed with respect to a nuclear power plant to $12.6 billion (assuming 104 units licensed to operate) for a single nuclear incident, which amount is covered by: (i) private insurance amounting to $375 million; and (ii) $12.2 billion provided by an industry retrospective rating plan required by the NRC pursuant thereto. Under such retrospective rating plan, in the event of a nuclear incident at any unit in the United States resulting in losses in excess of private insurance, up to $118 million (but not more than

$18 million per unit per year in the event of more than one incident) must be contributed for each nuclear unit licensed to operate in the country by the licensees thereof to cover liabilities arising out of the incident. Based on their present nuclear ownership and leasehold interests, FirstEnergy's maximum potential assessment under these provisions would be $470 million (OE-$40 million, NGC-$408 million, and TE-$22 million) per incident but not more than $70 million (OE-$6 million, NGC-$61 million, and TE-$3 million) in any one year for each incident.

In addition to the public liability insurance provided pursuant to the Price-Anderson Act, FirstEnergy has also obtained insurance coverage in limited amounts for economic loss and property damage arising out of nuclear incidents. FirstEnergy is a member of NEIL, which provides coverage (NEIL I) for the extra expense of replacement power incurred due to prolonged accidental outages of nuclear units. Under NEIL I, FirstEnergy's subsidiaries have policies, renewable yearly, corresponding to their respective nuclear interests, which provide an aggregate indemnity of up to approximately $2.0 billion (OE-$168 million, NGC-$1.7 billion, TE-$90 million) for replacement power costs incurred during an outage after an initial 26-week waiting period. Members of NEIL I pay annual premiums and are subject to assessments if losses exceed the accumulated funds available to the insurer. FirstEnergy's present maximum aggregate assessment for incidents at any covered nuclear facility occurring during a policy year would be approximately $13 million (OE-$1 million, NGC-$12 million, and TE-less than $1 million).

FirstEnergy is insured as to its respective nuclear interests under property damage insurance provided by NEIL to the operating company for each plant. Under these arrangements, up to $2.8 billion of coverage for decontamination costs, decommissioning costs, debris removal and repair and/or replacement of property is provided. FirstEnergy pays annual premiums for this coverage and is liable for retrospective assessments of up to approximately $66 million (OE-$6 million, NGC-$57 million, TE-$2 million, Met Ed, Penelec, and JCP&L-less than $1 million each) during a policy year.

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

The NRC requires nuclear power plant licensees to obtain minimum property insurance coverage of $1.1 billion or the amount generally available from private sources, whichever is less. The proceeds of this insurance are required to be used first to ensure that the licensed reactor is in a safe and stable condition and can be maintained in that condition so as to prevent any significant risk to the public health and safety. Within 30 days of stabilization, the licensee is required to prepare and submit to the NRC a cleanup plan for approval. The plan is required to identify all cleanup operations necessary to decontaminate the reactor sufficiently to permit the resumption of operations or to commence decommissioning. Any property insurance proceeds not already expended to place the reactor in a safe and stable condition must be used first to complete those decontamination operations that are ordered by the NRC. FirstEnergy is unable to predict what effect these requirements may have on the availability of insurance proceeds.

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. 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 credit support to various providers for the financing or refinancing by subsidiaries of costs related to the acquisition of property, plant and equipment. These agreements include provisions for parent guarantees, surety bonds and/or LOCs to be issued by FirstEnergy on behalf of one or more of its subsidiaries. Additionally, certain contracts may contain collateral provisions that are contingent upon either FirstEnergy's or its subsidiaries' credit ratings.

As of December 31, 2011, outstanding guarantees and other assurances aggregated approximately $3.7 billion, consisting primarily of parental guarantees ($0.9 billion), subsidiaries' guarantees ($2.5 billion), surety bonds and LOCs ($0.3 billion).

Most of FirstEnergy's surety bonds are backed by various indemnities common within the insurance industry. Surety bonds and related guarantees of $151 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.

While the types of guarantees discussed above are normally parental commitments for the future payment of subsidiary obligations, subsequent to the occurrence of a senior unsecured credit rating downgrade to below S&P's BBB- and Moody's Baa3 and lower, or a "material adverse event," the immediate posting of collateral or accelerated payments may be required of the subsidiary. As of December 31, 2011, FirstEnergy's exposure to additional credit contingent contractual obligations was $636 million, as shown below:

Collateral Provisions	FES	AE Supply	Utilities	Total
	(In millions)			
Credit rating downgrade to below investment grade [1]	$468	$8	$57	$533
Material adverse event [2]	31	60	12	103
Total	$499	$68	$69	$636

(1) Includes $205 million and $47 million that are also considered accelerations of payment or funding obligations for FES and the Utilities, respectively.

(2) Includes $31 million that is also considered an acceleration of payment or funding obligation at FES.

Certain bilateral non-affiliate contracts entered into by the Competitive Energy Services segment contain margining provisions that require posting of collateral. Based on FES' and AE Supply's power portfolios exposure as of December 31, 2011, FES and AE Supply have posted collateral of $88 million and $1 million, respectively. Depending on the volume of forward contracts and future price movements, higher amounts for margining could be required.

Not included in the preceding information is potential collateral arising from the PSAs between FES or AE Supply and affiliated utilities in the Regulated Distribution Segment. As of December 31, 2011, neither FES nor AE Supply had any collateral posted with their affiliates. In the event of a senior unsecured credit rating downgrade to below S&P's BB- or Moody's Ba3, FES and AE Supply would be required to post $49 million and $24 million, respectively.

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 previously shared ownership in the borrowers with FEV, have provided a guaranty of the borrowers' obligations under the facility. On October 18, 2011, FEV sold a portion of its ownership interest in Signal Peak and Global Rail (see Note 8, Variable Interest Entities). Following the sale, FirstEnergy, WMB Loan Ventures, LLC and WMB Loan Ventures II, LLC, together with Global Mining Group, LLC and Global Holding will continue to guarantee the borrowers' obligations until either the facility is replaced with non-recourse financing (no later than June 30, 2012) or replaced with appropriate recourse financing no earlier than September 4, 2012, that provides for separate guarantees from each owner in proportion with each equity owner's percentage ownership in the joint venture. In addition, FEV, Global Mining Group, LLC and Global Holding, the entities that own direct and indirect equity interests in the borrowers, have pledged those interests to the lenders under the current facility as collateral.

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 or non-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 air emissions from the coal-fired Bruce Mansfield Plant. 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 complaints.

The states of New Jersey and Connecticut filed CAA citizen suits in 2007 alleging NSR violations at the coal-fired 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 or estimate the possible loss or range of loss.

