JERSEY CENTRAL POWER & LIGHT CO
Form 10-K
February 25, 2013

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, 2012
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
1-3141	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

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
Jersey Central Power & Light Company	Common Stock, $10.00 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, and Jersey Central Power & Light 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, and Jersey Central Power & Light 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 and Jersey Central Power & Light 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 and Jersey Central Power & Light 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 and Jersey Central Power & Light Company

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

Large Accelerated Filer þ	FirstEnergy Corp.
Accelerated Filer o	N/A
Non-accelerated Filer (Do not check if a smaller reporting company) þ	FirstEnergy Solutions Corp., Ohio Edison Company and Jersey Central Power & Light 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 and Jersey Central Power & Light 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., $20,518,723,171 as of June 30, 2012; and for all other registrants, none.

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

CLASS	OUTSTANDING AS OF JANUARY 31, 2013
FirstEnergy Corp., $.10 par value	418,216,437
FirstEnergy Solutions Corp., no par value	7
Ohio Edison Company, no par value	60
Jersey Central Power & Light Company, $10 par value	13,628,447

FirstEnergy Corp. is the sole holder of FirstEnergy Solutions Corp., Ohio Edison Company and Jersey Central Power & Light Company common stock.

DOCUMENT	PART OF FORM 10-K INTO WHICH DOCUMENT IS INCORPORATED
Proxy Statement for 2013 Annual Meeting of Shareholders to be held May 21, 2013	Parts II and III

This combined Form 10-K is separately filed by FirstEnergy Corp., FirstEnergy Solutions Corp., Ohio Edison Company and Jersey Central Power & Light 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 and Jersey Central Power & Light 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, in general, and the retail sales market in particular.
- 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 and pending rate cases.
- The uncertainties of various cost recovery and cost allocation issues resulting from ATSI's realignment into PJM.
- Economic or weather conditions affecting future sales and margins.
- Regulatory outcomes associated with Hurricane Sandy.
- Changing energy, capacity and commodity market prices including, but not limited to, coal, natural gas and oil, and availability and their impact on retail margins.
- Financial derivative reforms that could increase our liquidity needs and collateral costs.
- The continued ability of our 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 discharge, water intake and coal combustion residual regulations, the potential impacts of CAIR, and any laws, rules or regulations that ultimately replace CAIR, and the effects of the EPA's MATS rules including our estimated costs of compliance.
- 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 deactivate or idle certain generating units).
- The uncertainties associated with the deactivation of certain older unscrubbed regulated and competitive fossil units, including the impact on vendor commitments, and the timing thereof as they relate to, among other things, the RMR arrangements and the reliability of the transmission grid.
- 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 or as a result of the incident at Japan's Fukushima Daiichi Nuclear Plant).
- Adverse legal decisions and outcomes related to ME's and PN's ability to recover certain transmission costs through their TSC riders.
- The impact of future changes to the operational status or availability of our generating units.
- The risks and uncertainties associated with litigation, arbitration, mediation and like proceedings, including, but not limited to, any such proceedings related to vendor commitments.
- Replacement power costs being higher than anticipated or inadequately hedged.
- The ability to comply with applicable state and federal reliability standards and energy efficiency and peak demand reduction mandates.
- Changes in customers' demand for power, including but not limited to, changes resulting from the implementation of state and federal energy efficiency and peak demand reduction mandates.
- The ability to accomplish or realize anticipated benefits from strategic and financial goals including, but not limited to, the ability to successfully complete the proposed West Virginia asset transfer and to improve our credit metrics.
- Our ability to improve electric commodity margins and the impact of, among other factors, the increased cost of fuel and fuel transportation on such margins.
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The ability to experience growth in the Regulated Distribution segment and to continue to successfully implement our direct retail sales strategy in the Competitive Energy Services segment.

- Changing market conditions that could affect the measurement of liabilities and the value of assets held in our NDTs, pension trusts and other trust funds, and cause us and our 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 our financing plans, the cost of such capital and overall condition of the capital and credit markets affecting us and our subsidiaries.
- Actions that may be taken by credit rating agencies that could negatively affect us and our subsidiaries' access to financing, increase the costs thereof, and increase requirements to post additional collateral to support outstanding commodity positions, LOCs and other financial guarantees.
- Changes in national and regional economic conditions affecting us, our subsidiaries and our major industrial and commercial customers, and other counterparties including fuel suppliers, with which we do business.
- Issues concerning the stability of domestic and foreign financial institutions and counterparties with which we do business.
- The risks and other factors discussed from time to time in our 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.

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GLOSSARY OF TERMS

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

AE	Allegheny Energy, Inc., a Maryland utility holding company that merged with a subsidiary of FirstEnergy on February 25, 2011
AESC	Allegheny Energy Service Corporation, a subsidiary of AE
AE Supply	Allegheny Energy Supply Company, LLC, an unregulated generation subsidiary of AE
AGC	Allegheny Generating Company, a generation subsidiary of AE Supply
Allegheny	Allegheny Energy, Inc., together with its consolidated subsidiaries
Allegheny Utilities	MP, PE and WP
ATSI	American Transmission Systems, Incorporated, formerly a direct subsidiary of FE that became a subsidiary of FET in April 2012, which owns and operates transmission facilities.
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
FET	FirstEnergy Transmission, LLC, formerly known as Allegheny Energy Transmission, LLC, a subsidiary of AE, which is the parent of ATSI and TrAIL and has a joint venture in PATH.
FEV	FirstEnergy Ventures Corp., which invests in certain unregulated enterprises and business ventures
FG	FirstEnergy Generation, LLC, 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 Pinesdale LLC
Global Rail	A subsidiary of Global Holding that owns coal transportation operations near Roundup, Montana
GPU	GPU, Inc., former parent of JCP&L, ME and PN, that merged with FirstEnergy on November 7, 2001
JCP&L	Jersey Central Power & Light Company, a New Jersey electric utility operating subsidiary
ME	Metropolitan Edison Company, a Pennsylvania electric utility operating subsidiary
Merger Sub	Element Merger Sub, Inc., a Maryland corporation and a wholly owned subsidiary of FirstEnergy
MP	Monongahela Power Company, a West Virginia electric utility operating subsidiary of AE
NG	FirstEnergy Nuclear Generation, LLC, 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-WV	PATH West Virginia Transmission Company, LLC
PE	The Potomac Edison Company, a Maryland electric utility operating subsidiary of AE
Penn	Pennsylvania Power Company, a Pennsylvania electric utility operating subsidiary of OE

Pennsylvania Companies	ME, PN, Penn and WP
PN	Pennsylvania Electric Company, a Pennsylvania electric utility operating subsidiary
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	An indirect subsidiary of Global Holding 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 FET, which owns and operates transmission facilities
Utilities	OE, CEI, TE, Penn, JCP&L, ME, PN, MP, PE and WP
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:

AEP	American Electric Power Company, Inc.
ALJ	Administrative Law Judge
AMP	American Municipal Power, Inc.
AMT	Alternative Minimum Tax

GLOSSARY OF TERMS, Continued

Anker WV	Anker West Virginia Mining Company, Inc.
Anker Coal	Anker Coal Group, Inc.
AOCI	Accumulated Other Comprehensive Income
ARO	Asset Retirement Obligation
ARR	Auction Revenue Right
ASLB	Atomic Safety and Licensing Board
BGS	Basic Generation Service
BTU	British Thermal Units
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
CAL	Confirmatory Action Letter
CBP	Competitive Bid Process
CCB	Coal Combustion By-products
CDWR	California Department of Water Resources
CERCLA	Comprehensive Environmental Response, Compensation, and Liability Act of 1980
CFTC	Commodity Futures Trading Commission
CO_2	Carbon Dioxide
CSAPR	Cross-State Air Pollution Rule
CWA	Clean Water Act
CWIP	Construction Work in Progress
DCPD	Deferred Compensation Plan for Outside Directors
DCR	Delivery Capital Recovery
DOE	United States Department of Energy
DOJ	United States Department of Justice
DSP	Default Service Plan
EBO	Early Buyout Option
EDC	Electric Distribution Company
EDCP	Executive Deferred Compensation Plan
EE&C	Energy Efficiency and Conservation
EGS	Electric Generation Supplier
EIS	Environmental Impact Statement
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 of America
GHG	Greenhouse Gases
GWH	Gigawatt-hour
HCL	Hydrochloric Acid

IBEW	International Brotherhood of Electrical Workers
ICE	IntercontinentalExchange, Inc.
ICG	International Coal Group Inc.
ILP	Integrated License Application Process

GLOSSARY OF TERMS, Continued

IRS	Internal Revenue Service
IT	Information Technology
kV	Kilovolt
KWH	Kilowatt-hour
LBR	Little Blue Run
LCAPP	Long-Term Capacity Agreement Pilot Program
LITE	Local Infrastructure and Transmission Enhancement
LOC	Letter of Credit
LSE	Load Serving Entity
LTIP	Long-Term Incentive Plan
MATS	Mercury and Air Toxics Standards
MDPSC	Maryland Public Service Commission
MISO	Midwest Independent Transmission System Operator, Inc.
Moody’s	Moody’s Investors Service, Inc.
MOPR	Minimum Offer Price Rule
MOU	Memorandum of Understanding
MTEP	MISO Regional Transmission Expansion Plan
MVP	Multi-value Project
MW	Megawatt
MWH	Megawatt-hour
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
NMB	Non-Market Based
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
OCC	Ohio Consumers' Counsel
OCI	Other Comprehensive Income
OPEB	Other Post-Employment Benefits
OPEIU	Office and Professional Employees International Union
OTC	Over The Counter
OTTI	Other Than Temporary Impairments
OVEC	Ohio Valley Electric Corporation
PA DEP	Pennsylvania Department of Environmental Protection
PCB	Polychlorinated Biphenyl
PCRB	Pollution Control Revenue Bond
PJM	PJM Interconnection LLC
PM	Particulate Matter

POLR	Provider of Last Resort
PPUC	Pennsylvania Public Utility Commission
PSA	Power Supply Agreement
PSD	Prevention of Significant Deterioration

GLOSSARY OF TERMS, Continued

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 Corporation
RFP	Request for Proposal
RGGI	Regional Greenhouse Gas Initiative
RMR	Reliability Must-Run
RPM	Reliability Pricing Model
RTEP	Regional Transmission Expansion Plan
RTO	Regional Transmission Organization
S&P	Standard & Poor's Ratings Service
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SAMA	Severe Accident Mitigation Alternatives
SB221	Amended Substitute Senate Bill 221
SBC	Societal Benefits Charge
SEC	United States Securities and Exchange Commission
SF_6	Sulfur Hexaflouride
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
TMI-2	Three Mile Island Unit 2
TSC	Transmission Service Charge
UWUA	Utility Workers Union of America
VIE	Variable Interest Entity
VSCC	Virginia State Corporation Commission
WVDEP	West Virginia Department of Environmental Protection
WVPSC	Public Service Commission of West Virginia

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), JCP&L, ME, PN, AE and its principal subsidiaries (AE Supply, AGC, MP, PE, WP, FET and its principal subsidiaries (ATSI, TrAIL and PATH), and AESC), FES and its principal subsidiaries (FG and NG), and FESC. In addition, FirstEnergy holds all of the outstanding common stock of other direct subsidiaries including: FirstEnergy Properties, Inc., FEV, FENOC, FELHC, Inc., and GPU Nuclear, Inc.

Subsidiaries

FirstEnergy's revenues are primarily derived from electric service provided by its utility operating subsidiaries (OE, CEI, TE, Penn, ATSI, JCP&L, ME, PN, 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 13.4 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 1.6 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 in the PJM Region. ATSI plans, operates, and maintains its transmission system in accordance with NERC reliability standards, and other applicable regulatory requirements. In addition, 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.

ME 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. ME 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. ME complies with the regulations, orders, policies and practices prescribed by the SEC, FERC and PPUC.

PN 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. PN 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. PN, as lessee of the property of its subsidiary, The Waverly Electric Light & Power Company, also serves customers in the Waverly, New York vicinity. PN complies with the regulations, orders, policies and practices prescribed by the SEC, FERC, NYPSC and PPUC.

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 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.

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 generation, 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. As of December 31, 2012, MP owned or contractually controlled 2,076 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 PE 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.

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.

TrAIL was organized under the laws of the State of Maryland and the Commonwealth of Virginia in 2006. TrAIL was formed to finance, construct, own, operate and maintain high-voltage transmission facilities in the PJM Region and has several transmission facilities in operation at the present time including a 500kV transmission line extending approximately 150 miles from southwestern Pennsylvania through West Virginia to a point of interconnection with Virginia Electric and Power Company in northern Virginia. TrAIL plans, operates and maintains its transmission system and facilities in accordance with NERC reliability standards, and other applicable regulatory requirements. In addition, TrAIL complies with the regulations, orders, policies and practices prescribed by the SEC, FERC, and applicable state regulatory authorities.

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

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

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

Reference is made to Note 18, Segment Information, of the Combined Notes to Consolidated Financial Statements for information regarding FirstEnergy's reportable segments, which information is incorporated herein by reference.

Competitive and Regulated Generation

As of September 1, 2012, the following coal-fired power plants, which collectively include sixteen generating units, were deactivated: Albright, Armstrong, Bay Shore Units 2-4, Eastlake Units 4-5, R. Paul Smith, Rivesville and Willow Island. Five additional generating units, Ashtabula, Eastlake Units 1-3, and Lake Shore will remain active pursuant to RMR arrangements with PJM until their anticipated deactivation, which is expected in the spring of 2015.

FirstEnergy’s generating portfolio consists of 20,372 MW of diversified capacity (Competitive — 18,096 MW and Regulated — 2,276 MW). Of the generation asset portfolio, including approximately 12,120 MW (59.5%), consist of coal-fired capacity; 3,991 MW (19.6%) consist of nuclear capacity; 1,832 MW (9.0%) consist of hydroelectric capacity; 1,745 MW (8.6%) consist of oil and natural gas units; 496 MW (2.4%) consist of wind and solar facilities; and 188 MW (0.9%) consist of capacity entitlements to output from generation assets 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, 11,540 MW consist of FES' facilities that are operated by FENOC and FG (including entitlements from OVEC, wind and solar power arrangements), except for portions of certain facilities that are subject to the sale and leaseback arrangements with non-affiliates referred to above. The corresponding output of these arrangements is available to FES through

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power sale agreements, and are owned directly by NG and FG, respectively. Another 6,556 MW of the Competitive portfolio consists of AE Supply's facilities, including 660 MW from AGC's Bath County, Virginia hydroelectric facility that AE Supply partially owns and 67 MW of AE Supply's 3.01% entitlement from OVEC's generation output. FES' generating facilities are concentrated primarily in Ohio and Pennsylvania and AE Supply's generating facilities are primarily located in Pennsylvania, West Virginia, Virginia and Ohio.

