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	(E) Denotes executive officer of FES	(J) Denotes executive officer of MP, PE and WP
(A) Denotes executive officer of FE	(F) Denotes executive officer of FENOC	(K) Denotes executive officer of TrAIL
(B) Denotes executive officer of FESC	(G) Denotes executive officer of AE	(L) Position effective January 1, 2012
(C) Denotes executive officer of OE, CEI and TE	(H) Denotes executive officer of AESC	(M) Retired on December 31, 2011
(D) Denotes executive officer of Met-Ed, Penelec and Penn	(I) Denotes executive officer of AGC	

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

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(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

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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

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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:

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

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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	Competitive Energy Services	Regulated Independent Transmission	Other and Reconciling Adjustments	FirstEnergy Consolidated
	(In millions)				
Revenues:					
External Electric	$9,271	$3,252	$—	$—	