In January 2009, the EPA issued a NOV to GenOn Energy, Inc. alleging NSR violations at the coal-fired Portland Generation Station based on “modifications” dating back to 1986. 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 and Penelec are unable to predict the outcome of this matter or estimate the possible loss or range of loss.

In each of May and September 2010, New Jersey submitted interstate pollution transport petitions seeking to reduce Portland Generating Station air emissions under section 126 of the CAA. Based on the September 2010 petition, the EPA has finalized emissions limits and compliance schedules to reduce SO_2 air emissions by approximately 81% at the Portland Station by January 6, 2015. New Jersey's May 2010 petition is still under consideration by the EPA.

In June 2008, the EPA issued a Notice and Finding of Violation to 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, NYSEG 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, NYSEG, and various current owners of Homer City, including EME Homer City Generation L.P. and affiliated companies, including Edison International. 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. 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.” In October 2011, the Court dismissed all of the claims with prejudice of the U.S. and the Commonwealth of Pennsylvania and the States of New Jersey and New York and all of the claims of the private parties, without prejudice to re-file state law claims in state court, against all of the defendants, including Penelec. In December 2011, the U.S., the Commonwealth of Pennsylvania and the States of New Jersey and New York all filed notices appealing to the Third Circuit Court of Appeals. Penelec believes the claims are without merit and intends to defend itself against the allegations made in these complaints, but, at this time, is unable to predict the outcome of this matter or estimate the loss or possible range of loss. Mission is seeking indemnification from NYSEG and Penelec, the co-owners of Homer City prior to its sale in 1999. On February 13, 2012, the Sierra Club notified the current owner and operator of Homer City, Homer City OL1-OL8 LLC and EME Homer City Generation L.P., that it intends to file a CAA citizen suit regarding its Title V permit and SO_2 emissions from the Homer City Plant.

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 during maintenance outages dating back to 1990 triggered the pre-construction permitting requirements under the PSD and NNSR programs. FGCO also 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 provisions of the CAA. Later in 2009, FGCO also received another information request regarding emission projections for the 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 or estimate the possible loss or range of loss.

In August 2000, AE received an information request pursuant to section 114(a) of the CAA 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 NSR provisions under the CAA, which can require the installation of additional air emission control equipment when a 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 or estimate the possible loss or range of loss.

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 generation units: 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 coal-fired 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 and we are unable to predict the outcome or estimate the possible loss or range of loss.

In September 2007, Allegheny 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 coal-fired Hatfield's Ferry and Armstrong plants in

Pennsylvania and the coal-fired Fort Martin and Willow Island plants in West Virginia.

FirstEnergy intends to vigorously defend against the CAA matters described above but cannot predict their outcomes or estimate the possible loss or range of loss.

State Air Quality Compliance

In early 2006, Maryland passed the Healthy Air Act, which imposes state-wide emission caps on SO_2 and NOx, 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 tenth state to join the RGGI. The Healthy Air Act provides a conditional exemption for the R. Paul Smith coal-fired plant for NOx, SO_2 and mercury, based on a 2006 PJM declaration that the plant is vital to reliability in the Baltimore/Washington DC metropolitan area. Pursuant to the legislation, the MDE passed alternate NOx 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% which began 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. Fourteen RGGI auctions have been held through the end of calendar year 2011. 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. On June 30, 2011, PJM notified MDE that termination of operation at R. Paul Smith would adversely impact the reliability of electrical service in the PJM region absent transmission system upgrades. On January 26, 2012, FirstEnergy announced that R. Paul Smith is among nine coal-fired plants it intends to retire by September 1, 2012, subject to review of reliability impacts by PJM. FirstEnergy is unable to predict the outcome of this matter or estimate the possible loss or range of loss.

In January 2010, the WVDEP issued a NOV for opacity emissions at the Pleasants coal-fired plant. In August 2011, FirstEnergy and WVDEP resolved the NOV through a Consent Order requiring installation of a reagent injection system to reduce opacity by September 2012.

National Ambient Air Quality Standards

The EPA's CAIR requires reductions of NOx and SO_2 emissions in two phases (2009/2010 and 2015), ultimately capping SO_2 emissions in affected states to 2.5 million tons annually and NOx emissions to 1.3 million tons annually. In 2008, the U.S. Court of Appeals for the District of Columbia 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 CSAPR, to replace CAIR, requiring reductions of NOx and SO_2 emissions in two phases (2012 and 2014), ultimately capping SO_2 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. On February 21, 2012, the EPA revised certain CASPR state budgets (for Florida, Louisiana, Michigan, Mississippi, Nebraska, New Jersey, New York, Texas, and Wisconsin and new unit set-asides in Arkansas and Texas), certain generating unit allocations (for some units in Alabama, Indiana, Kansas, Kentucky, Ohio and Tennessee) for NOx and SO_2 emissions and delayed from 2012 to 2014 certain allowance penalties that could apply with respect to interstate trading of NOx and SO_2 emission allowances. On December 30, 2011, CSAPR was stayed by the U.S. Court of Appeals for the District of Columbia Circuit pending a decision on legal challenges raised in appeals filed by various stakeholders and scheduled to be argued before the Court on April 13, 2012. The Court ordered EPA to continue administration of CAIR until the Court resolves the CSAPR appeals. Depending on the outcome of these proceedings and how any final rules are ultimately implemented, FGCO's and AE Supply's future cost of compliance may be substantial and changes to FirstEnergy's operations may result.

During 2011, FirstEnergy recorded pre-tax impairment charges of approximately $6 million ($1 million for FES and $5 million for AE Supply) for NOx emission allowances that were expected to be obsolete after 2011 and approximately $21 million ($18 million for FES and $3 million for AE Supply) for excess SO_2 emission allowances in inventory that it expects will not be consumed in the future.