Within the Regulated portfolio, 200 MW consist of JCP&L's 50% ownership interest in the Yards Creek hydroelectric facility in New Jersey; 2,065 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 MP's 0.49% entitlement from OVEC's generation output.

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 it 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 competitive retail electric suppliers 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 their public utility affiliates. In addition, if FES, AE Supply or any of their subsidiaries were to engage in the construction of significant new generation facilities in any of those states, they would also be subject to state siting authority.

Federal Regulation

With respect to their wholesale services and rates, the Utilities, AE Supply, ATSI, AGC, FES, FG, NG, PATH and TrAIL are subject to regulation by FERC. Under the FPA, FERC regulates rates for interstate sales at wholesale, transmission of electric power, accounting and other matters, including construction and operation of hydroelectric projects. FERC regulations require ATSI, JCP&L, ME, MP, PE, PN, WP and TrAIL to provide open access transmission service at FERC-approved rates, terms and conditions. Transmission facilities of ATSI, JCP&L, ME, MP, PE, PN, WP and TrAIL are subject to functional control by PJM and transmission service using their transmission facilities is provided by PJM under its open access transmission tariff. See FERC Matters below.

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, ME, PN, 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 FERC; although major wholesale purchases and sales remain subject to regulation by the relevant state commissions. Moreover, as a condition to selling electricity on a wholesale basis at market-based rates, OE, CEI, TE, Penn, JCP&L, ME, PN, MP, WP and PE, like all other entities granted market-based rate authority, must file electronic quarterly reports with FERC listing their sales transactions for the prior quarter. AE Supply, FES, FG and NG each have been authorized by FERC to sell wholesale power in interstate commerce and have a market-based tariff on file with 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, FERC has granted AE Supply, FES, FG and NG 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, FERC also granted AE Supply, FES, FG and NG 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, FG and NG, like all other entities granted market-based rate authority, must file electronic quarterly reports with FERC, listing their sales transactions for the prior quarter.

The nuclear generating facilities owned and leased by NG and OE, and operated by FENOC, 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 NG’s plants. See Nuclear Regulation below.

Regulatory Accounting

The Utilities, ATSI, PATH and TrAIL recognize, as regulatory assets, costs which FERC, PUCO, PPUC MDPSC, WVPSC and NJBPU, as applicable, 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. Based on current ratemaking procedures, the Utilities, ATSI, PATH and TrAIL continue to collect cost-based rates for their transmission and distribution services and, in the case of PATH, for its abandoned plant, which remains 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 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 Matters

Federally-enforceable mandatory reliability standards apply to the bulk electric system and impose certain operating, record-keeping and reporting requirements on the Utilities, FES, AE Supply, FG, FENOC, ATSI and TrAIL. 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 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.

Maryland Regulatory Matters

PE provides SOS pursuant to a combination of settlement agreements, MDPSC orders and regulations, and statutory provisions. SOS supply is competitively procured in the form of rolling contracts of varying lengths through periodic auctions that are overseen by the MDPSC and a third party monitor. Although settlements with respect to residential SOS for PE customers expired on December 31, 2012, by statute, service continues in the same manner unless changed by order of the MDPSC. The settlement provisions relating to non-residential SOS have also expired, however, by MDPSC order, the terms of service remain in place unless PE requests or the MDPSC orders a change. PE recovers its costs plus a return for providing SOS.

The Maryland legislature in 2008 adopted a statute codifying the EmPOWER Maryland goals to reduce electric consumption by 10% and reduce electricity demand by 15%, in each case by 2015. Expenditures were originally estimated to be approximately $101 million for the PE programs for the period of 2009 to 2015 and would have been recovered over that six-year period. Maryland law only allows for the utility to recover lost distribution revenue attributable to energy efficiency or demand reduction programs through a base rate case proceeding, and to date such recovery has not been sought or obtained by PE. Meanwhile, after extensive meetings with the MDPSC Staff and other stakeholders, on August 31, 2011, PE filed a new comprehensive plan that includes additional and improved programs for the period 2012-2014. The plan is expected to cost approximately $66 million over the three-year period. On December 22, 2011, the MDPSC issued an order approving PE's plan with various modifications and follow-up assignments.

Pursuant to a bill passed by the Maryland legislature in 2011, the MDPSC proposed rules, based on the product of a working group of utilities, regulators and other interested stakeholders, that create specific requirements related to a utility's obligation to address service interruptions, downed wire response, customer communication, vegetation management, equipment inspection, and annual reporting. The bill requires that the MDPSC 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 will be required to assess each utility's compliance with the new rules, and may assess penalties of up to $25,000 per day, per violation. At a hearing on April 17, 2012, the MDPSC approved re-publication of the rules as final. The new rules set utility-specific SAIDI and SAIFI targets for 2012-2015; prescribe detailed tree-trimming requirements, outage restoration and downed wire response deadlines; and impose other reliability and customer satisfaction requirements. PE has advised the MDPSC that compliance with the new rules is expected to increase costs by approximately $106 million over the period 2012-2015.

Following a "derecho" storm through the region on June 29, 2012, the MDPSC convened a new proceeding to consider matters relating to the electric utilities' performance in responding to the storm. Hearings on the matter were conducted in September 2012. Concurrently, Maryland's governor convened a special panel to examine possible ways to improve the resilience of the electric distribution system. On October 3, 2012, that panel issued a report calling for various measures including: acceleration and expansion of some of the requirements contained in the reliability standards that the MDPSC approved on April 17, 2012, and which had become final on May 28, 2012; for selective increased investment in system hardening; for creation of separate recovery mechanisms for the costs of those changes and investments; and penalties or bonuses on returns earned by the utilities based on their reliability performance. The panel's report has been referred to the MDPSC for action.

New Jersey Regulatory Matters

JCP&L currently provides BGS for retail customers who do not choose a third party EGS and for customers of third party EGSs that fail to provide the contracted service. The supply for BGS, which is comprised of two components, is provided through contracts procured through separate, annually held descending clock auctions, the results of which are approved by the NJBPU. One BGS component and auction, reflecting hourly real time energy prices, is available for larger commercial and industrial customers. The other BGS component and auction, providing a fixed price service, is intended for smaller commercial and residential customers. All New Jersey EDCs participate in this competitive BGS procurement process and recover BGS costs directly from customers as a charge separate from base rates.

On September 7, 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 requested 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. In its written Order issued July 31, 2012, the NJBPU found that a base rate proceeding "will assure that JCP&L's rates are just and reasonable and that JCP&L is investing sufficiently to assure the provision of safe, adequate and proper utility service to its customers" and ordered JCP&L to file a base rate case using a historical 2011 test year. The rate case petition was filed on November 30, 2012. In the filing, JCP&L requested approval to increase its revenues by approximately $31.5 million and reserved the right to update the filing to include costs associated with the impact of Hurricane Sandy. The NJBPU has transmitted the case to the New Jersey Office of Administrative Law for further proceedings and an ALJ has been assigned. Evidentiary hearings in the matter are currently anticipated to commence in September, 2013. On February 22, 2013, JCP&L updated its filing to request recovery of $603 million of distribution-related Hurricane Sandy restoration costs, resulting in increasing the total revenues requested to approximately $112 million.

Pursuant to a formal Notice issued by the NJBPU on September 14, 2011, public hearings were held in September 2011 to solicit comments regarding the state of preparedness and responsiveness of New Jersey's EDCs prior to, during, and after Hurricane Irene, with additional hearings held in October 2011. Additionally, the NJBPU accepted written comments through October 28, 2011 related to this inquiry. 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 selected a consultant to further review and evaluate the New Jersey EDCs' preparation and restoration efforts with respect to Hurricane Irene and the October 2011 snowstorm, and the consultant's report was submitted to and subsequently accepted by the NJBPU on September 12, 2012. JCP&L submitted written comments on the report. On January 24, 2013, based upon recommendations in its consultant's report, the NJBPU ordered the New Jersey EDCs to take a number of specific actions to improve their preparedness and responses to major storms. The order includes specific deadlines for implementation of measures with respect to preparedness efforts, communications, restoration and response, post event and underlying infrastructure issues. JCP&L is developing an appropriate plan to implement the required measures.

Ohio Regulatory Matters

The Ohio Companies primarily operate under an ESP, which expires on May 31, 2014. The material terms of the ESP include:

- Generation supplied through a CBP;
- A load cap of no less than 80%, so that no single supplier is awarded more than 80% of the tranches, 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, 2016 or when the amount of costs avoided by customers for certain types of products totals $360 million. The Ohio Companies have also agreed, subject to the outcome of certain PJM proceedings, 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.

On April 13, 2012, the Ohio Companies filed an application with the PUCO to essentially extend the terms of their current ESP for two years. The ESP 3 Application was approved by the PUCO on July 18, 2012. Several parties timely filed applications for rehearing, which the PUCO granted on September 12, 2012, solely for the purpose of giving the PUCO additional time to consider the issues raised in the applications for rehearing. The PUCO issued an Entry on Rehearing on January 30, 2013 denying all applications for rehearing.

As approved, the ESP 3 plan continues certain provisions from the current ESP including:
- Continuing the current base distribution rate freeze through May 31, 2016;

- Continuing to provide economic development and assistance to low-income customers for the two-year extension period at levels established in the existing ESP;
- Providing Percentage of Income Payment Plan customers with a 6% generation rate discount;
- Continuing to provide power to shopping and to non-shopping customers as part of the market-based price set through an auction process; and
- Continuing Rider DCR that allows continued investment in the distribution system for the benefit of customers.

As approved, the ESP 3 plan will provide additional provisions, including:

- Securing generation supply for a longer period of time by conducting an auction for a three-year period rather than a one-year period, in each of October 2012 and January 2013, to mitigate any potential price spikes for the Ohio Companies' utility customers who do not switch to a competitive generation supplier; and
- Extending the recovery period for costs associated with purchasing RECs mandated by SB221 through the end of the new ESP 3 period. This is expected to initially reduce the monthly renewable energy charge for all non-shopping utility customers of the Ohio Companies by spreading out the costs over the entire ESP period.

Under the provisions of SB221, the Ohio Companies are required to implement energy efficiency programs that will achieve a total annual energy savings equivalent of approximately 1,211 GWHs in 2012 (an increase of 416,000 MWHs over 2011 levels), 1,726 GWHs in 2013, 2,306 GWHs in 2014 and 2,903 GWHs for each year thereafter through 2025. The Ohio Companies 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 their three-year portfolio plan, as required by SB221, seeking approval for the programs they intended to implement to meet the energy efficiency and peak demand reduction requirements for the 2010-2012 period. In March 2011, the PUCO issued an Opinion and Order generally approving the Ohio Companies' 2010-2012 portfolio plan which provides for recovery of all costs associated with the programs, including lost revenues. The Ohio Companies have implemented those programs included in the plan. 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.

The Ohio Companies had filed an application for rehearing regarding portions of the PUCO's decision related to the Ohio Companies' three-year portfolio plan, which was later denied by the PUCO and the subsequent appeal was dismissed by the Supreme Court of Ohio. In accordance with PUCO Rules and a PUCO directive, the Ohio Companies filed their next three-year portfolio plan for the period January 1, 2013 through December 31, 2015 on July 31, 2012. Estimated costs for the three Ohio Companies' plans total approximately $250 million over the three-year period. Hearings were held with the PUCO in October 2012. Because the next three year-plans would not be approved until after 2012, the Ohio Companies filed a motion with the PUCO to extend their existing energy efficiency programs and related cost recovery until the new plans are approved. This motion was approved on December 12, 2012.

Additionally, under SB221, electric utilities and electric service companies in Ohio were 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 and in August 2010, 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 August 2011, the Ohio Companies conducted two RFP processes to obtain RECs to meet the statutory benchmarks for 2011 and beyond. On September 20, 2011 the PUCO opened a new docket to review the Ohio Companies' alternative energy recovery rider. The PUCO selected auditors to perform a financial and management audit, and final audit reports were filed with the PUCO on August 15, 2012. While generally supportive of the Ohio Companies' approach to procurement of RECs, the management/performance auditor recommended the PUCO examine, for possible disallowance, certain costs associated with the procurement of In-State All Renewable obligations that the auditor characterized as excessive. A hearing for this matter commenced on February 19, 2013. In March 2012, the Ohio Companies conducted an RFP process to obtain SRECs to help meet the statutory benchmarks for 2012 and beyond. With the successful completion of this RFP, the Ohio Companies achieved their in-state solar compliance requirements for 2012. The Ohio Companies also held a short-term RFP process to obtain all state SRECs and both in-state and all state non-solar RECs to help meet the statutory benchmarks for 2012. With the successful completion of this RFP, the Ohio Companies also achieved their in-state and all-state solar compliance requirements for 2012. The Ohio Companies intend to conduct an RFP in 2013 to cover their all-state SREC and their in-state and all-state REC compliance obligations.

The PUCO instituted a statewide investigation on December 12, 2012 to evaluate the vitality of the competitive retail electric service market in Ohio. The PUCO provided interested stakeholders the opportunity to provide comments on twenty-two questions by March 1, 2013, with reply comments due on March 29, 2013. The questions posed are categorized as market design and corporate separation. The Ohio Companies plan to provide their comments by the deadline, but cannot predict the outcome of this investigation.

Pennsylvania Regulatory Matters

The Pennsylvania Companies currently operate under DSPs that expire May 31, 2013, and provide for the competitive procurement of generation supply for customers that do not choose an alternative EGS or for customers of alternative EGSs that fail to provide the contracted service. The default service supply is currently provided by wholesale suppliers through a mix of long-term and short-term contracts procured through descending clock auctions, competitive requests for proposals and spot market purchases. On November 17, 2011, the Pennsylvania Companies filed a Joint Petition for Approval of their DSPs that will provide the method by which they will procure the supply for their default service obligations for the period of June 1, 2013 through May 31, 2015. The ALJ issued a Recommended Decision on June 15, 2012, that supported adoption of the Pennsylvania Companies' proposed wholesale procurement plans, denial of their proposed Market Adjustment Charge, and various modifications to the proposed competitive enhancements. The PPUC entered an opinion and order on August 16, 2012, which primarily resolved those issues related to procurement and rate design, but required the submission of revised proposals regarding the retail market enhancement programs. The Pennsylvania Companies filed revised proposals on the retail market enhancements on November 14, 2012. A final order was entered on February 15, 2013, which addressed minor changes to the Pennsylvania Companies' revised enhancement proposals and ordered two choices for cost recovery of those programs.