Hazardous Air Pollutant Emissions

On December 21, 2011, the EPA finalized the MATS to establish emission standards for mercury, hydrochloric acid and various metals for electric generating units. The MATS establishes emission limits for mercury, PM, and HCL for all existing and new coal-fired electric generating units effective in April 2015 and allows averaging of emissions from multiple units located at a single plant. Under the CAA, state permitting authorities can grant an additional compliance year through April 2016, as needed, including instances when necessary to maintain reliability where electric generating units are being closed. In addition, an EPA enforcement policy document contemplates up to an additional year to achieve compliance, through April 2017, under certain circumstances for reliability critical units. On January 26, 2012 and February 8, 2012, FGCO, MP and AE Supply announced the retirement by September 1, 2012 (subject to a reliability review by PJM) of nine coal-fired power plants (Albright, Armstrong, Ashtabula, Bay Shore except for generating unit 1, Eastlake, Lake Shore, R. Paul Smith, Rivesville and Willow Island) with a total capacity of 3,349 megawatts (generating, on average, approximately ten percent of the electricity produced by the companies over the past three years) due to MATS and other environmental regulations. In addition, MP will make a

filing with the WVPSC to provide them with information regarding the retirement of its plants. Depending on how the MATS are ultimately implemented, FirstEnergy's future cost of compliance with MATS may be substantial and other changes to FirstEnergy's operations may result.
On February 24, 2012, PJM notified FirstEnergy of its preliminary analysis of the reliability impacts that may result from closure of the older competitive coal-fired generating units. PJM's preliminary analysis indicated that there would be significant reliability concerns that will need to be addressed. FirstEnergy intends to continue to actively engage in discussions with PJM regarding this notification, including the possible continued operation of certain plants.
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. 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 and report GHG emissions commencing in 2010. 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 of CO_2 equivalents effective January 2, 2011, for existing facilities under the CAA's PSD program.

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 three years with a goal of increasing to $100 billion by 2020; and establishes the “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.A December 2011 U.N. Climate Change Conference in Durban, Africa, established a negotiating process to develop a new post-2020 climate change protocol, called the “Durban Platform for Enhanced Action”. This negotiating process contemplates developed countries, as well as developing countries such as China, India, Brazil, and South Africa, to undertake legally binding commitments post-2020. In addition, certain countries agreed to extend the Kyoto Protocol for a second commitment period, commencing in 2013 and expiring in 2018 or 2020.

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 but failed to answer the question of the extent to which actions for damages based on GHG emissions may remain viable. The Court remanded to the Second Circuit the issue of whether the CAA preempted state common law nuisance actions.

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 CWA 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 CWA 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 CWA 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 CWA 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. 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

CWA 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. On August 5, 2011, EPA issued an information request pursuant to Sections 308 and 311 of the CWA for certain information pertaining to the oil spills and spill prevention measures at FirstEnergy facilities. FirstEnergy responded on October 10, 2011. On February 1, 2012, FirstEnergy executed a tolling agreement with the EPA extending the statute of limitations to July 31, 2012. FGCO does not anticipate any losses resulting from this matter to be material.

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 impoundments at the Albright Station seeking unspecified civil penalties and injunctive relief. The MP filed an answer on July 11, 2011, and a motion to stay the proceedings on July 13, 2011. On January 3, 2012, the Court denied MP's motion to dismiss or stay the CWA citizen suit but without prejudice to re-filing in the future. 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 a 60-Day Notice of Intent required prior to filing a citizen suit under the CWA for alleged failure to obtain a permit to construct the fly ash impoundments at the Albright Plant.

FirstEnergy intends to vigorously defend against the CWA matters described above but, except as indicated above, cannot predict their outcomes or estimate the possible loss or range of loss.

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 coal-fired Hatfield's Ferry 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 estimated costs in excess of $150 million in order to install technology to meet TDS and sulfate limits in the permit or negatively affect its ability to operate the scrubbers as designed. 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. A hearing on the parties' appeals was 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, and has rescheduled a hearing, if necessary, for July 2012. If these settlement discussions are successful, AE Supply anticipates that its obligations will not be material. AE Supply intends to vigorously pursue these issues, but cannot predict the outcome of these appeals or estimate the possible loss or range of loss.

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 CWA 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 the coal-fired Hatfield's Ferry and Mitchell Plants in Pennsylvania and the coal-fired Fort Martin Plant in West Virginia.

In October 2009, the WVDEP issued the water discharge permit for the Fort Martin Plant. Similar to the Hatfield's Ferry water discharge permit, 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 discharge 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 or estimate the possible loss or range of loss.

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 advance 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. Compliance with those regulations could have an adverse impact on FirstEnergy's results of operations and financial condition.

LBR CCB impoundment is expected to run out of disposal capacity for disposal of CCBs from the BMP between 2016 and 2018. BMP is pursuing several CCB disposal options.

Certain of our utilities 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 December 31, 2011, based on estimates of the total costs of cleanup, the Utility Registrants' proportionate responsibility for such costs and the financial ability of other unaffiliated entities to pay. Total liabilities of approximately $106 million (JCP&L - $70 million, TE - $1 million, CEI - $1 million, FGCO - $1 million and FE - $33 million) have been accrued through December 31, 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 an additional expense of $29 million during the second quarter of 2011; $30 million had previously been reserved prior to 2011. FirstEnergy determined that it is reasonably possible that it or its subsidiaries could be found potentially responsible for additional amounts or additional sites, but the possible losses or range of losses cannot be determined or reasonably estimated at this time.

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. In November 2010, the Supreme Court issued an order denying Plaintiffs' motion for leave to appeal. The Court's order effectively ends the attempt to certify the class, and leaves only 9 plaintiffs to pursue their respective individual claims. The matter was referred back to the lower court, which set a trial date for February 13, 2012, for the remaining individual plaintiffs. Plaintiffs have accepted an immaterial amount in final settlement of all matters and the settlement documentation is being finalized for execution by all parties.

Nuclear Plant Matters

Under NRC regulations, FirstEnergy must ensure that adequate funds will be available to decommission its nuclear facilities. As of December 31, 2011, FirstEnergy had approximately $2 billion invested in external trusts to be used for the decommissioning and environmental remediation of Davis-Besse, Beaver Valley, Perry and TMI-2. 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. 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. By letter dated December 29, 2011, FENOC informed the NRC staff that it had increased the parental guarantee to $95 million.

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's failure to begin accepting spent nuclear fuel on January 31, 1998. DOE was required to begin 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. In January 2012, the applicable FirstEnergy affiliates reached a $48 million settlement of these claims.

In August 2010, FENOC submitted an application to the NRC for renewal of the Davis-Besse operating license for an additional twenty years, until 2037. By an order dated April 26, 2011, a NRC 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 from the order granting a hearing on the Davis-Besse license renewal application. On January 10, 2012, intervenors petitioned the ASLB for a new contention on the cracking of the Davis-Besse shield building discussed below.

On October 1, 2011, Davis-Besse was safely shut down for a scheduled outage to install a new reactor vessel head and complete other maintenance activities. The new reactor head, which replaced a head installed in 2002, enhances safety and reliability, and features control rod nozzles made of material less susceptible to cracking. On October 10, 2011, following opening of the building for installation of the new reactor head, a sub-surface hairline crack was identified in one of the exterior architectural elements on the shield building. These elements serve as architectural features and do not have structural significance. During investigation of the crack at the shield building opening, concrete samples and electronic testing found similar sub-surface hairline cracks in most of the building's architectural elements. FENOC's investigation also identified other indications. Included among them were sub-surface hairline cracks in the upper portion of the shield building (above elevation 780') and in the vicinity of the main steam line penetrations. A team of industry-recognized structural concrete experts and Davis-Besse engineers has determined these conditions do not affect the facility's structural integrity or safety.

On December 2, 2011, the NRC issued a CAL which concluded that FENOC provided "reasonable assurance that the shield building remains capable of performing its safety functions." The CAL imposed a number of commitments from FENOC including, submitting a root cause evaluation and corrective actions to the NRC by February 28, 2012, and further evaluations of the shield building. On February 27, 2012, FENOC sent the root cause evaluation to the NRC. Finally, the CAL also stated that the NRC was still evaluating whether the current condition of the shield building conforms to the plant's licensing basis. On December 6, 2011, the Davis-Besse plant returned to service.

By letter dated August 25, 2011, the NRC made a final significance determination (white) associated with a violation that occurred during the retraction of a source range monitor from the Perry reactor vessel. The NRC also placed Perry in the degraded cornerstone column (Column 3) of the NRC's Action Matrix governing the oversight of commercial nuclear reactors. As a result, the NRC staff will conduct several supplemental inspections, culminating in an inspection using Inspection Procedure 95002 to determine if the root cause and contributing causes of risk significant performance issues are understood, the extent of condition has been identified, whether safety culture contributed to the performance issues, and if FENOC's corrective actions are sufficient to address the causes and prevent recurrence.

In light of the impacts of the earthquake and tsunami on the reactors in Fukushima, Japan, the NRC conducted inspections of emergency equipment at U.S. reactors. The NRC also established a Near-Term Task Force to review its processes and regulations in light of the incident, and, on July 12, 2011, the Task Force issued its report of recommendations for regulatory changes. On October 18, 2011, the NRC approved the Staff recommendations, and directed the Staff to implement its near-term recommendations without delay. Ultimately, the adoption of the Staff recommendations on near-term actions is likely to result in additional costs to implement plant modifications and upgrades required by the regulatory process over the next several years, which costs are likely to be material.

On February 16, 2012, the NRC issued a request for information to the licensed operators of 11 nuclear power plants, including Beaver Valley Power Station Units 1 and 2, with respect to the modeling of fuel performance as it relates to "thermal conductivity degradation," which is the potential in older fuel for reduced capacity to transfer heat that could potentially change its performance during various accident scenarios, including loss of coolant accidents. The request for information indicated that this phenomenon has not been accounted for adequately in performance models for the fuel developed by the fuel manufacturer. The NRC is requesting that FENOC provide an analysis to demonstrate that the NRC regulations are being met. Absent that demonstration, the request indicates that the NRC may consider imposing restrictions on reactor operating limits until the issue is satisfactorily resolved.

ICG Litigation

On December 28, 2006, AE Supply and MP filed a complaint in the Court of Common Pleas of Allegheny County, Pennsylvania against ICG, Anker WV, and 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. On August 25, 2011, the Allegheny County Court denied all Motions for Post-Trial relief and the May 2, 2011 verdict became final. On August 26, 2011, ICG posted bond and filed a Notice of Appeal. Briefing on the Appeal is concluded with oral argument expected in May or June of 2012. AE Supply and MP intend to vigorously pursue this matter through appeal.

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. On October 21, 2011, the Court of Appeals rendered its decision affirming the dismissal of the Complaint by the Court of Common Pleas on all counts except for one relating to an allegation of fraud. The Companies timely filed a notice of appeal on December 5, 2011 with the Supreme Court of Ohio challenging this one aspect of the Court of Appeals opinion. The Supreme Court of Ohio has not yet acted on the appeal.

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 under Note 15, Regulatory Matters.

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. In cases where FirstEnergy determines that it is not probable, but reasonably possible that it has a material obligation, it discloses such obligations and the possible loss or range of loss and if such estimate can be made. If it were ultimately determined that FirstEnergy or its subsidiaries have legal liability or are otherwise made subject to liability based on any of the matters referenced above, it could have a material adverse effect on FirstEnergy's or its subsidiaries' financial condition, results of operations and cash flows.

17. TRANSACTIONS WITH AFFILIATED COMPANIES

FES' and the Registrant Utilities' operating revenues, operating expenses, investment income and interest expenses include transactions with affiliated companies. These affiliated company transactions include affiliated company power sales agreements between FirstEnergy's competitive and regulated companies, support service billings, interest on affiliated company notes including the money pools and other transactions.

FirstEnergy's competitive companies provide power through affiliated company power sales to meet a portion of the Ohio and Pennsylvania Companies' POLR and default service requirements. Prior to 2011, Met-Ed and Penelec had a partial requirement PSA with FES to meet a portion of their POLR obligations. The primary affiliated company transactions for FES and the Registrant Utilities during the three years ended December 31, 2011 are as follows:

Affiliated Company Transactions —

2011	FES	OE	CEI	TE	JCP&L	Met-Ed	Penelec
	(In millions)						
Revenues:							
Electric sales to affiliates	$752	$200	$2	$55	$—	$—	$—
Ground lease with ATSI	—	12	7	2	—	—	—
Other	80	1	3	—	—	10	—
Expenses:							
Purchased power from affiliates	252	287	143	94	—	143	208
Fuel	37	—	—	—	—	—	—

Support services	655	130	51	53	90	53	54
Investment Income:							
Interest income from affiliates	—	—	—	9	—	—	—
Interest income from FE	2	—	—	—	—	—	—
Interest Expense:							
Interest expense to affiliates	5	4	10	1	4	3	2
Interest expense to FE	1	—	—	—	1	1	1

Affiliated Company Transactions — 2010	FES	OE	CEI	TE	JCP&L	Met-Ed	Penelec
	(In millions)						
Revenues:							
Electric sales to affiliates	$2,227	$190	$2	$46	$—	$73	$65
Ground lease with ATSI	—	12	7	2	—	—	—
Other	88	1	7	1	—	10	—
Expenses:							
Purchased power from affiliates	371	522	361	181	—	612	643
Fuel	46	—	—	—	—	—	—
Support services	620	128	64	52	94	59	58
Investment Income:							
Interest income from affiliates	—	—	—	12	—	—	—
Interest income from FE	3	—	—	—	—	—	—
Interest Expense:							
Interest expense to affiliates	9	3	14	1	4	2	2
Interest expense to FE	—	—	1	—	—	—	—