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, and directed ME and PN to submit a new tariff or tariff supplement reflecting the removal of marginal transmission losses from the TSC. Pursuant to a plan approved by the PPUC, ME and PN 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 losses are refunded. In April 2010, ME and PN 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 ME's and PN's TSC riders. ME and PN filed a Petition for Allowance of Appeal with the Pennsylvania Supreme Court, which was denied on February 28, 2012. On June 27, 2012, ME and PN filed a Petition for Writ of Certiorari with the Supreme Court of the United States. The certiorari petition sought review of the Pennsylvania State Court decisions. On October 9, 2012, the Supreme Court denied that petition. On July 13, 2011, ME and PN also filed a complaint in the U.S. District Court for the Eastern District of Pennsylvania for the purpose of obtaining an order that would enjoin enforcement of the PPUC and Pennsylvania court orders under a theory of federal preemption on the question of retail rate recovery of the marginal transmission loss charges. Proceedings in the U.S. District Court effectively were suspended until conclusion of the proceedings before the United States Supreme Court. When that court issued its ruling on October 9, 2012, the U.S. District Court proceedings returned to active status. Pursuant to procedural orders issued by U.S. District Court Judge Gardner, on December 21, 2012, the PPUC submitted its motion to dismiss the U.S. District Court proceedings. ME and PN submitted their answers on January 9, 2013, and subsequent pleadings were submitted by the PPUC, ME and PN. Oral argument on the PPUC motion to dismiss is scheduled for May 2013.

In each of May 2008, 2009 and 2010, the PPUC approved ME's and PN'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 transmission 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 ME's customers to provide for full recovery by December 31, 2010. Although the ultimate outcome of this matter cannot be determined at this time, ME and PN believe that they should ultimately prevail through the judicial process and therefore expect to fully recover the approximately $254 million in marginal transmission losses for the period prior to January 1, 2011.

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 on utilities that fail to achieve the required reductions in consumption and peak demand. The Pennsylvania Companies submitted a final report on November 15, 2011, in which they reported on their compliance with statutory May 31, 2011, energy efficiency benchmarks. ME, PN 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 could be subject to a statutory penalty of up to $20 million and is unable to predict the outcome of this matter.

Pursuant to Act 129, the PPUC was charged with reviewing the cost effectiveness of energy efficiency and peak demand reduction programs. The PPUC found the energy efficiency programs to be cost effective and in an Order entered on August 3, 2012, the PPUC directed all of the electric utilities in Pennsylvania to submit by November 1, 2012, a Phase II EE&C Plan that would be in effect for the period June 1, 2013 through May 31, 2016. Due to Hurricane Sandy, this deadline was extended until November 15, 2012. A hearing on the level of the Pennsylvania Companies' respective Phase II energy efficiency targets as established by the PPUC was held on October 19, 2012. The PPUC denied the Pennsylvania Companies' request for adjustments to these targets on December 5, 2012. The PPUC has deferred ruling on the need to create peak demand reduction targets until it receives more information from the EE&C statewide evaluator. The Pennsylvania Companies filed their Phase II plans and supporting testimony in November 2012. On January 16, 2013, the Pennsylvania Companies reached a settlement with all but one party on all but one issue. The settlement provides for the Pennsylvania Companies to meet with interested parties to discuss ways to expand upon the EE&C programs and incorporate any such enhancements after the plans are approved, provided that these enhancements will not jeopardize the Pennsylvania Companies' compliance with their required targets or exceed the statutory spending caps. On

February 6, 2013, the Pennsylvania Companies filed revised Phase II EE&C Plans to conform the plans to the terms of the settlement. The remaining issue, raised by a natural gas company, involved the recommendation that the Pennsylvania Companies include in their plans incentives for natural gas space and water heating appliances. This issue was litigated on January 17, 2013. Initial and reply briefs were submitted on January 28, 2013 and February 6, 2013, respectively. The evidentiary record was certified on February 7, 2013, with an order on these plans expected to be issued by the PPUC no later than the end of the first quarter of 2013.

In addition, Act 129 required utilities to file a SMIP with the PPUC. 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 its previously approved smart meter deployment plan and certain smart meter dependent aspects of the EE&C Plan. 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. WP also proposed to 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 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. A joint settlement with all parties based on these terms, with one party retaining the ability to challenge the recovery of amounts spent on WP's original SMIP, was approved by the PPUC on June 30, 2011. Additionally, WP would be permitted to seek recovery of certain other costs as part of its revised SMIP or in a future base distribution rate case.

On December 31, 2012, the Pennsylvania Companies filed their Deployment Plan. A prehearing conference was held on February 19, 2013 and evidentiary hearings will commence on May 8, 2013. The Deployment Plan requests deployment over the period 2013 to 2019, with an estimated cost of completion of about $1.25 billion. Such costs are expected to be recovered through the Pennsylvania Companies' PPUC-approved Riders SMT-C.

In the PPUC Order approving the FirstEnergy and Allegheny merger, the PPUC announced that a separate statewide investigation into Pennsylvania's retail electricity market would 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 to investigate both intermediate and long term plans that could be adopted to further foster the competitive markets, and to explore the future of default service in Pennsylvania following the expiration of the upcoming DSPs on May 31, 2015. A Tentative Order was entered by the PPUC on November 8, 2012, seeking comments regarding the end state of default service and related issues. The Pennsylvania Companies and FES filed comments on December 10, 2012. A final order was issued on February 15, 2013 providing recommendations on the entities to provide default service, the products to be offered, billing options, customer education, and licensing fees and assessments, among other items.

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 electricity 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 was published on February 11, 2012, and comments were filed by the Pennsylvania Companies and FES on March 27, 2012. If implemented these rules could require a significant change in the ways FES and the Pennsylvania Companies do business in Pennsylvania, and could possibly have an adverse impact on their results of operations and financial condition. Pennsylvania's Independent Regulatory Review Commission subsequently issued comments on the proposed rulemaking on April 26, 2012, which called for the PPUC to further justify the need for the proposed revisions by citing a lack of evidence demonstrating a need for them. The House Consumer Affairs Committee of the Pennsylvania General Assembly also sent a letter to the Independent Regulatory Review Commission on July 12, 2012, noting its opposition to the proposed regulations as modified.

West Virginia Regulatory Matters

In April 2010, MP and PE filed with the WVPSC a Joint Stipulation and Agreement of Settlement reached with the other parties in a proceeding for an annual increase in retail rates that provided for:

- $40 million annualized base rate increases effective June 29, 2010;
- Deferral of February 2010 storm restoration expenses over a maximum five-year period;
- Additional $20 million annualized base rate increase effective in January 2011;
- Decrease of $20 million in ENEC rates effective January 2011, providing for deferral of related costs for later recovery in 2012; and
- Moratorium on filing for further increases in base rates before December 1, 2011, except under specified circumstances.

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

In February 2011, MP and PE filed a petition with the WVPSC seeking an order declaring that MP owns all RECs associated with the energy and capacity that MP is required to purchase pursuant to electric energy purchase agreements between MP and three NUG facilities in West Virginia. The City of New Martinsville and Morgantown Energy Associates, each the owner of one of the contracted resources, have participated in the case in opposition to the petition. The WVPSC issued an order on November 22, 2011, granting ownership of all RECs produced by the facilities to MP, and holding that an electric utility that purchases electric energy and capacity under an electric power purchase agreement with a Qualifying Facility under PURPA owns the RECs associated with that purchase. The RECs are being used for compliance purposes. The West Virginia Supreme Court issued an Order on June 11, 2012, upholding the WVPSC's decision. The City of New Martinsville and Morgantown Energy Associates filed petitions at FERC alleging the WVPSC order violated PURPA and requesting that FERC initiate an enforcement action. On April 24, 2012, FERC ruled that FERC jurisdictional contracts for the sale of Qualifying Facility capacity entered into under PURPA are intended to pay only for electric energy and capacity (and not for RECs), and that state law controlled on the issues of determining which entity owns RECs and how they are transferred between entities. FERC declined to act on the petitions and instead noted that the City of New Martinsville and Morgantown Energy Associates could file complaints in the U.S. District Court. FERC also noted there may be language in the WVPSC order that is inconsistent with PURPA. MP and PE filed for rehearing of FERC's order taking the position that the WVPSC order is consistent with PURPA, which was denied by FERC on September 20, 2012. The City of New Martinsville filed a complaint in the U.S. District Court for the Southern District of West Virginia on June 1, 2012, alleging that the WVPSC order violates PURPA. Morgantown Energy Associates has joined in filing a similar complaint and requesting damages in the same U.S. District Court. MP and PE filed for judgment on the pleadings in both cases on January 25, 2013.

The WVPSC has proceedings for each West Virginia electric utility to establish reliability targets for distribution performance. The parties entered into a settlement in September 2012 resolving all issues and revising performance targets beginning in 2014. The settlement has been approved by the WVPSC.

The WVPSC opened a general investigation into the June 29, 2012, derecho windstorm with data requests for all utilities. A public meeting for presentations on utility responses and restoration efforts was held on October 22, 2012 and two public input hearings have been held. The WVPSC issued an Order in this matter on January 23, 2013 closing the proceeding and directing electric utilities to file a vegetation management plan within six months and to propose a cost recovery mechanism. This Order also requires MP and PE to file a status report regarding improvements to their storm response procedures by the same date.

The West Virginia ENEC fuel case was filed by MP and PE at the WVPSC in August 2012 with a projected over-recovery of approximately $66 million under then current rates for the next year, January 1, 2013 through December 31, 2013. MP and PE proposed no change in overall rates on January 1, 2013; however, MP and PE proposed establishing a separate regulatory liability for the difference between the recommended 2013 ENEC rates and the current ENEC rates. This estimated $66 million liability was proposed to offset the rate relief MP and PE seek to become effective with the completion of a proposed generation resource acquisition transaction described below. A hearing was held in December 2012 in the ENEC fuel case and the WVPSC denied MP and PE's request to delay the $66 million rate decrease and ordered that the fuel rate decrease be implemented on January 1, 2013.

MP and PE filed their Resource Plan with the WVPSC in August 2012 detailing both supply and demand forecasts and noting a substantial capacity deficiency. MP and PE have filed a Petition for approval of a Generation Resource Transaction with the WVPSC in November 2012 that proposes a net ownership transfer of 1,476 MW of coal-fired generation capacity to MP by May 2013. The proposed transfer would involve MP's acquisition of the remaining ownership of the Harrison Power Station from AE Supply and the sale of MP's minority interest in the Pleasants Power Station to AE Supply. The proposed transfer would implement a cost-effective plan to assist MP in meeting its energy and capacity obligations with its own generation resources, eliminating the need to make unhedged electricity and capacity purchases from the spot market, which is expected to result in greater rate stability for MP's customers. The plan is expected to remedy MP's capacity and energy shortfalls, which are projected to worsen due to a projected increase in annual load growth of approximately 1.4%. MP and PE also filed with FERC for authorization to effect these transfers. MP and PE will file a base rate case no later than six months from the completion of the transaction. On February 11, 2013, the WVPSC issued an order adopting a procedural schedule for this matter with hearings scheduled for May 29-31, 2013.

FERC Matters

PJM Transmission Rate

PJM and its stakeholders have been debating the proper method to allocate costs for new transmission facilities. While FirstEnergy and other parties advocated for a traditional "beneficiary pays" (or usage based) approach, others advocate for “socializing” the costs on a load-ratio share basis - each customer in the zone would pay based on its total usage of energy within PJM. This debate is framed by regulatory and court decisions. On August 6, 2009, the U.S. Court of Appeals for the Seventh Circuit found that FERC had not supported a prior FERC decision to allocate costs for new 500 kV and higher voltage facilities on a load ratio share basis and, based on that finding, remanded the rate design issue to FERC. In an order dated January 21, 2010, FERC set this matter for a “paper hearing” and requested parties to submit written comments. FERC identified nine separate issues for comment and directed PJM to file the first round of comments. PJM filed certain studies with FERC on April 13, 2010, which demonstrated that allocation of the cost of high voltage transmission facilities on a beneficiary pays basis results in certain LSEs in PJM bearing the majority of the costs. Subsequently, numerous parties, including FirstEnergy, 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 utility commissions supported the use of the beneficiary pays approach for cost allocation for high voltage transmission facilities. Other utilities and state utility commissions supported continued socialization of these costs on a load ratio share basis. On March 30, 2012, FERC issued an order on remand reaffirming its prior decision 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 (or socialization) rate based on the amount of load served in a transmission zone and concluding that such methodology is just and reasonable and not unduly discriminatory or preferential. On April 30, 2012, FirstEnergy requested rehearing of FERC's March 30, 2012 order. FirstEnergy's request for rehearing remains pending before FERC.

Order No. 1000, issued by FERC on July 21, 2011, required the submission of a compliance filing by PJM or the PJM transmission owners demonstrating that the cost allocation methodology for new transmission projects directed by the PJM Board of Managers satisfied the principles set forth in the order. To demonstrate compliance with the regional cost allocation principles of the order, the PJM transmission owners, including FirstEnergy, submitted a filing to FERC on October 11, 2012, proposing a hybrid method of 50% beneficiary pays and 50% postage stamp to be effective for RTEP projects approved by the PJM Board of Managers on and after the effective date of the compliance filing. On January 31, 2013, FERC conditionally accepted the hybrid method to be effective on February 1, 2013, subject to refund and to a future order on PJM's separate Order No. 1000 compliance filing. FERC stated that it will address the merits of the PJM transmission owners' October 11, 2012 filing, including comments, protests and answers submitted in regard thereto, in its future order on PJM's compliance filing. Filings to demonstrate compliance with the interregional cost allocation principles of the order are due to FERC by April 2013.

RTO Realignment

On June 1, 2011, ATSI and the ATSI zone transferred from MISO to 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. While most of the matters involved with the move have been resolved, the question of ATSI's responsibility for certain costs for the “Michigan Thumb” transmission project continues to be disputed; the details of the dispute are discussed below under "MISO Multi-Value Project Rule Proposal." In addition, FERC denied recovery of certain charges that collectively can be described as "exit fees" by means of ATSI's transmission rate totaling approximately $78.8 million until such time as ATSI submits a cost/benefit analysis that demonstrates net benefits to customers from the move. ATSI has asked for rehearing of FERC's orders that address the Michigan Thumb transmission project and the exit fee issue. On December 21, 2012, ATSI and other parties filed a proposed settlement agreement with FERC that, if accepted by FERC, should resolve certain of the exit fee issues. Thereafter, the OCC protested the December 21, 2012 settlement filing, which remains pending before FERC. In a prior order, FERC ruled that the costs for certain "legacy RTEP" transmission projects in PJM could be charged to transmission customers in the ATSI zone. ATSI sought rehearing of the question of whether the ATSI zone should pay these legacy RTEP charges and, on September 20, 2012, FERC denied ATSI's request for rehearing. On November 19, 2012, ATSI filed a petition for review with the D.C. Circuit Court of Appeals of FERC's ruling on the "legacy RTEP" issue.