Affiliated Company Transactions — 2009	FES	OE	CEI	TE	JCP&L	Met-Ed	Penelec
	(In millions)						
Revenues:							
Electric sales to affiliates	$2,826	$189	$2	$38	$—	$—	$—
Ground lease with ATSI	—	12	7	2	—	—	—
Other	30	1	6	1	—	10	—
Expenses:							
Purchased power from affiliates	222	993	735	393	—	365	342
Fuel	15	—	—	—	—	—	—
Support services	584	141	62	59	91	54	57
Investment Income:							
Interest income from affiliates	—	15	—	17	—	—	—
Interest income from FE	4	1	—	—	—	1	—
Interest Expense:							
Interest expense to affiliates	6	5	17	2	4	3	2
Interest expense to FE	4	1	1	1	—	—	1

FirstEnergy does not bill directly or allocate any of its costs to any subsidiary company. Costs are allocated to FES and the Registrant Utilities from FESC, AESC and FENOC. The majority of costs are directly billed or assigned at no more than cost. The remaining costs are for services that are provided on behalf of more than one company, or costs that cannot be precisely identified and are allocated using formulas developed by FESC, AESC and FENOC. The current allocation or assignment formulas used and their bases include multiple factor formulas: each company's proportionate amount of FirstEnergy's aggregate direct payroll, number of employees, asset balances, revenues, number of customers, other factors and specific departmental charge ratios. Management believes that these allocation methods are reasonable. Intercompany transactions are generally settled under commercial terms within thirty days.
FES and the Utilities are parties to an intercompany income tax allocation agreement with FirstEnergy and its other subsidiaries that provides for the allocation of consolidated tax liabilities. Net tax benefits attributable to FirstEnergy are generally reallocated to the subsidiaries of FirstEnergy that have taxable income. That allocation is accounted for as a capital contribution to the company receiving the tax benefit (see Note 5, Taxes).

18. SUPPLEMENTAL GUARANTOR INFORMATION

As discussed in Note 6, Leases FES has fully and unconditionally guaranteed all of FGCO's obligations under each of the leases associated with Bruce Mansfield Unit 1. The Consolidating Statements of Income for the three years ended

December 31, 2011, Consolidating Balance Sheets as of December 31, 2011, and December 31, 2010, and Condensed Consolidating Statements of Cash Flows for the three years ended December 31, 2011, for FES (parent and guarantor), FGCO and NGC (non-guarantor) are presented below and have been revised, as applicable, for the change in accounting for pensions and OPEB (see Note 1, Organization, Basis of Presentation and Significant Accounting Policies). 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 (see Note 6, Leases). 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.
CONSOLIDATING STATEMENTS OF INCOME

For the Year Ended December 31, 2011	FES	FGCO	NGC	Eliminations	Consolidated
	(In millions)				
REVENUES	$5,387	$2,666	$1,647	$(4,223)	$5,477
OPERATING EXPENSES:					
Fuel	12	1,138	194	—	1,344
Purchased power from affiliates	4,208	5	252	(4,223)	242
Purchased power from non-affiliates	1,378	—	—	—	1,378
Other operating expenses	574	427	578	51	1,630
Pensions and OPEB mark-to-market adjustment	10	68	93	—	171
Provision for depreciation	4	127	150	(6)	275
General taxes	64	37	23	—	124
Impairment of long-lived assets	—	294	—	—	294
Total operating expenses	6,250	2,096	1,290	(4,178)	5,458
OPERATING INCOME (LOSS)	(863)	570	357	(45)	19
OTHER INCOME (EXPENSE):					
Investment income	1	—	56	—	57
Miscellaneous income, including net income from equity investees	924	24	—	(918)	30
Interest expense — affiliates	(2)	(3)	(2)	(1)	(8)
Interest expense — other	(94)	(109)	(64)	64	(203)
Capitalized interest	—	12	23	—	35
Total other income (expense)	829	(76)	13	(855)	(89)
INCOME (LOSS) BEFORE INCOME TAXES	(34)	494	370	(900)	(70)
INCOME TAXES (BENEFITS)	25	(112)	58	18	(11)
NET INCOME (LOSS)	$(59)	$606	$312	$(918)	$(59)

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FIRSTENERGY SOLUTIONS CORP.
CONSOLIDATING STATEMENTS OF INCOME

For the Year Ended December 31, 2010	FES	FGCO	NGC	Eliminations	Consolidated
	(In millions)				
REVENUES	$5,665	$2,435	$1,568	$(3,840)	$5,828
OPERATING EXPENSES:					
Fuel	31	1,200	172	—	1,403
Purchased power from affiliates	3,948	30	232	(3,839)	371
Purchased power from non-affiliates	1,585	—	—	—	1,585
Other operating expenses	314	357	511	48	1,230
Pensions and OPEB mark-to-market adjustment	11	37	59	—	107
Provision for depreciation	3	100	148	(5)	246
General taxes	24	42	28	—	94
Impairment of long-lived assets	—	388	—	—	388
Total operating expenses	5,916	2,154	1,150	(3,796)	5,424
OPERATING INCOME (LOSS)	(251)	281	418	(44)	404
OTHER INCOME (EXPENSE):					
Investment income	5	1	53	—	59
Miscellaneous income (expense), including net income from equity investees	453	1	—	(437)	17
Interest expense — affiliates	—	(8)	(2)	—	(10)
Interest expense — other	(96)	(109)	(65)	64	(206)
Capitalized interest	—	76	16	—	92
Total other income (expense)	362	(39)	2	(373)	(48)
INCOME (LOSS) BEFORE INCOME TAXES	111	242	420	(417)	356
INCOME TAXES (BENEFITS)	(120)	74	153	18	125
NET INCOME (LOSS)	$231	$168	$267	$(435)	$231