The 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 (not including ATSI or FirstEnergy) jointly filed with FERC a proposed cost allocation methodology for certain new transmission projects. The new transmission projects - described as MVPs - are a class of transmission projects that are approved via MISO's MTEP process. Under MISO's proposal, the costs of “Michigan Thumb” MVP project that was 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 and charged to ATSI. MISO estimated that approximately $16 million in annual revenue requirements associated with the Michigan Thumb Project would be allocated to the ATSI zone upon completion of project construction.

FirstEnergy has filed pleadings in opposition to the MISO's efforts to “socialize” the costs of the Michigan Thumb Project onto ATSI or onto ATSI's customers. FirstEnergy asserts legal, factual and policy arguments. To date, FERC has responded in a series of orders that may require ATSI to absorb the charges for the Michigan Thumb Project pending the outcome of further regulatory proceedings and appeals. These further proceedings can be divided into two classes: litigation related to MISO's generic MVP cost allocation proposal; and litigation related to MISO's "Schedule 39" tariff that purports to charge the MVP costs to ATSI.

On October 31, 2011, FirstEnergy filed a Petition of Review of certain of FERC's orders that address the generic MVP tariffs 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. Briefs were due from the parties through 2012 and early 2013, and oral arguments will be scheduled in 2013.

In February 2012, FERC accepted the MISO's proposed Schedule 39 tariff, subject to hearings and potential refund of MVP charges to ATSI. MISO's Schedule 39 tariff is the vehicle through which the MISO plans to charge the Michigan Thumb Project costs to ATSI. FERC set for hearing the question of whether it is just and reasonable for ATSI to pay the Michigan Thumb Project costs and, if so, the amount of and methodology for calculating ATSI's Michigan Thumb Project cost responsibility. The hearings are expected to start in April 2013.

FirstEnergy cannot predict the outcome of these proceedings 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 several 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 had previously remanded one of those proceedings to FERC, which dismissed the claims of the California Parties in May 2011, and affirmed the dismissal in June 2012. On June 20, 2012, the California Parties appealed FERC's decision back to the Ninth Circuit. The timing of further action by the Ninth Circuit is unknown.

In another proceeding, in June 2009, the California Attorney General on behalf of certain California parties, filed another complaint with FERC against various sellers, including AE Supply, again seeking refunds for transactions in the California energy markets during 2000 and 2001. The above-noted transactions with CDWR are the basis for including AE Supply in this complaint. AE Supply filed a motion to dismiss, which was granted by FERC in May 2011, and affirmed by FERC in June 2012. The California Attorney General has appealed FERC's dismissal of its complaint to the Ninth Circuit, which has consolidated the case with other pending appeals related to California refund claims, and stayed the proceedings pending further order.

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 was proposed to be comprised of a 765 kV transmission line 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. On August 24, 2012, the PJM Board of Managers canceled the PATH project, which it had originally suspended in February 2011. All applications for authorization to construct the project filed with state commissions have been withdrawn. As a result, approximately $62 million and approximately $59 million in costs incurred by PATH-Allegheny and PATH-WV, respectively, were reclassified from net property, plant and equipment to a regulatory asset for future recovery. On September 28, 2012, those companies requested authorization from FERC to recover the costs with a proposed return on equity of 10.9% (10.4% base plus 0.5% RTO membership) from PJM customers over the next five years. Several parties protested the request. On November 30, 2012, FERC issued an order denying the 0.5% return on equity adder for RTO membership and allowing the tariff changes enabling recovery of these costs to become effective on December 1, 2012 subject to settlement judge procedures and hearing if the parties do not agree to a settlement. The issues subject to settlement include the prudence of the costs, the base return on equity and the period of recovery. Depending on the outcome of a possible settlement or hearing, if settlement is not achieved, PATH-Allegheny and PATH-WV may be required to refund certain amounts that have been collected under their formula rate.

PATH-Allegheny and PATH-WV have requested rehearing of FERC's denial of the 0.5% return on equity adder for RTO membership; that request for rehearing remains pending before FERC. In addition, FERC has consolidated for settlement judge procedures and hearing purposes two formal challenges to the PATH formula rate annual updates submitted to FERC in June 2010 and June 2011. FirstEnergy cannot predict the outcome of these matters or estimate the possible loss or range of loss.

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 owns the remaining interest in the plant. The project was constructed in the early 1960s, and became operational in 1965. FERC issued a license for authorization to operate the project. 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 the NEPA), and provide opportunities for intervention and protests by affected third parties. FERC may hold hearings during the five-year ILP licensure process. FirstEnergy expects FERC to issue the new license in the first quarter of 2013. To the extent 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.

On June 29, 2012, FERC Staff sent an 'Additional Information Request' to JCP&L. In the request, FERC Staff voiced concern about JCP&L's proposed 'fusegate' overflow structure, and asked for additional information and analysis that would support a FERC decision to authorize installation of this structure. JCP&L and FERC Staff subsequently agreed that JCP&L would install the proposed fusegate overflow structure. In spring 2012, the New Jersey State Historic Preservation Office asked that JCP&L agree to additional measures to protect certain prehistoric sites that are located on the Yards Creek property. JCP&L was able to negotiate an agreement for such protections, which was executed as of February 5, 2013. At this time, we expect that JCP&L's license application will be uncontested and that FERC will renew the license in the first quarter of 2013.

Seneca

The Seneca Pumped Storage Project is a 451 MW hydroelectric project located in Warren County, Pennsylvania owned and operated by FG. FG 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, FG initiated the ILP relicensing process by filing its notice of intent to relicense and related documents in the license docket.

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. On November 30, 2010, the Seneca Nation filed its notice of intent to relicense and related documents necessary for the Seneca Nation to submit a competing application. FG believes it is entitled to a statutory “incumbent preference” under Section 15 and that it ultimately should prevail in these proceedings. Nevertheless, the Seneca Nation's pleadings reflect the Nation's apparent intent to obtain the license for the facility, and to assume ownership and operation of the facility as contemplated by the statute.

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 January 7, 2013, FirstEnergy and the Seneca Nation submitted their respective reports for the 2012 study season. On January 31 and February 1, 2013, respectively, the Seneca Nation and FirstEnergy each submitted their respective proposed study plans for the 2013 study season. The study processes will extend through approximately November 2013.

MISO Capacity Portability

On June 11, 2012, FERC issued a Notice of Request for Comments regarding whether existing rules on transfer capability act as barriers to the delivery of capacity between MISO and PJM. FERC is responding to suggestions from MISO and the MISO stakeholders that PJM's rules regarding the criteria and qualifications for external generation capacity resources be changed to ease participation by resources that are located in MISO in PJM's RPM capacity auctions. FirstEnergy submitted comments on August 10, 2012, and reply comments on August 27, 2012. In the fall of 2012, FirstEnergy participated in certain stakeholder meetings to review various proposals advanced by MISO. Although none of MISO's proposals attracted significant stakeholder support, on January 3, 2013, MISO filed a pleading with FERC that renewed many of the arguments advanced in prior MISO filings and asked FERC to take expedited action to address MISO's allegations. On January 18, 2013, FirstEnergy and other parties submitted filings explaining that MISO's concerns largely are without foundation and suggesting that FERC order that the remaining concerns be addressed in the existing stakeholder process that is described in the PJM/MISO Joint Operating Agreement. Changes to the criteria and qualifications for participation in the PJM RPM capacity auctions could have a significant impact on the outcome of those auctions, including a negative impact on the prices at which those auctions would clear.

MOPR Reform

On December 7, 2012, PJM filed amendments to its tariff to revise the MOPR used in the RPM. PJM revised the MOPR to add two broad, categorical exemptions, eliminate an existing exemption, and to limit the applicability of the MOPR to certain capacity resources. The filing also included related and conforming changes to the RPM posting requirements and to those provisions describing the role of the Independent Market Monitor for the PJM Region. PJM proposed an effective date for these Tariff changes of February 5, 2013. FirstEnergy submitted comments on December 28, 2012, and reply comments on January 25, 2013. FERC has not issued an order on the proposed reforms. On February 5, 2013, FERC Staff issued a deficiency letter to PJM requesting additional information on certain components of the proposed MOPR reforms, including the exemptions and resources qualifying for the MOPR. PJM has 30 days to respond to FERC Staff's requests. Changes to the MOPR could have a significant impact on the outcome of the RPM auctions, including a negative impact on the prices at which those auctions would clear.

Synchronous Condensers

On December 20, 2012, FERC approved the transfer by FG to ATSI of certain deactivated generation assets associated with Eastlake Units 1 through 5 and Lakeshore Unit 18 to facilitate their conversion to synchronous condensers to provide voltage support on the ATSI transmission system. The transfer price of the assets is approximately $21.5 million and the estimated conversion cost is approximately $60 million. The transfer of Eastlake Units 4 and 5 was completed on January 31, 2013 and ATSI's completion of the conversion of those units to synchronous condensers is expected to be completed by June 1, 2013 for Eastlake Unit 5 and by December 1, 2013 for Eastlake Unit 4. The transfer of the remaining units and their conversion to synchronous condensers will occur when the use of the units for RMR purposes is no longer required. On January 22, 2013, ATSI requested clarification or, in the alternative, rehearing with respect to a statement in the FERC order authorizing the transfer that ATSI's current formula rate does not include the accounts and components necessary to allow for recovery of the costs associated with acquisition of the transferred assets and that ATSI must make a filing under Section 205 of the FPA in order to recover those costs. ATSI believes its formula rate currently includes the necessary accounts and components to allow for such recovery and that a Section 205 filing is not required. That request for rehearing remains pending before FERC.

FTR Underfunding Complaint

In PJM, FTRs are a mechanism to hedge congestion and operate as a financial replacement for physical firm transmission service. FTRs are financially-settled instruments that entitle the holder to a stream of revenues based on the hourly congestion price differences across a specific transmission path in the PJM Day-ahead Energy Market. However, due to certain language in the PJM tariff, the funds that are set aside to pay FTRs can be diverted to other uses, resulting in “underfunding” of FTR payments. Since June of 2010, FES and AE Supply have lost more than $55 million in revenues that they are entitled to receive as FTR holders to hedge congestion costs. FES and AE Supply continue to experience significant underfunding.

On December 28, 2011, FES and AE Supply filed a complaint with FERC for the purpose of modifying certain provisions in the PJM tariff to eliminate FTR underfunding. On March 2, 2012, FERC issued an order dismissing the complaint. In its order, FERC ruled that it was not appropriate to initiate action at that time because of the unknown root causes of FTR underfunding.FERC directed PJM to convene stakeholder proceedings for the purpose of determining the root causes of the FTR underfunding. FERC went on to note that its dismissal of the complaint was without prejudice to FES and AE Supply or any other affected entity filing a complaint if the stakeholder proceedings proved unavailing. FES and AE Supply sought rehearing of FERC's order and, on July 19, 2012, FERC denied rehearing. In April, 2012, PJM issued a report on FTR underfunding. However, the PJM stakeholder process proved unavailing as the stakeholders were not willing to change the tariff to eliminate FTR underfunding. Accordingly, on February 15, 2013, FES and AE Supply refiled their complaint for the purpose of changing the PJM tariff to eliminate FTR underfunding. This complaint is pending before FERC.

Capital Requirements

Our capital spending for 2013 is expected to be approximately $2.4 billion (excluding nuclear fuel). 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 $205 million in 2013. Actual capital expenditures for 2012 and anticipated expenditures for 2013, 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.

	2012 Actual [1][2]	Capital Expenditures Forecast 2013[3]
	(In millions)	
OE	$272	$150
Penn	35	26
CEI	202	111
TE	75	46
JCP&L	689	200
ME	179	105
PN	172	160
MP	283	143
PE	129	88

WP	172	124
ATSI	180	210
TrAIL	89	79
FG	128	208
NG	425	449
AE Supply	117	183
Other subsidiaries	122	98
Total	$3,269	$2,380

(1) Includes approximately $485 million related to Hurricane Sandy, of which approximately $354 million related to JCP&L.
(2) Includes approximately $223 million related to the capitalization of mark-to-market adjustments for pensions and OPEB costs.

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(3) Excludes capitalized mark-to-market adjustments for pensions and OPEB costs, which cannot be estimated.

The following table presents scheduled debt repayments for outstanding long-term debt as of December 31, 2012, excluding capital leases for the next five years. PCRBs that can be tendered for mandatory purchase prior to maturity are reflected in 2013.

	2013	2014-2017	Total
	(In millions)		
FE	$—	$150	$150
FES	1,097	1,585	2,682
OE	1	404	405
JCP&L	36	701	737
Other(1)	836	2,828	3,664
Total	$1,970	$5,668	$7,638

(1) Includes debt of non-registrant subsidiaries and the elimination of certain intercompany debt.

The following tables display consolidated operating lease commitments as of December 31, 2012.

Operating Leases	FirstEnergy Lease Payments	Capital Trust(1)	Net
	(In millions)		
2013	$256	$46	$210
2014	250	48	202
2015	246	40	206
2016	214	13	201
2017	126	3	123
Years thereafter	1,678	—	1,678
Total minimum lease payments	$2,770	$150	$2,620

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

Operating Leases	FES	OE(1)	JCP&L
	(In millions)		
2013	$144	$146	$9
2014	143	145	8
2015	141	145	7
2016	130	116	8
2017	81	46	7
Years thereafter	1,581	3	52
Total minimum lease payments	$2,220	$601	$91

(1) Includes certain minimum lease payments associated with NG's lessor equity interests in Perry and Beaver Valley Unit 2 that are eliminated in consolidation (see Note 5, Leases, of the Combined Notes to Consolidated Financial Statements).

During 2012, FG acquired certain lessor equity and other interests in connection with exercising the EBO option under the 1987 Bruce Mansfield sale and leaseback transactions for an aggregate purchase price of approximately $262.2 million. Additionally, FG is continuing the appraisal process with one remaining party and is currently involved in litigation with two other parties each of which is disputing the appraisal of the fair market value of the relevant leased assets. During 2012, NG repurchased lessor equity interests in OE's existing sale and leaseback of Beaver Valley Unit 2 for $129 million.

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 2013 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 the issuance of long-term debt and/or equity. 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 $1,969 million of short-term borrowings as of December 31, 2012, and no significant short-term borrowings as of December 31, 2011. FirstEnergy’s available liquidity as of January 31, 2013, was as follows:

Borrower(s)	Type	Maturity	Commitment	Available Liquidity
			(In millions)	
FirstEnergy[1]	Revolving	May 2017	$2,000	$776
FES / AE Supply	Revolving	May 2017	2,500	2,488
FET[2]	Revolving	May 2017	1,000	—
AGC	Revolving	Dec. 2013	50	15
		Subtotal	$5,550	$3,279
		Cash	—	61
		Total	$5,550	$3,340

(1) FE and the Utilities.
(2) Includes FET, ATSI and TrAIL.

FE and certain of its subsidiaries participate in three five-year syndicated revolving credit facilities with aggregate commitments of $5.5 billion (Facilities). The Facilities consist of a $2.0 billion aggregate FirstEnergy Facility, a $2.5 billion FES/AE Supply Facility and a $1.0 billion FET Facility, that are each available until May 2017, 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 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 11, Capitalization, of the Combined Notes to Consolidated Financial Statements.

FE’s primary source of cash for continuing operations as a holding company is cash from the operations of its subsidiaries. During 2012, FirstEnergy received $900 million of cash dividends and capital returned from its subsidiaries and paid $920 million in cash dividends to common shareholders.

As of December 31, 2012, the Ohio Companies and Penn had the aggregate capacity to issue approximately $2.5 billion of additional FMBs on the basis of property additions and retired bonds under the terms of their respective FMB 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 to incur additional secured debt not otherwise permitted by a specified exception of up to $161 million. As a result of the indenture provisions, CEI and TE cannot incur any additional secured debt. ME and PN had the capability to issue secured debt of approximately $395 million and $404 million, respectively, under provisions of their senior note indentures as of December 31, 2012. In addition, based upon their net earnings and available bondable property additions as of December 31, 2012, MP, PE and WP had the capacity to issue approximately $1.5 billion of additional FMBs in the aggregate under the terms of their FMB indentures. The issuance of FMBs by these companies is subject to compliance with the financial covenants of the Facilities and any required regulatory approvals and may be subject to statutory and/or charter limitations.

Based upon FG’s and NG's net earnings and available bondable property additions under their FMB indentures as of December 31, 2012, FG and NG had the capacity to issue $2.0 billion and $2.4 billion, respectively, of additional FMBs under the terms of their indentures. 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. An NRC ASLB granted a hearing on the Davis-Besse license renewal application to a group of petitioners. The NRC subsequently narrowed the scope of admitted contentions in this proceeding to a challenge to the computer code used to model source terms in FENOC's SAMA analysis. On December 28, 2012, the ASLB issued two decisions that granted FENOC's motion for summary dismissal of the remaining SAMA contention and denied the Intervenors' request for a new contention on the Davis-Besse Shield Building. The ASLB declined to terminate the adjudication. In an earlier order dated August 7, 2012, the NRC stated that it will not issue final licensing decisions until it has appropriately addressed the challenges to the NRC Waste Confidence Decision and Temporary Storage Rule and all pending contentions on this topic should be held in abeyance until further order. In a September 6, 2012, staff requirements memorandum, the NRC directed the staff to publish a final rule and EIS to support an updated Waste Confidence Decision and temporary storage rule within 24 months. The ASLB has suspended further consideration of the Intervenors' proposed contention on the environmental impacts of spent fuel storage in the Davis-Besse license renewal proceeding.

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, 2012, FirstEnergy had approximately $2.2 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 guaranty, 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. FirstEnergy currently maintains a $95 million parental guaranty in support of the decommissioning of nuclear facilities which is expected to increase to approximately $135 million in 2013. In December 2012, FirstEnergy Corp. entered into an additional $11 million parental guaranty in support of the decommissioning of the spent fuel storage facilities located at its Davis-Besse and Perry nuclear facilities.

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. 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. 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 sub-surface hairline cracks in the upper portion of the shield building and in the vicinity of the main steam line penetrations. A team of industry-recognized structural concrete experts and Davis-Besse engineers 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. On December 6, 2011, the Davis-Besse plant returned to service. By a letter dated November 7, 2012, the NRC concluded that FENOC satisfied all of the commitments contained in the CAL related to Davis-Besse Shield Building. FENOC continues to monitor the status of the Shield Building.

By a 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 conducted several supplemental inspections, including an inspection using Inspection Procedure 95002 to determine if the root cause and contributing causes of risk significant performance issues were understood, the extent of condition was identified, whether safety culture contributed to the performance issues, and if FENOC's corrective actions are sufficient to address the causes and prevent recurrence. On December 28, 2012, the NRC issued a report on the 95002 Inspection that concluded that FENOC "did not provide assurance that the corrective actions for performance issues associated with the Occupational Exposure Control Effectiveness PI were sufficient to address the root and contributing causes and prevent recurrence." Moreover, the NRC also concluded that FENOC "did not adequately address corrective actions for the White NOV." As a result, the NRC will hold open both a parallel PI inspection finding on the occupational exposure issues and the White finding. The NRC will conduct a future inspection to verify the effectiveness of FENOC's corrective actions. Additional adverse findings by the NRC could result in additional NRC oversight and further inspection activities.

By a letter dated January 17, 2013, the NRC notified FENOC that the Perry plant would remain in Column 3 of the action matrix for the NRC reactor oversight process. It stated that although “Perry meets the definition in Inspection Manual Chapter 0305 for Multiple/Repetitive Degraded Cornerstone, Column 4, of the Action Matrix,” current performance issues are well understood and appear to be limited to occupational radiation safety, at present and thus the regulatory actions specified for Column 3 of the Action Matrix are more appropriate. The NRC also noted that Perry would move to Column 4 if: (1) the follow-up 95002 inspection, scheduled for completion in the May-July 2013 timeframe, identifies a significant weakness in Perry's performance; (2) Perry is unable to complete corrective actions necessary to permit the follow-up 95002 inspection to be completed before the end of July 2013; or (3) if another Greater-than-Green PI or finding is identified (other than a change of color for the current Occupational Exposure Control Effectiveness PI issue). Additional adverse findings by the NRC could result in further inspection activities and/or other regulatory actions.

On March 12, 2012, the NRC issued orders requiring safety enhancements at U.S. reactors based on recommendations from the lessons learned Task Force review of the accident at Japan's Fukushima Daiichi nuclear power plant. These orders require additional mitigation strategies for beyond-design-basis external events, and enhanced equipment for monitoring water levels in spent fuel pools. The NRC also requested that licensees including FENOC: re-analyze earthquake and flooding risks using the latest information available; conduct earthquake and flooding hazard walkdowns at their nuclear plants; assess the ability of current communications systems and equipment to perform under a prolonged loss of onsite and offsite electrical power; and assess plant staffing levels needed to fill emergency positions. These and other NRC requirements adopted as a result of the accident at Fukushima Daiichi are likely to result in additional material costs from plant modifications and upgrades at FENOC's nuclear facilities.

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 higher burn up 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 and that the NRC might consider imposing restrictions on reactor operating limits. On March 16, 2012, FENOC submitted its response to the NRC demonstrating that the NRC requirements are being met. After a detailed review of FENOC's submittal and in a January 25, 2013 evaluation, the NRC confirmed the FENOC's evaluation model remains adequate and determined that the schedule for re-analysis was acceptable. The plant remains compliant with regulations regarding fuel parameters. FENOC also agreed to submit to the NRC revised large break loss of coolant accident analyses by December 15, 2016, that further consider the effects of fuel pellet thermal conductivity degradation.

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, NG-$408 million, and TE-$22 million) per incident but not more than $70 million (OE-$6 million, NG-$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 billion (OE-$168 million, NG-$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 $14 million (OE-$1 million and NG-$13 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 $2.75 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 $69 million (OE-$6 million, NG-$61 million and TE-$2 million).

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 $1.06 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.

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, utilizing combustion controls and post-combustion controls, generating more electricity from lower or non-emitting plants and/or using emission allowances.

In July 2008, three complaints representing multiple plaintiffs were filed against FG 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 complaint was filed on behalf of twenty-one individuals and the other is a class action complaint seeking certification as a class with the eight named plaintiffs as the class representatives. FG believes the claims are without merit and intends to vigorously 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 possible loss or range of loss.

In December 2007, the states of New Jersey and Connecticut filed CAA citizen suits in the U.S. District Court for the Eastern District of Pennsylvania 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 ME in 1999) and ME. Specifically, these suits allege that “modifications” at Portland Units 1 and 2 occurred between 1980 and 2005 without pre-construction 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. The Court dismissed New Jersey's and Connecticut's claims for injunctive relief against ME, but denied ME's motion to dismiss the claims for civil penalties. In February 2012, GenOn announced its plans to deactivate the Portland Station in January 2015 citing EPA emissions limits and compliance schedules to reduce SO_2 air emissions by approximately 81% at the Portland Station by January 6, 2015. On July 27, 2012, FirstEnergy filed a motion for summary judgment arguing the Plaintiff's remaining claims for civil penalties are barred by the statute of limitations. On November 1, 2012, the other defendants and the plaintiffs filed motions for summary judgment regarding various claims. On February 22, 2013, the Court heard oral argument on the motions for summary judgment and a jury trial regarding liability was set for April 23, 2013. The parties dispute the scope of ME's indemnity obligation to and from Sithe Energy. FirstEnergy believes the claims are without merit and intends to vigorously 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 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. ME, JCP&L and PN, as former owners of the facilities, are unable to predict the outcome of this matter or estimate the possible loss or range of loss.

In January 2011, the U.S. DOJ filed a complaint against PN in the U.S. District Court for the Western District of Pennsylvania seeking injunctive relief against PN based on alleged “modifications” at the coal-fired Homer City generating plant during 1991 to 1994 without pre-construction 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 filed separate complaints regarding Homer City seeking injunctive relief and civil penalties. In October 2011, the Court dismissed all of the claims with prejudice of the U.S. DOJ and the Commonwealth of Pennsylvania and the states of New Jersey and New York against all of the defendants, including PN. 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 which has scheduled oral argument on May 17, 2013. PN believes the claims are without merit and intends to vigorously defend itself against the allegations made in these complaints. The parties dispute the scope of NYSEG's and PN's indemnity obligation to and from Edison International. PN is unable to predict the outcome of this matter or estimate the loss or possible range of loss.

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. 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. FG intends to comply with the CAA and Ohio regulations; 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. In September 2007, AE 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. On June 29, 2012 and January 31, 2013, EPA issued additional CAA section 114 requests for the Harrison coal-fired plant seeking information and documentation relevant to its operation and maintenance, including capital projects undertaken since 2007. AE intends to comply with the CAA but, at this time, is unable to predict the outcome of this matter or estimate the possible loss or range of loss.

In June 2005, the PA DEP and the Attorneys General of New York, New Jersey, Connecticut and Maryland filed suit against AE, AE Supply and the Allegheny Utilities in the U.S. District Court for the Western District of Pennsylvania alleging, among other things, that Allegheny performed major modifications in violation of the PSD provisions of the CAA and the Pennsylvania Air Pollution Control Act at the coal-fired Hatfield's Ferry, Armstrong and Mitchell Plants in Pennsylvania. A non-jury trial on liability only was held in September 2010. The parties are awaiting a decision from the District Court, but there is no deadline for that decision. FirstEnergy is unable to predict the outcome or estimate the possible loss or range of loss.

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 decided that CAIR violated the CAA but 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 decision. In July 2011, the EPA finalized 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 December 30, 2011, CSAPR was stayed by the U.S. Court of Appeals for the District of Columbia Circuit and was ultimately vacated by the Court on August 21, 2012. On January 24, 2013, EPA and intervenors' petitions seeking rehearing or rehearing en banc were denied by the U.S. Court of Appeals for the District of Columbia Circuit. The Court has ordered EPA to continue administration of CAIR until it finalizes a valid replacement for CAIR. Depending on the outcome of these proceedings and how any final rules are ultimately implemented, FG's and AE Supply's future cost of compliance may be substantial and changes to FirstEnergy's operations may result.

Hazardous Air Pollutant Emissions

On December 21, 2011, the EPA finalized the MATS imposing emission limits for mercury, PM, and HCL for all existing and new coal-fired electric generating units effective in April 2015 with 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. On December 28, 2012, the WVDEP granted a conditional exemption through April 16, 2016 for MATS compliance at the Fort Martin, Harrison and Pleasants Power stations. 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. MATS has been challenged in the U.S. Court of Appeals for the District of Columbia Circuit by various entities, including FirstEnergy's challenge of the PM emission limit imposed on petroleum coke boilers, such as Bay Shore Unit 1. FirstEnergy and other entities have also petitioned EPA to reconsider and revise various regulatory requirements under MATS. Depending on the outcome of these proceedings and how the MATS are ultimately implemented, FirstEnergy's future cost of compliance with MATS is estimated to be approximately $975 million.

As of September 1, 2012, Albright, Armstrong, Bay Shore Units 2-4, Eastlake Units 4-5, R. Paul Smith, Rivesville and Willow Island have been deactivated. On April 25, 2012, PJM concluded its initial analysis of the reliability impacts from the previously announced plant deactivations and requested RMR arrangements for Eastlake Units 1-3, Ashtabula Unit 5 and Lake Shore Unit 18 through the spring of 2015. During the year ended December 31, 2012, FirstEnergy recognized pre-tax severance expense of approximately $14 million ($10 million by FES) as a result of deactivations. These costs are included in "other operating expenses" in the Consolidated Statements of Income.

FirstEnergy has various long-term coal transportation agreements, some of which run through 2025 and certain of which are related to the plants described above. Penalties for delivery shortfalls for 2012 under those agreements are approximately $60 million unless, as we believe, those delivery shortfalls are excused by the force majeure provisions of those agreements. However, if we fail to reach a resolution with the counterparties and were it ultimately determined that the force majeure provisions do not excuse those delivery shortfalls, our results of operations and financial condition could be materially adversely impacted.

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 NSR pre-construction permits would be required including an emissions applicability threshold of 75,000 tons per year of CO_2 equivalents 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, South 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.

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 U.S. 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 to reduce fish impingement to a 12% annual average and determine site-specific controls, if any, to reduce entrainment of aquatic life following studies to be provided to permitting authorities. In July 2012, the period for finalizing the Section 316(b) regulation was extended to July 27, 2013. 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 FG 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 January 10, 2013, EPA posted for a 30-day public comment period executed Consent Agreements and unexecuted Final Orders requiring payment of a $125,000 civil penalty and the transfer of 195 acres of wetlands to a nature conservancy to resolve potential liabilities for the three petroleum spills at the Edgewater, Lakeshore and Bay Shore plants. Following consideration of public comments, EPA will take action on the Final Orders.