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FIRSTENERGY SOLUTIONS CORP.
CONSOLIDATING STATEMENTS OF INCOME

For the Year Ended December 31, 2009	FES	FGCO	NGC	Eliminations	Consolidated
	(In millions)				
REVENUES	$4,390	$2,216	$1,361	$(3,239)	$4,728
OPERATING EXPENSES:					
Fuel	18	973	138	—	1,129
Purchased power from affiliates	3,221	18	222	(3,239)	222
Purchased power from non-affiliates	996	—	—	—	996
Other operating expenses	220	377	497	49	1,143
Pensions and OPEB mark-to-market adjustment	13	56	81	—	150
Provision for depreciation	4	122	142	(6)	262
General taxes	18	45	24	—	87
Impairment of long-lived assets	—	6	—	—	6
Total operating expenses	4,490	1,597	1,104	(3,196)	3,995
OPERATING INCOME (LOSS)	(100)	619	257	(43)	733
OTHER INCOME (EXPENSE):					
Investment income	5	—	120	—	125
Miscellaneous income (expense), including net income from equity investees	585	2	—	(574)	13
Interest expense to affiliates	—	(6)	(4)	—	(10)
Interest expense — other	(44)	(99)	(62)	63	(142)
Capitalized interest	—	50	10	—	60
Total other income (expense)	546	(53)	64	(511)	46
INCOME (LOSS) BEFORE INCOME TAXES	446	566	321	(554)	779
INCOME TAXES (BENEFITS)	(52)	196	117	20	281
NET INCOME (LOSS)	$498	$370	$204	$(574)	$498

FIRSTENERGY SOLUTIONS CORP.
CONSOLIDATING BALANCE SHEETS

As of December 31, 2011	FES	FGCO	NGC	Eliminations	Consolidated
	(In millions)				
ASSETS					
CURRENT ASSETS:					
Cash and cash equivalents	$—	$7	$—	$—	$7
Receivables-					
Customers	424	—	—	—	424
Associated companies	476	643	262	(781)	600
Other	28	20	13	—	61
Notes receivable from associated companies	155	1,346	69	(1,187)	383
Materials and supplies, at average cost	60	232	200	—	492
Derivatives	219	—	—	—	219
Prepayments and other	11	26	1	—	38
	1,373	2,274	545	(1,968)	2,224
PROPERTY, PLANT AND EQUIPMENT:					
In service	84	5,573	5,711	(385)	10,983
Less — Accumulated provision for depreciation	28	1,813	2,449	(180)	4,110
	56	3,760	3,262	(205)	6,873
Construction work in progress	29	195	790	—	1,014
	85	3,955	4,052	(205)	7,887
INVESTMENTS:					
Nuclear plant decommissioning trusts	—	—	1,223	—	1,223
Investment in associated companies	5,716	—	—	(5,716)	—
Other	—	7	—	—	7
	5,716	7	1,223	(5,716)	1,230
DEFERRED CHARGES AND OTHER ASSETS:					
Accumulated deferred income tax benefits	10	307	—	(317)	—
Customer intangibles	123	—	—	—	123
Goodwill	24	—	—	—	24
Property taxes	—	20	23	—	43
Unamortized sale and leaseback costs	—	5	—	75	80
Derivatives	118	—	—	—	118
Other	50	99	3	(62)	90
	325	431	26	(304)	478
	$7,499	$6,667	$5,846	$(8,193)	$11,819
LIABILITIES AND CAPITALIZATION					
CURRENT LIABILITIES:					
Currently payable long-term debt	$1	$411	$513	$(20)	$905
Short-term borrowings-					
Associated companies	1,065	89	32	(1,186)	—
Accounts payable-					
Associated companies	777	228	211	(780)	436
Other	99	121	—	—	220
Accrued taxes	84	42	110	(9)	227
Derivatives	189	—	—	—	189

Other	62	141	16	42	261
	2,277	1,032	882	(1,953)	2,238
CAPITALIZATION:					
Total equity	3,593	3,097	2,587	(5,700)	3,577
Long-term debt and other long-term obligations	1,483	1,905	641	(1,230)	2,799
	5,076	5,002	3,228	(6,930)	6,376
NONCURRENT LIABILITIES:					
Deferred gain on sale and leaseback transaction	—	—	—	925	925
Accumulated deferred income taxes	12	—	510	(236)	286
Asset retirement obligations	—	28	876	—	904
Retirement benefits	56	300	—	—	356
Lease market valuation liability	—	171	—	—	171
Other	78	134	350	1	563
	146	633	1,736	690	3,205
	$7,499	$6,667	$5,846	$(8,193)	$11,819

FIRSTENERGY SOLUTIONS CORP.
CONDENSED CONSOLIDATING BALANCE SHEET

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	181	—	—	—	181
Prepayments and other	48	11	1	—	60
	1,024	898	542	(338)	2,126
PROPERTY, PLANT AND EQUIPMENT:					
In service	99	6,214	5,499	(385)	11,427
Less — Accumulated provision for depreciation	18	2,022	2,173	(175)	4,038
	81	4,192	3,326	(210)	7,389
Construction work in progress	9	520	534	—	1,063
	90	4,712	3,860	(210)	8,452
INVESTMENTS:					
Nuclear plant decommissioning trusts	—	—	1,146	—	1,146
Investment in associated companies	4,773	—	—	(4,773)	—
Other	—	12	—	—	12
	4,773	12	1,146	(4,773)	1,158
DEFERRED CHARGES AND OTHER ASSETS:					
Accumulated deferred income taxes	42	407	—	(449)	—
Customer intangibles	134	—	—	—	134
Goodwill	24	—	—	—	24
Property taxes	—	16	25	—	41
Unamortized sale and leaseback costs	—	10	—	63	73
Derivatives	98	—	—	—	98
Other	22	70	14	(57)	49
	320	503	39	(443)	419
	$6,207	$6,125	$5,587	$(5,764)	$12,155
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	(348)	466
Other	139	102	—	—	241
Accrued taxes	3	36	31	—	70
Derivatives	266	—	—	—	266

Other	52	148	15	37	252
	912	930	928	(331)	2,439
CAPITALIZATION:					
Common stockholder’s equity	3,619	2,495	2,265	(4,760)	3,619
Long-term debt and other long-term obligations	1,519	2,119	793	(1,250)	3,181
	5,138	4,614	3,058	(6,010)	6,800
NONCURRENT LIABILITIES:					
Deferred gain on sale and leaseback transaction	—	—	—	959	959
Accumulated deferred income taxes	—	—	449	(382)	67
Asset retirement obligations	—	27	865	—	892
Retirement benefits	48	237	—	—	285
Lease market valuation liability	—	217	—	—	217
Other	109	100	287	—	496
	157	581	1,601	577	2,916
	$6,207	$6,125	$5,587	$(5,764)	$12,155

FIRSTENERGY SOLUTIONS CORP.
CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS

For the Year Ended December 31, 2011	FES	FGCO	NGC	Eliminations	Consolidated
	(In millions)				
NET CASH PROVIDED FROM (USED FOR) OPERATING ACTIVITIES	$(790)	$926	$702	$(19)	$819
CASH FLOWS FROM FINANCING ACTIVITIES:					
New Financing-					
Long-term debt	—	140	107	—	247
Short-term borrowings, net	1,065	78	32	(1,186)	(11)
Redemptions and Repayments-					
Long-term debt	(136)	(362)	(377)	19	(856)
Short-term borrowings, net	—	—	—	—	—
Other	(9)	(1)	(1)	—	(11)
Net cash used for financing activities	920	(145)	(239)	(1,167)	(631)
CASH FLOWS FROM INVESTING ACTIVITIES:					
Property additions	(24)	(205)	(520)	—	(749)
Proceeds from asset sales	9	590	—	—	599
Sales of investment securities held in trusts	—	—	1,843	—	1,843
Purchases of investment securities held in trusts	—	—	(1,890)	—	(1,890)
Loans to associated companies, net	(120)	(1,157)	105	1,186	14
Customer acquisition costs	(3)	—	—	—	(3)
Other	8	(11)	(1)	—	(4)
Net cash used for investing activities	(130)	(783)	(463)	1,186	(190)
Net change in cash and cash equivalents	—	(2)	—	—	(2)
Cash and cash equivalents at beginning of period	—	9	—	—	9
Cash and cash equivalents at end of period	$—	$7	$—	$—	$7

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FIRSTENERGY SOLUTIONS CORP.
CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS

For the Year Ended December 31, 2010	FES	FGCO	NGC	Eliminations	Consolidated
	(In millions)				
NET CASH PROVIDED FROM (USED FOR) OPERATING ACTIVITIES	$(260)	$380	$685	$(19)	$786
CASH FLOWS FROM FINANCING ACTIVITIES:					
New Financing-					
Long-term debt	—	318	397	—	715
Short-term borrowings, net	—	2	—	—	2
Redemptions and Repayments-					
Long-term debt	(1)	(341)	(449)	19	(772)
Other	—	(1)	(1)	—	(2)
Net cash used for financing activities	(1)	(22)	(53)	19	(57)
CASH FLOWS FROM INVESTING ACTIVITIES:					
Property additions	(9)	(518)	(508)	—	(1,035)
Proceeds from asset sales	—	117	—	—	117
Sales of investment securities held in trusts	—	—	1,927	—	1,927
Purchases of investment securities held in trusts	—	—	(1,974)	—	(1,974)
Loans to associated companies, net	382	52	(26)	—	408
Customer acquisition costs	(113)	—	—	—	(113)
Leasehold improvement payments to associated companies	—	—	(51)	—	(51)
Other	1	—	—	—	1
Net cash provided from (used for) investing activities	261	(349)	(632)	—	(720)
Net change in cash and cash equivalents	—	9	—	—	9
Cash and cash equivalents at beginning of period	—	—	—	—	—
Cash and cash equivalents at end of period	$—	$9	$—	$—	$9

FIRSTENERGY SOLUTIONS CORP.
CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS

For the Year Ended December 31, 2009	FES	FGCO	NGC	Eliminations	Consolidated
	(In millions)				
NET CASH PROVIDED FROM (USED FOR)OPERATING ACTIVITIES	$(20)	$790	$622	$(18)	$1,374
CASH FLOWS FROM FINANCING ACTIVITIES:					
New Financing-					
Long-term debt	1,498	577	363	—	2,438
Equity contributions from parent	—	100	150	(250)	—
Redemptions and Repayments-					
Long-term debt	(2)	(321)	(404)	18	(709)
Short-term borrowings, net	(901)	(248)	(7)	—	(1,156)
Other	(12)	(6)	(3)	—	(21)
Net cash provided from financing activities	583	102	99	(232)	552
CASH FLOWS FROM INVESTING ACTIVITIES:					
Property additions	(4)	(672)	(547)	—	(1,223)
Proceeds from asset sales	—	18	—	—	18
Sales of investment securities held in trusts	—	—	1,379	—	1,379
Purchases of investment securities held in trusts	—	—	(1,406)	—	(1,406)
Loans to associated companies, net	(309)	(219)	(148)	—	(676)
Investment in subsidiary	(250)	—	—	250	—
Other	—	(19)	1	—	(18)
Net cash used for investing activities	(563)	(892)	(721)	250	(1,926)
Net change in cash and cash equivalents	—	—	—	—	—
Cash and cash equivalents at beginning of period	—	—	—	—	—
Cash and cash equivalents at end of period	$—	$—	$—	$—	$—

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19. SEGMENT INFORMATION

With the completion of the AE 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” amounts 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 AE, 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 and FirstEnergy's interest in PATH; TrAIL and PATH were acquired as part of the merger with AE. The transmission assets and operations of JCP&L, Met-Ed, Penelec, MP, PE and WP remained within the Regulated Distribution segment.
- AE Supply, an operator of generation facilities that was acquired as part of the merger with AE, was placed into the Competitive Energy Services segment.

The Regulated Distribution segment distributes electricity through FirstEnergy's ten utility distribution 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 a formulaic rate that recovers costs and a return on investment for capital expenditures in connection with TrAIL, PATH and other projects, revenues from providing transmission services to electric energy providers and power marketers, and revenues from operating a portion of the FirstEnergy transmission system. Its results reflect the net transmission expenses related to the delivery of the respective generation loads.

The Competitive Energy Services segment supplies, through FES and AE Supply, electric power to end-use customers through retail and wholesale arrangements, including competitive retail sales to customers primarily in Ohio, Pennsylvania, Illinois, Michigan, New Jersey and Maryland and the provision of partial POLR and default service for some utilities in Ohio and Pennsylvania. 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. AE Supply together with its consolidated subsidiary, AGC owns, operates and controls the electric generation capacity of 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 Competitive Energy Services segment controls approximately 17,000 MWs of capacity, excluding approximately 2,700 MWs from unregulated plants expected to be closed by September 1, 2012 (see Note 11, Impairment of Long-Lived Assets), and also purchases electricity to meet sales obligations. The segment's net income is primarily derived from 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.
Other/Corporate 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 Utility Registrants do not have separate reportable operating segments.
As described in Note 1, Organization, Basis of Presentation and Significant Accounting Policies, FirstEnergy elected to change its method of recognizing actuarial gains and losses for its defined benefit pension and OPEB plans, and applied this change retrospectively to all periods presented.
Segment Financial Information