In October 2009, the WVDEP issued an NPDES water discharge permit for the Fort Martin Plant, which imposes TDS, sulfate concentrations and other effluent limitations for heavy metals, as well as temperature limitations. Concurrent with the issuance of the Fort Martin NPDES permit, WVDEP also issued an administrative order setting deadlines for MP to meet certain of the effluent limits that were effective immediately under the terms of the NPDES permit. MP appealed, and a stay of certain conditions of the NPDES permit and order have been granted pending a final decision on the appeal and subject to WVDEP moving to dissolve the stay. The Fort Martin NPDES permit could require an initial capital investment in excess of $150 million in order to install technology to meet the TDS and sulfate limits, which technology may also meet certain of the other effluent limits. Additional technology may be needed to meet certain other limits in the Fort Martin NPDES 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.

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, AE Supply 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 May 2011, the West Virginia Highlands Conservancy, the West Virginia Rivers Coalition, and the Sierra Club filed a CWA citizen suit in the U.S. District Court for the Northern District of West Virginia 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. 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. MP filed an answer on July 11, 2011, and a motion to stay the proceedings on July 13, 2011. In April 2012, the parties reached a settlement to resolve these CWA citizen suit claims for an immaterial amount. On August 14, 2012, a Consent Decree was entered by the Court resolving these claims. MP is currently seeking relief from the arsenic limits through a WVDEP agency review.

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.

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 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. On July 27, 2012, the PA DEP filed a complaint against FG in the U.S. District Court for the Western District of Pennsylvania with claims under the Resource Conservation and Recovery Act and Pennsylvania's Solid Waste Management Act regarding the LBR CCB Impoundment and simultaneously proposed a Consent Decree between PA DEP and FG to resolve those claims. On December 14, 2012, a modified Consent Decree that addresses public comments received by PA DEP was entered by the court, requiring FG to conduct monitoring, studies and submit a closure plan to the PA DEP, no later than March 31, 2013, and discontinue disposal to LBR as currently permitted by December 31, 2016. The modified Consent

Decree also requires payment of civil penalties of $800,000 to resolve claims under the Solid Waste Management Act. On January 23, 2013, FG announced a plan to ship the CCBs from the Bruce Mansfield Plant to the LaBelle coal mine reclamation project. On February 1, 2013, FG submitted a Feasibility Study analyzing various technical issues relevant to the closure of LBR. The Feasibility Study estimated that viable options for placing a final cap over LBR would require between 6 to 16 years with an estimated cost ranging from $78 million to $224 million. The Bruce Mansfield Plant is pursuing several options for its CCBs following December 31, 2016, including beneficial use of CCBs for mine reclamation in LaBelle, Pennsylvania. On December 20, 2012, the Environmental Integrity Project and others served FG with a citizen suit notice alleging CWA and PA Clean Streams Law Violations at LBR. At least 60 days must pass before a complaint can be filed.

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.

Certain of FirstEnergy's utilities have been named as potentially responsible parties at waste disposal sites, which may require cleanup under the CERCLA. 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, 2012, based on estimates of the total costs of cleanup, FE's and its subsidiaries' proportionate responsibility for such costs and the financial ability of other unaffiliated entities to pay. Total liabilities of approximately $124 million (including $88 million applicable to JCP&L) have been accrued through December 31, 2012. Included in the total are accrued liabilities of approximately $81 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. FirstEnergy 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 27.3 million tons of coal for the year 2013 which is approximately 86% of its estimated 2013 coal requirements of 32.1 million tons. 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 - Hazardous Air Pollutant Emissions” for information regarding deactivations of certain coal-fired generating units in response to increased environmental regulations and the impact on certain coal transportation contracts.

FirstEnergy has contracts for all uranium requirements through 2014 and a portion of uranium material requirements through 2024. Conversion services contracts fully cover requirements through 2015 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 2013. 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 completed in December 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. NG 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. 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 combustion turbine units, 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 combustion turbine units and peaking units, and demand is forecasted at less than 7 million mcf in 2013.

System Demand

The 2012 maximum hourly demand for each of the Utilities was:

- OE—5,809 MW on July 17, 2012;
- Penn—923 MW on July 17, 2012;
- CEI—4,337 MW on July 17, 2012;
- TE—2,445 MW on July 17, 2012;
- JCP&L—6,190 MW on July 18, 2012;
- ME—3,036 MW on July 18, 2012;
- PN—2,852 MW on July 18, 2012;

- MP—1,848 MW on June 29, 2012;
- PE—2,872 MW on June 29, 2012; and
- WP—3,804 MW on June 29, 2012

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. Default service for the Ohio Companies, Pennsylvania Companies and PE's Maryland jurisdiction 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 LSE. 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 and AE Supply provide the power requirements of their 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 their 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 FERC. RFC began operations under the NERC on January 1, 2006. On July 20, 2006, the NERC was certified by 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 end users, and (3) in the wholesale market.

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 those times. 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, FG 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 R&D 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 as of February 25, 2013

Name	Age	Positions Held During Past Five Years	Dates
A. J. Alexander	61	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	61	Senior Vice President, Human Resources (B)	*-present
		Senior Vice President, Human Resources (H)	2011-present
M. T. Clark	62	Executive Vice President, Finance and Strategy (A)(B)(C)(D)(E)(F)(H)(I)(J)(K)(L)	2013-present
		President (G)	2013-present
		President and Chief Financial Officer (G)	2012
		Executive Vice President and Chief Financial Officer (A)(B)(C)(D)(E)(F)(L)	2009-2012
		Executive Vice President and Chief Financial Officer (H)(I)(J)(K)	2011-2012
		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	48	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)	*-2008
B. L. Gaines	59	Senior Vice President, Corporate Services and Chief Information Officer (B)(H)	2012-present
		Vice President, Corporate Services and Chief Information Officer (B)(H)	2011-2012
		Vice President, Shared Services, Administration and Chief Information Officer (B)	2009-2011
		Vice President, Information Technology and Corporate Security and Chief Information Officer (B)	*-2009
C. E. Jones	57	Senior Vice President & President, FirstEnergy Utilities (H)	2011-present
		Senior Vice President & President, FirstEnergy Utilities (B)	2010-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
		Senior Vice President (C)(D)	2009-2010
		President (E)	*-2009
		President (L)	*-2008
J. H. Lash	62	President, FE Generation (B)(H)	2011-present
		President (I)(L)	2011-present
		Chief Nuclear Officer (F)	2011-2012
		President and Chief Nuclear Officer (F)	2010-2011
		President, FirstEnergy Nuclear Operating Company (B)	2010-2011

		Senior Vice President and Chief Operating Officer (F)	*-2010
J. F. Pearson	58	Senior Vice President and Chief Financial Officer (A)(B)(C)(D)(E)(F)(G)(H)(I)(J)(K)(L)	2013-present
		Senior Vice President and Treasurer (A)(B)(C)(D)(E)(F)(G)(H)(I)(J)(K)(L)	2012
		Vice President and Treasurer (A)(B)(C)(D)(E)(F)(L)	*-2012
		Vice President and Treasurer (G)(H)(I)(J)(K)	2011-2012
D. R. Schneider	51	President (E)	2009-present
		Senior Vice President, Energy Delivery & Customer Service (B)	*-2009
		Senior Vice President (C)(D)	*-2009
L. L. Vespoli	53	Executive Vice President and General Counsel (A)(B)(C)(D)(E)(F)(L)	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)(L)	*-2008
H. L. Wagner	60	Vice President, Controller and Chief Accounting Officer (A)	*-present
		Vice President and Controller (C)(D)(E)(F)(L)	*-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, 2008	(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) Denotes executive officer of FE Generation
(C) Denotes executive officer of OE, CEI and TE	(H) Denotes executive officer of AESC	
(D) Denotes executive officer of ME, PN and Penn	(I) Denotes executive officer of AGC	

The following are the Executive Officers of JCP&L: M.A. Barwood, Controller since 2012 (age 55); D. M. Lynch, President since 2009 (age 58); E.J. Udovich, Corporate Secretary since 2008 (age 57); W. Wang, Treasurer since 2012 (age 41).

Employees

As of December 31, 2012, FirstEnergy’s subsidiaries had 16,495 employees located in the United States as follows:

	Total Employees	Bargaining Unit Employees
FESC	3,881	554
OE	1,190	752
CEI	885	594
TE	373	275
Penn	207	156
JCP&L	1,410	1,091
ME	697	512
PN	838	578
ATSI	37	—
FES	276	—
FG	2,377	1,484
FENOC	2,627	947
MP	538	324
PE	449	283
WP	710	474
Total	16,495	8,024

As of December 31, 2012, the IBEW, the UWUA and the OPEIU unions collectively represented approximately 48% of FirstEnergy's total employees. There are various collective bargaining agreements between FirstEnergy's subsidiaries and these unions with three to five year terms. There are seven agreements that cover approximately 2,850 bargaining unit employees that expire in 2013.

FirstEnergy Web Site

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

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

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 Registrants' 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. 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 requirements 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 operation 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 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 sales obligations. Moreover, if we were unable to perform under contractual obligations, including but not limited to, our coal and coal transportation contracts, penalties or liability for damages could result.

FES, FG 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, FG and the Ohio Companies have a maximum exposure to loss under those provisions of approximately $1.3 billion for FES, $545 million for OE and an aggregate of $303 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 harm our business reputation and 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 Including, but Not Limited to Natural Gas, Could Adversely Affect Our Profit Margins

We purchase and sell electricity in the competitive retail and wholesale markets. Increases in the costs of fuel for our generation facilities (particularly coal, uranium and natural gas) can affect our profit margins. Competition and 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 decreasing sales margins or increasing the amount we pay to purchase power to satisfy our sales obligations in the states we do business. We are exposed to risk from the volatility of the market price of natural gas. Our ability to sell at a profit is highly dependent on the price of natural gas. As the price of natural gas falls, other market participants that utilize natural gas-fired generation will be able to offer electricity at increasingly competitive prices, so the margins we realize from sales will be lower and, on occasion, we may need to curtail operation of marginal plants. The availability of natural gas and issues related to its accessibility may have a long-term material impact on the price of natural gas. 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 for a variety of reasons, including:

- changing weather conditions or seasonality;
- changes in electricity usage by our customers caused in part by energy and efficiency mandates and demand response initiatives;
- 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, including but not limited to, coal, natural gas and oil;
- changes in power production capacity;
- outages, deactivations and retirements at our power production facilities or those of our competitors;
- changes in production and storage levels of natural gas, such as that which could result from the natural gas produced in the Marcellus and Utica regions, lignite, coal, crude oil and refined products resulting in over or under supply;
- 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 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

The Wall Street Reform and Consumer Protection Act (Dodd-Frank) was enacted into law in July 2010 with the primary objective of increasing oversight of the United States financial system including the regulation of most financial transactions, swaps and derivatives. Dodd-Frank requires CFTC and SEC rulemaking to implement its provisions. Although the CFTC and the SEC have completed some of its rulemaking, a significant amount of rulemaking remains.

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. The overall impact of those regulations may be reduced but not eliminated for companies that participate in the swap market as "end-users" for hedging purposes. If we are determined to be a swap dealer or a major swap participant, we will be required to commit substantial additional capital toward collateral costs to meet the margin requirements of the major exchanges, comply with increased reporting and record-keeping requirements and follow CFTC-specified business conduct standards.

Even if we are not determined to be a swap dealer or a major swap participant, as an end-user, we are required to comply with additional regulatory obligations under Dodd-Frank, which includes record-keeping, reporting requirements and the clearing of some transactions that we would otherwise enter into over-the-counter. Also, the total burden that the rules could impose on all market participants could cause liquidity in the bilateral OTC swap market to decrease. The new rules could impede our ability to meet our hedge targets in a cost-effective manner. FirstEnergy cannot predict the ultimate impact Dodd-Frank rulemaking 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 adversely affected 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 spent fuel storage and decommissioning nuclear plants, including but not limited to, waste disposal, 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 Affect Our Business and Financial Condition" below and Note 15, Commitments, Guarantees and Contingencies - Environmental Matters of the Combined Notes to Consolidated Financial Statements.

The Outcome of Litigation, Arbitration, Mediation, and Similar Proceedings, Involving Our Business, or That of One or More of Our Operating Subsidiaries, is Unpredictable and an Adverse Decision in Any Material Proceeding Could Have a Material Adverse Effect on Our Financial Position and Results of Operations.

We are involved in a number of litigation, arbitration, mediation, and similar proceedings including, but not limited to, dealing with our fuel and fuel transportation contracts. These matters may divert financial and management resources that would otherwise be used to benefit our operations. No assurances can be given that the results of these matters will be favorable to us. An adverse resolution of any of these material matters could have an adverse material impact on our financial position and results of operations. In addition, we are sometimes subject to investigations and inquiries by various state and federal regulators due to the heavily regulated nature of our industry. Any material inquiry or investigation could potentially result in an adverse ruling against us, which could have an adverse material impact on our financial position and operating results.

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 60% 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, HCL and various metals effective in April 2015, the EPA proposed regulations that include an option to reclassify coal combustion residuals as a "special" 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. Certain of the assets held in these trusts do not have readily determinable market values. Changes in the estimates and assumptions including, but not limited to the discount rate, 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

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 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. NERC, RFC and FERC can be expected to continue to refine existing reliability standards as well as develop and adopt new reliability standards. 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. FERC has authority to impose penalties up to and including $1.0 million per day for failure to comply with these mandatory electric reliability standards.

In addition to direct regulation by 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 FERC, they can impose rules, restrictions and terms of service which 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, PJM may direct our transmission-owning affiliates to build new transmission facilities to meet PJM's reliability requirements or to provide new or expanded transmission service under the PJM open access transmission tariff.

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 and RTOs, 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 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 PJM or FERC requiring us to upgrade or expand our transmission system, requiring additional capital expenditures.

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 ISOs or RTOs 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, such as Hurricane Sandy, 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 and could have an adverse effect on our financial condition and results of operations. 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. A significant decrease in demand, resulting from factors including but not limited to increased customer shopping, more stringent energy efficiency mandates and increased demand response initiatives could cause a decrease in the market price of power. 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 substantially impacted by the same economic conditions.

Increases in 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 and Could Have an Adverse Effect on Our Results of Operations

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, natural gas or other commodity prices, 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 and the failure to retain or attract trained and qualified labor could have an adverse effect on our business.

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 recent 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, discount 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.

FirstEnergy recognizes in income the change in the fair value of plan assets and net actuarial gains and losses for its defined Pension and OPEB plans. This adjustment is recognized in the fourth quarter of each year and whenever a plan is determined to qualify for a remeasurement, which could result in greater volatility in pension and OPEB expenses and may materially impact our results of operations under GAAP.

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 and Regulatory Policies 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 or changes in regulatory policies will reduce costs of new technology 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.

Certain FirstEnergy Companies May Not be Able 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 and damage our reputation, which could have an adverse impact on our business.

Risks Associated With Regulation

Complex and Changing Government Regulations, Including Those Associated With Rates and Pending Rate Cases 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 be decreased as a result of actions taken by one or more of the state regulatory commissions in which our utility subsidiaries operate. Also, these rates may not be set to recover the Utility's 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. For example, the PUCO and PPUC have recently instituted investigations in Ohio and Pennsylvania, respectively, to evaluate the vitality of, and to make recommendations for improvements to, the competitive retail markets in those states. 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.

FERC and the U.S. Congress propose changes from time to time in the structure and conduct of the electric utility industry. If any 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 that 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

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, as well as, waivers of the requirements to obtain FERC approval for issuances of securities. FERC's orders that grant this market-based rate authority reserve the right to revoke or revise that authority if 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 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 the 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 Efficiency and Peak Demand Reduction Mandates 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 where we operate. In New Jersey, we recover the costs for energy efficiency programs through the SBC. Currently only our Ohio Companies recover 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 adversely 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

As a result of a 2012 comprehensive review of FirstEnergy's coal-fired generating facilities in light of the recently finalized MATS rules and other expanded environmental requirements, we deactivated sixteen older coal-fired generating units in 2012, and intend to deactivate five additional older coal-fired generating units when RMR requirements terminate. We may be forced to shut down other facilities or change their operating status, either temporarily or permanently, if we are unable to comply with these or other existing or new 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 generation facilities to the far more stringent new source standards applicable to new generation 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 15, Commitments, Guarantees and Contingencies - Environmental Matters of the Combined Notes to 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, emissions 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 including, but not limited to MATS, 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, including but not limited to, our assumptions regarding estimated compliance costs, 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 CO_2 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. 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 15, Commitments, Guarantees and Contingencies - Environmental Matters of the Combined

Notes to 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, Including but not Limited to MATS, Could be
Substantial and Result in Significant Changes to Our Operations

On December 21, 2011, the EPA finalized the MATS to establish emission standards for, among other things, mercury, HCL and various metals, for electric generating units. The costs associated with MATS compliance, and other environmental laws, is substantial and contributed to the Company's decision to deactivate nine older coal-fired generating plants. MATS is also being challenged by numerous entities, including FG, in the United States Court of Appeals for the District of Columbia. Depending on the outcome of these legal proceedings and how MATS and other EPA emission regulations are ultimately implemented, MP's, FG's and AE Supply's future cost of compliance may be substantial and changes to FirstEnergy's operations may result. FirstEnergy's future cost of compliance with such regulations may be substantial and additional changes to FirstEnergy's operations may result.

See Note 15, Commitments, Guarantees and Contingencies - Environmental Matters of the Combined Notes to 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 CWA 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 CWA 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 systems. 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 15, Commitments, Guarantees and Contingencies - Environmental Matters of the Combined Notes to 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. See Note 15, Commitments, Guarantees and Contingencies - Environmental Matters of the Combined Notes to the Consolidated Financial Statements.

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 emission controls. As we use the emission 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 REC purchase costs, purchased power and capital expenditures. Any such changes may have an adverse effect 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 Affect Our Business and Financial Condition

As a result of the NRC's investigation of the incident at the Fukushima Daiichi nuclear plant, the NRC has begun 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. The NRC has also issued orders and guidance that increases procedural and testing requirements, requires physical modifications to our plants and is expected to increase future compliance and operating costs. 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.

Increases in Taxes and Fees May Adversely Affect 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, or 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 Relating to U.S. Fiscal Policy 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 foreign or domestic financial institutions or foreign governments 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 or Our Subsidiaries' Financing Costs, Ability to Access Capital and Requirement to Post Collateral and the Ability to Continue Successfully Implementing Our Retail Sales Strategy

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 or our subsidiaries' 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. A downgrade in our credit rating, or that of our subsidiaries, could also preclude certain retail customers from executing supply contracts with us and therefore impact our ability to successfully implement our retail sales strategy. 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 15, Commitments, Guarantees and Contingencies - Guarantees and Other Assurances of the Combined Notes to Consolidated Financial Statements for more information associated with a credit ratings downgrade leading to the posting of cash collateral.

The Stability 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 in short-term investments. Our ability to access our cash quickly depends on the stability 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 first mortgage indentures for OE, Penn, FG and NG 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 5, Leases, and 11, Capitalization of the Combined Notes to Consolidated Financial Statements for information concerning leases and financing encumbrances affecting certain of the Utilities’, FG’s and NG’s properties.

As of September 1, 2012, the following coal-fired power plants, which collectively include sixteen generating units, were deactivated: Albright, Armstrong, Bay Shore Units 2-4, Eastlake Units 4-5, R. Paul Smith, Rivesville and Willow Island. Five additional generating units, Ashtabula, Eastlake Units 1-3, and Lake Shore will remain active pursuant to RMR arrangements with PJM until their anticipated deactivation, which is expected in the spring of 2015.

FirstEnergy controls the following generation sources as of January 31, 2013, shown in the table below. Except for the leasehold interests, OVEC participation and wind and solar power arrangements referenced in the footnotes to the table, substantially all of FES' competitive generating units are owned by NG (nuclear) and FG (non-nuclear); the regulated generating units are owned by JCP&L and MP.

Plant (Location)	Unit	Total[1]	Competitive FES	AE Supply	Regulated
		Net Demonstrated Capacity (MW)			
Super-critical Coal-fired:					
Bruce Mansfield (Shippingport, PA)	1	830	830	—	—
Bruce Mansfield (Shippingport, PA)	2	830	830	—	—
Bruce Mansfield (Shippingport, PA)	3	830	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
		9,791	3,690	4,486	1,615
Sub-critical and Other Coal-fired:					
W. H. Sammis (Stratton, OH)	1-5	1,020	1,020	—	—
Eastlake (Eastlake, OH)	1-3	396 [2]	396	—	—
Bay Shore (Toledo, OH)	1	136	136	—	—
Mitchell (Courtney, PA)	3	288	—	288	—
Lakeshore (Cleveland, OH)	18	245 [2]	245	—	—
Ashtabula (Ashtabula, OH)	5	244 [2]	244	—	—
OVEC (Cheshire, OH) (Madison, IN)	1-11	188 [3]	110	67	11
		2,517	2,151	355	11
Nuclear:					
Beaver Valley (Shippingport, PA)	1	911	911	—	—
Beaver Valley (Shippingport, PA)	2	904 [4]	904	—	—
Davis-Besse (Oak Harbor, OH)	1	908	908	—	—
Perry (N. Perry Village, OH)	1	1,268 [5]	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 [6]	—	43	—
Other		216	216	—	—
		1,745	761	984	—
Pumped-storage and Hydro:					
Bath County (Warm Springs, VA)	1-6	1,110 [7]	—	660	450
Seneca (Warren, PA)	1-3	451	451	—	—
Yard’s Creek (Blairstown Twp., NJ)	1-3	200 [8]	—	—	200

Lake Lynn (Lake Lynn, PA)	1-4	52	(9)	—	52	—
Other		19		—	19	—
		1,832		451	731	650
Wind and Solar Power		496	(10)	496	—	—
Total		20,372		11,540	6,556	2,276

(1) Does not include 16 units deactivated in 2012.
(2) Remains active pursuant to RMR arrangements with PJM.
(3) Represents FG's 4.85%, AE Supply's 3.01% and MP's 0.49% entitlement based on their participation in OVEC.
(4) Includes OE's leasehold interest of 8.67% (78 MW) from non-affiliates.
(5) Includes OE's leasehold interest of 8.11% (103 MW) from non-affiliates.
(6) 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.
(7) Represents capacity entitlement through ownership of AGC.
(8) Represents JCP&L's 50% ownership interest.
(9) AE Supply has a license for Lake Lynn through 2024.
(10) Includes 167 MW from leased facilities and 329 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. FirstEnergy's overhead and underground transmission lines aggregate 24,008 pole miles.

The Utilities' electric distribution systems include 266,757 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 144,776,431 kV-amperes.

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

FirstEnergy's distribution and transmission systems as of December 31, 2012, consist of the following:

	Distribution Lines[1]	Transmission Lines[1]	Substation Transformer Capacity[2] kV Amperes
OE	62,292	468	7,461,803
Penn	13,448	52	1,033,620
CEI	33,278	—	9,936,146
TE	17,591	81	2,934,533
JCP&L	22,887	2,569	22,848,766
ME	18,718	1,422	10,727,900
PN	27,213	3,163	14,996,909
ATSI[3]	—	7,487	25,631,174
WP	24,452	4,215	16,027,665
MP	21,590	2,251	15,008,481
PE	25,288	2,119	13,967,434
TrAIL[4]	—	181	4,202,000
Total	266,757	24,008	144,776,431

(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 line 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 15, Commitments, Guarantees and Contingencies of the Combined Notes to Consolidated Financial Statements for a description of certain legal proceedings involving FirstEnergy, FES, OE and JCP&L.

ITEM 4. MINE SAFETY DISCLOSURE

Not applicable

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, and JCP&L 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 2013 proxy statement to be filed with the SEC pursuant to Regulation 14A under the Securities Exchange Act.

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On January 2, 2013, 3,024 shares of common stock of FE were issued in connection with a director deferred compensation plan of AE in a transaction not involving a public offering in reliance on the exemption from registration afforded by Section 4(a)(2) of the Securities Act of 1933, as amended, based upon the recipient's (i) status as an "accredited investor" under Regulation D thereunder and (ii) access to information about FE.

The table below includes information regarding purchases of FE common stock during the fourth quarter of 2012:

	Period			
	October	November	December	Fourth Quarter
Total Number of Shares Purchased[1]	77,764	55,763	594,764	728,291
Average Price Paid per Share	$45.10	$42.51	$42.17	$42.51
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,	2012	2011	2010	2009	2008
	(In millions, except per share amounts)				
Revenues	$15,303	$16,147	$13,339	$12,973	$13,627
Earnings Available to FirstEnergy Corp.	$770	$885	$742	$872	$623
Earnings per Share of Common Stock:					
Basic	$1.85	$2.22	$2.44	$2.87	$2.05
Diluted	$1.84	$2.21	$2.42	$2.85	$2.03
Weighted Average Shares Outstanding:					
Basic	418	399	304	304	304
Diluted	419	401	305	306	307
Dividends Declared per Share of Common Stock	$2.20	$2.20	$2.20	$2.20	$2.20
Total Assets	$50,406	$47,326	$35,531	$35,054	$34,206
Capitalization as of December 31:					
Total Equity	$13,093	$13,299	$8,952	$9,014	$8,748
Long-Term Debt and Other Long-Term Obligations	15,179	15,716	12,579	12,008	9,100
Total Capitalization	$28,272	$29,015	$21,531	$21,022	$17,848

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.

	2012		2011	
	High	Low	High	Low
First Quarter	$46.59	$40.37	$40.80	$36.11
Second Quarter	$49.46	$44.64	$45.80	$36.50
Third Quarter	$51.14	$42.05	$46.51	$38.77
Fourth Quarter	$46.55	$40.47	$46.10	$41.55
Yearly	$51.14	$40.37	$46.51	$36.11

Closing prices are from http://finance.yahoo.com.

SHAREHOLDER RETURN

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The following graph shows the total cumulative return from a $100 investment on December 31, 2007 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 109,313 and 108,933 holders of 418,216,437 shares of FirstEnergy’s common stock as of December 31, 2012 and January 31, 2013, respectively. Information regarding retained earnings available for payment of cash dividends is given in Note 11, Capitalization of the Combined Notes to 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, in general, and the retail sales market in particular.
- 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 and pending rate cases.
- The uncertainties of various cost recovery and cost allocation issues resulting from ATSI's realignment into PJM.
- Economic or weather conditions affecting future sales and margins.
- Regulatory outcomes associated with Hurricane Sandy.

- Changing energy, capacity and commodity market prices including, but not limited to, coal, natural gas and oil, and availability and their impact on retail margins.
- Financial derivative reforms that could increase our liquidity needs and collateral costs.
- The continued ability of our 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 discharge, water intake and coal combustion residual regulations, the potential impacts of CAIR, and any laws, rules or regulations that ultimately replace CAIR, and the effects of the EPA's MATS rules including our estimated costs of compliance.
- 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 deactivate or idle certain generating units).
- The uncertainties associated with the deactivation of certain older unscrubbed regulated and competitive fossil units, including the impact on vendor commitments, and the timing thereof as they relate to, among other things, the RMR arrangements and the reliability of the transmission grid.
- 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 or as a result of the incident at Japan's Fukushima Daiichi Nuclear Plant).
- Adverse legal decisions and outcomes related to ME's and PN's ability to recover certain transmission costs through their TSC riders.
- The impact of future changes to the operational status or availability of our generating units.
- The risks and uncertainties associated with litigation, arbitration, mediation and like proceedings, including, but not limited to, any such proceedings related to vendor commitments.
- Replacement power costs being higher than anticipated or inadequately hedged.
- The ability to comply with applicable state and federal reliability standards and energy efficiency and peak demand reduction mandates.
- Changes in customers' demand for power, including but not limited to, changes resulting from the implementation of state and federal energy efficiency and peak demand reduction mandates.
- The ability to accomplish or realize anticipated benefits from strategic and financial goals including, but not limited to, the ability to successfully complete the proposed West Virginia asset transfer and to improve our credit metrics.
- Our 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 Regulated Distribution segment and to continue to successfully implement our direct retail sales strategy in the Competitive Energy Services segment.
- Changing market conditions that could affect the measurement of liabilities and the value of assets held in our NDTs, pension trusts and other trust funds, and cause us and our 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 our financing plans, the cost of such capital and overall condition of the capital and credit markets affecting us and our subsidiaries.
- Actions that may be taken by credit rating agencies that could negatively affect us and our subsidiaries' access to financing, increase the costs thereof, and increase requirements to post additional collateral to support outstanding commodity positions, LOCs and other financial guarantees.
- Changes in national and regional economic conditions affecting us, our subsidiaries and our major industrial and commercial customers, and other counterparties including fuel suppliers, with which we do business.
- Issues concerning the stability of domestic and foreign financial institutions and counterparties with which we do business.
- The risks and other factors discussed from time to time in our 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 2012 were $770 million, or basic earnings of $1.85 per share of common stock ($1.84 diluted), compared with $885 million, or basic earnings of $2.22 per share of common stock ($2.21 diluted) in 2011 and $742 million, or $2.44 per basic share ($2.42 diluted), in 2010. The principal reasons for the changes in basic earnings per share are summarized below.