For the Years Ended December 31,	Regulated Distribution	Competitive Energy Services (In millions)	Regulated Independent Transmission	Other	Reconciling Adjustments	Consolidated
2011						
External revenues	$10,004	$5,936	$391	$(114)	$(26)	$16,191
Internal revenues	—	1,237	—	—	(1,170)	67
Total Revenues	10,004	7,173	391	(114)	(1,196)	16,258
Depreciation and amortization	943	415	66	26	—	1,450
Investment income	110	56	—	1	(53)	114
Net interest charges	(573)	(298)	(46)	(91)	—	(1,008)
Income taxes	335	222	66	(87)	38	574
Net income	570	377	112	(149)	(41)	869
Total assets	27,477	16,796	2,436	617	—	47,326
Total goodwill	5,551	890	—	—	—	6,441
Property additions	1,066	927	192	93	—	2,278
2010						
External revenues	$9,571	$3,575	$242	$(88)	$(35)	$13,265
Internal revenues	139	2,301	—	—	(2,366)	74
Total Revenues	9,710	5,876	242	(88)	(2,401)	13,339
Depreciation and amortization	1,145	284	47	14	—	1,490
Investment income	102	51	—	(2)	(34)	117
Net interest charges	(500)	(232)	(22)	(104)	13	(845)
Income taxes	338	128	32	(44)	8	462
Net income	553	210	54	(79)	(20)	718
Total assets	22,160	11,320	1,064	987	—	35,531
Total goodwill	5,551	24	—	—	—	5,575
Property additions	681	1,159	64	59	—	1,963
2009						
External revenues	$10,916	$1,928	$223	$(82)	$(29)	$12,956
Internal revenues	—	2,843	—	—	(2,826)	17
Total Revenues	10,916	4,771	223	(82)	(2,855)	12,973
Depreciation and amortization	1,432	279	50	15	—	1,776

Investment income	141	121	—	4	(62)	204
Net interest charges	(478)	(174)	(19)	(345)	38	(978)
Income taxes	243	305	26	(140)	(250)	184
Net income	335	446	39	(209)	245	856
Total assets	22,663	10,668	974	749	—	35,054
Total goodwill	5,551	24	—	—	—	5,575
Property additions	718	1,412	32	41	—	2,203

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

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reporting primarily consist of interest expense related to holding company debt, corporate support services revenues and expenses and elimination of intersegment transactions.

Electricity sales during the years ended 2011, 2010 and 2009, were $15,117 million, $12,523 million and $12,032 million, respectively.

20. SUMMARY OF QUARTERLY FINANCIAL DATA (UNAUDITED)

The following summarizes certain consolidated operating results by quarter for 2011 and 2010. All periods presented have been revised for the change in accounting for Pensions and OPEB as described further in Note 1, Organization, Basis of Presentation and Significant Accounting Policies.

FirstEnergy

CONSOLIDATED STATEMENTS OF INCOME

(In millions, except per share amounts)	2010				2011		
As Reported	Mar. 31	June 30	Sept. 30	Dec. 31	Mar. 31	June 30	Sept. 30
Revenues	$3,299	$3,139	$3,728	$3,173	$3,576	$4,060	$4,719
Other operating expense	701	673	738	738	1,008	1,098	1,024
Pensions and OPEB mark-to-market adjustment	—	—	—	—	—	—	—
Provision for depreciation	193	190	182	181	220	282	292
Impairment of long-lived assets	—	—	292	92	25	7	9
Operating Income	416	526	415	448	315	486	1,022
Income before income taxes	260	390	294	298	123	272	820
Income taxes	111	134	119	118	78	101	311
Net Income	149	256	175	180	45	171	509
Earnings available to FirstEnergy Corp.	155	265	179	185	50	181	511
Earnings per share of common stock-							
Basic	$0.51	$0.87	$0.59	$0.61	$0.15	$0.43	$1.22
Diluted	$0.51	$0.87	$0.59	$0.60	$0.15	$0.43	$1.22

	2010				2011		
Effect of Change	Mar. 31	June 30	Sept. 30	Dec. 31	Mar. 31	June 30	Sept. 30
Revenues	$—	$—	$—	$—	$—	$—	$—
Other operating expense	(39)	(39)	(39)	(37)	(40)	(40)	(40)
Pensions and OPEB mark-to-market adjustment	—	—	—	190	—	—	—
Provision for depreciation	5	5	5	7	5	5	5
Impairment of long-lived assets	—	—	3	1	—	—	—
Operating Income	34	34	31	(161)	35	35	35
Income before income taxes	34	34	31	(161)	35	35	35
Income taxes	13	13	13	(59)	13	13	14
Net Income	21	21	18	(102)	22	22	21
Earnings available to FirstEnergy Corp.	21	21	18	(102)	22	22	21
Earnings per share of common stock-							
Basic	$0.07	$0.07	$0.06	$(0.34)	$0.06	$0.05	$0.05
Diluted	$0.06	$0.06	$0.06	$(0.33)	$0.06	$0.05	$0.05

	2010				2011			
As Revised	Mar. 31	June 30	Sept. 30	Dec. 31	Mar. 31(1)	June 30	Sept. 30	Dec. 31

Revenues	$3,299	$3,139	$3,728	$3,173	$3,576	$4,060	$4,719	$3,903
Other operating expense	662	634	699	701	968	1,058	984	899
Pensions and OPEB mark-to-market adjustment	—	—	—	190	—	—	—	507
Provision for depreciation	198	195	187	188	225	287	297	312
Impairment of long-lived assets	—	—	295	93	25	7	9	372
Operating Income	450	560	446	287	350	521	1,057	(230)
Income before income taxes	294	424	325	137	158	307	855	123
Income taxes	124	147	132	59	111	114	325	24
Net Income	170	277	193	78	47	193	530	99
Earnings available to FirstEnergy Corp.	176	286	197	83	52	203	532	98
Earnings per share of common stock-								
Basic	$0.58	$0.94	$0.65	$0.27	$0.15	$0.48	$1.27	$0.23
Diluted	$0.57	$0.93	$0.65	$0.27	$0.15	$0.48	$1.27	$0.23

(1) Reflects a $20 million ($0.06 per basic and diluted share of common stock) increase to income taxes related to an Allegheny purchase accounting adjustment identified in the fourth quarter of 2011. FirstEnergy will revise its 2011 quarter filings prospectively when the corresponding 2012 quarters are filed.

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CONSOLIDATED STATEMENTS OF INCOME

(In millions)	2010				2011		
As Reported	Mar. 31	June 30	Sept. 30	Dec. 31	Mar. 31	June 30	Sept. 30
Revenues	$1,388.0	$1,326.0	$1,589.0	$1,525.0	$1,391.0	$1,292.0	$1,467.0
Other operating expense	305.0	304.0	308.0	363.0	496.0	429.0	405.0
Pensions and OPEB mark-to-market adjustment	—	—	—	—	—	—	—
Provision for depreciation	63.0	63.0	60.0	57.0	68.0	68.0	