Change In Basic Earnings Per Share From Prior Year	2012	2011
Basic Earnings Per Share - Prior Year	$2.22	$2.44
Segment operating results[1] -		
Regulated Distribution	(0.03)	(0.01)
Regulated Transmission	—	(0.06)
Competitive Energy Services	(0.22)	(0.15)
Regulatory charges	(0.03)	0.03
Merger-related costs	0.36	(0.29)
Merger accounting — commodity contracts	0.11	(0.26)
Net merger accretion[1][2]	0.01	0.54
Impact of non-core asset sales / impairments	(0.78)	0.67
Trust securities impairments	0.01	0.02
Mark-to-market adjustments-		
Pension and OPEB actuarial assumptions	(0.17)	(0.47)
All other	0.13	0.02
Plant closing costs	(0.29)	—
Generating plant charges	0.49	0.08
Litigation resolution	0.06	(0.07)
Debt redemption costs	—	(0.01)
Restructuring costs	(0.02)	—
Depreciation	(0.01)	(0.03)
Interest expense, net of amounts capitalized	0.04	(0.14)
Investment income	(0.01)	(0.03)
Income tax legislative changes	(0.02)	(0.03)
Change in effective tax rate	(0.09)	0.04
Settlement of uncertain tax positions	0.06	(0.05)
Other	0.03	(0.02)
Basic Earnings Per Share	$1.85	$2.22

(1) Excludes amounts that are shown separately.

(2) Includes dilutive effect of shares issued in connection with the Allegheny merger and twelve months of Allegheny results in 2012 compared to ten months during the same period of 2011.

FirstEnergy has taken a series of actions that are intended to offset the impact on its results of operations of the continued weak economy and current trend of weak power prices, including operational changes at certain power plants, staffing reductions resulting from a recently-conducted organizational study, a plan to limit hiring to fill open positions resulting from normal attrition in 2013, and employee and retiree benefit changes and cost reduction initiatives across all business units. FirstEnergy will continue to evaluate and implement these and other initiatives as necessary to improve results of operations.

FirstEnergy considers a variety of factors, including wholesale power prices, in its decision to operate, or not operate, a generating plant. If wholesale power prices represent a lower cost option, FirstEnergy may elect to fulfill its load obligation through purchasing electricity in the wholesale market as opposed to operating a generating unit. The effect of this decision on its results of operations would be to displace higher per unit fuel expense with lower per unit purchased power.

FirstEnergy engages in discussions with various vendors, from time to time, regarding the impact that these and other actions may have on certain of its long-term agreements and FirstEnergy cannot provide assurance that these discussions will be satisfactorily resolved.

In 2012 the organizational study referred to above was undertaken to determine how FirstEnergy's workforce should be aligned to best meet the challenges of the continued weak economy. The initiative included a review of corporate support departments and FES. As a result of the organizational study, approximately 200 positions were eliminated. Separately, FirstEnergy also expects further workforce reductions of approximately 300-400 occurring throughout 2013 as replacement of employees who leave the company through normal attrition will be limited. FirstEnergy incurred approximately $10 million of severance related expenses in the fourth quarter of 2012.

Operational Matters

Natural Gas Combustion Turbines at Eastlake

On November 5, 2012, FirstEnergy and AMP entered into a non-binding MOU to site, build, and operate a natural gas peaking facility located on the grounds of FirstEnergy's existing Eastlake Plant in Eastlake, Ohio. The proposed project is subject to regulatory approval. As part of the non-binding MOU, FirstEnergy would supervise construction of the four combustion turbine units that are capable of producing 873 MW. AMP will provide the construction financing and FirstEnergy will purchase a 25% interest upon completion. Plans call for the facility to be operation in early 2016.

Deactivations at Fossil Generation Plants

As of September 1, 2012, the following coal-fired power plants, which collectively include sixteen generating units, were deactivated: Albright, Armstrong, Bay Shore Units 2-4, Eastlake Units 4-5, R. Paul Smith, Rivesville and Willow Island. Five additional generating units, Ashtabula, Eastlake Units 1-3, and Lake Shore will remain active pursuant to RMR arrangements with PJM until their anticipated deactivation, which is expected in the spring of 2015.

Enhancing Transmission System Reliability

On May 29, 2012, FirstEnergy announced plans to construct a series of transmission projects to enhance service reliability across its service area. The projects have been approved by PJM and will include specialized voltage regulating equipment in northern Ohio. In addition to the work in Ohio, approved transmission projects will also be undertaken in Pennsylvania, West Virginia, New Jersey and Maryland as part of FirstEnergy's ongoing commitment to enhance its transmission system reliability. FirstEnergy estimates spending between $500 - 700 million through 2016 on these projects.

On June 14, 2012, JCP&L announced that it plans to begin work on 17 transmission construction projects over the next six months. These projects are part of a multi-year, $200 million LITE program, which began in 2011, to address New Jersey's growing demand for electricity and provide key enhancements to the transmission system designed to improve service reliability for JCP&L's 1.1 million customers. All of the LITE projects are being designed and built specifically to serve only JCP&L customers.

Nuclear Refueling Outages

The following table includes details for the three refueling outages in 2012:

Unit	Outage Start	Returned to Service	Outage Type
Beaver Valley Unit 1	April 9, 2012	May 11, 2012	Refueling & Maintenance
Davis-Besse	May 6, 2012	June 13, 2012	Refueling & Maintenance
Beaver Valley Unit 2	September 24, 2012	November 2, 2012	Refueling, Maintenance & Turbine Upgrade

Root Cause Analysis Completed for Davis-Besse

On February 28, 2012, FENOC announced it completed its Root Cause Analysis Report regarding the hairline cracks identified in portions of the Davis-Besse Shield Building during the fall 2011 reactor head replacement outage. The report was submitted to the NRC and concluded that based on extensive evaluation, the structural integrity of the shield building remains intact and the building is able to perform its safety function.

Beaver Valley Power Station to Expand Fuel Storage Capacity

On September 17, 2012, FENOC announced a plan to expand used nuclear fuel storage capacity at Beaver Valley Units 1 and 2. Under the plan, above-ground, airtight steel and concrete canisters will be installed to provide cooling, through natural air circulation, to used fuel assemblies. Initial installation will consist of six canisters and up to 47 additional canisters will be added as needed. Construction of the fuel storage system began in fall 2012, with completion planned for 2014. Certain costs incurred by FirstEnergy for this project are expected to be reimbursed by the DOE under a January 2012 settlement. Due to a change in NRC regulations, FirstEnergy is required to independently fund the radiological decommissioning of its independent spent fuel storage facilities.

Storm Costs

During the last weekend of June 2012, MP, PE, WP and OE experienced significant customer outages due to a rare "derecho" wind storm. Costs incurred related to this storm were approximately $137 million and approximately 71% of these expenditures were capital-related. Most of the remaining maintenance costs were deferred for future recovery.

In late October 2012, FE's subsidiaries experienced unprecedented damage in their respective service territories, including JCP&L, as a result of Hurricane Sandy. Total restoration costs incurred in 2012 for Hurricane Sandy are summarized below.

State	Total	Capital	Asset Removal	O&M Expense	Regulatory Accounting	Net Expense
New Jersey	$629	$354	154	$121	$268	$7
West Virginia	86	51	15	20	35	—
Pennsylvania	82	47	17	18	28	7
Ohio	35	16	6	13	19	—
Maryland	28	17	6	5	6	5
	$860	$485	$198	$177	$356	$19

Regulatory Matters

Ohio Electric Security Plan Update

On July 18, 2012, the PUCO approved the Ohio Companies' ESP allowing the Ohio Companies to essentially extend the terms of the current ESP for two additional years and establish electricity prices for their customers through May 31, 2016.

The approved ESP 3 plan will maintain the benefits from the current ESP including:
- Freezing current base distribution rates through May 31, 2016;
- Continuing to provide economic development and assistance to low-income customers for the two-year extension period at the levels established in the existing ESP;
- Providing Percentage of Income Payment Plan customers with a 6% generation rate discount;
- Continuing to provide power to shopping and to non-shopping customers as part of the market-based price set through an auction process; and
- Continuing Rider DCR that allows continued investment in the distribution system for the benefit of customers.

The approved ESP 3 plan provides additional benefits including:
- Securing generation supply for a longer period of time by conducting an auction for a three-year period rather than a one-year period, in October 2012 and January 2013, to mitigate any potential price spikes for FirstEnergy Ohio utility customers who do not switch to a competitive generation supplier; and
-

Extending the recovery period for costs associated with purchasing RECs mandated by SB 221 through the end of the new ESP 3 period. This is expected to initially reduce the monthly renewable energy charge for all FirstEnergy Ohio non-shopping utility customers by spreading out the costs over the entire ESP period.

The approved plan reflects the diverse interests and concerns of 19 signatories, including parties that represent residential, low-income, commercial and industrial customers, as well as competitive retail electric suppliers, schools and hospitals.

Ohio Companies' Alternative Energy Rider Hearing

On September 20, 2011 the PUCO opened a new docket to review the Ohio Companies' alternative energy recovery rider. The PUCO selected auditors to perform a financial and management audit, and final audit reports were filed with the PUCO on August 15, 2012. While generally supportive of the Ohio Companies' approach to procurement of RECs, the management/performance auditor recommended the PUCO examine, for possible disallowance, certain costs associated with the procurement of In-State All Renewable obligations that the auditor characterized as excessive. A hearing for this matter commenced on February 19, 2013.

PUCO Approves Ohio Securitization

On October 10, 2012, the PUCO approved the application of CEI, OE and TE for a financing order to securitize previously incurred costs that are currently being recovered from customers under certain PUCO-approved deferred recovery riders, with an estimated December 31, 2012 aggregate balance of approximately $436 million as set forth in the application. When the transactions are executed, the proceeds are expected to be used to assist the Ohio Companies in their planned debt reductions. On November 9, 2012, an application for rehearing was filed for the Ohio securitization transaction. The PUCO amended the financing order in part on December 19, 2012 by its Entry on Rehearing. On January 9, 2013, the PUCO issued an Entry Nunc Pro Tunc to correct certain errors contained in the Entry on Rehearing issued in December. The financing order became final on February 18, 2013.

JCP&L Rate Case Filing

On July 31, 2012, the NJBPU ordered JCP&L to file a base rate case using a historic 2011 test year by November 1, 2012 (later extended to December 9, 2012). The rate case petition was filed on November 30, 2012. In the filing JCP&L requested approval to increase its revenues by approximately $31.5 million and reserved the right to update the filing to include costs associated with the impact of Hurricane Sandy. The NJBPU has transmitted the case to the New Jersey Office of Administrative Law for further proceedings and an ALJ has been assigned. Evidentiary hearings in the matter are currently anticipated to commence in September, 2013. On February 22, 2013, JCP&L updated its filing to request recovery of $603 million of distribution-related Hurricane Sandy restoration costs, resulting in increasing the total revenues requested to approximately $112 million.

CSAPR Vacated

On August 21, 2012, the U.S. Court of Appeals for the District of Columbia struck down the EPA's CSAPR, and directed the EPA to continue administering CAIR, which CSAPR was meant to replace. CSAPR would have accelerated emission reductions of SO_2 and NO_X from power plants. The U.S. Court of Appeals for the District of Columbia Circuit denied the EPA's request for reconsideration of its ruling striking down CSAPR.

PJM Removes PATH Project from Expansion Plans

On August 24, 2012, the PJM Board of Managers canceled the PATH project, which it had originally suspended in February 2011. All applications for authorization to construct the project filed with state commissions have been withdrawn. As a result, approximately $62 million and approximately $59 million in costs incurred by PATH-Allegheny and PATH-WV, respectively, were reclassified from net property, plant and equipment to a regulatory asset for future recovery. On September 28, 2012, those companies requested authorization from FERC to recover the costs with a proposed return on equity of 10.9% (10.4% base plus 0.5% RTO membership) from PJM customers over the next five years. Several parties protested the request. On November 30, 2012, FERC issued an order denying the 0.5% return on equity adder for RTO membership and allowing the tariff changes enabling recovery of these costs to become effective on December 1, 2012 subject to settlement judge procedures and hearing if the parties do not agree to a settlement. The issues subject to settlement include the prudence of the costs, the base return on equity and the period of recovery. Depending on the outcome of a possible settlement or hearing, if settlement is not achieved, PATH-Allegheny and PATH-WV may be required to refund certain amounts that have been collected under their formula rate.

PATH-Allegheny and PATH-WV have requested rehearing of FERC's denial of the 0.5% return on equity adder for RTO membership; that request for rehearing remains pending before FERC. In addition, FERC has consolidated for settlement judge procedures and hearing purposes two formal challenges to the PATH formula rate annual updates submitted to FERC in June 2010 and June 2011. FirstEnergy cannot predict the outcome of these matters or estimate the possible loss or range of loss.

West Virginia Utilities File for Change in Generation Ownership

On November 16, 2012, MP and PE filed a proposal with the WVPSC that, if approved, would transfer full ownership of the Harrison Power Station to MP and full ownership of the Pleasants Power Station to AE Supply. This two-part transaction, if approved as filed, would provide FES and AE Supply with approximately $1.1 billion of cash which can be used to redeem debt. The proposed transfer also would implement a cost-effective plan to assist MP in meeting its energy and capacity obligations with its own generation resources, as a result of the net addition of 1,476 MW, eliminating the need to make additional electricity and capacity purchases from the spot market, which is expected to result in greater rate stability for MP's customers.

Lower Fuel Costs, Lower Rates for FirstEnergy's West Virginia Customers

The WVPSC issued an order lowering electric rates for the West Virginia customers of MP and PE beginning January 1, 2013. The decrease primarily reflects lower coal and purchased power costs during 2012.

Financial Matters

During 2012, FES remarketed or refinanced approximately $682 million of PCRBs. Of this amount, approximately $411 million related to PCRBs that were retired by the company in 2011.

On April 16, 2012, WP issued $100 million of FMBs through a private placement at a rate of 3.34%. These bonds have a maturity date of April 15, 2022, and the proceeds were used in part to retire $80 million of 6.625% medium term notes that matured on April 16, 2012.

On April 16, 2012, AE Supply retired $503.2 million of 8.25% medium term notes at maturity.

On May 8, 2012, FET entered into a new $1 billion revolving credit facility. In conjunction with this action, an existing $450 million TrAIL revolving credit facility was terminated. On May 9, 2012, FET drew the entire amount to repay $171.3 million of short-term borrowings and to pay $3.2 million in expenses related to the closing. The balance was invested in the unregulated money pool. On May 10, 2012, FE repaid $1.0 billion under the existing $2.0 billion facility. Additionally, FirstEnergy and FES/AE Supply amended their existing $2.0 billion and $2.5 billion revolving credit facilities, respectively. The termination date on both facilities was extended from June 2016 to May 2017 and pricing was reduced to reflect current market conditions.

During 2012, FirstEnergy terminated $1.6 billion of forward starting interest rate swap agreements resulting in a net gain and cash proceeds of approximately $6 million. FirstEnergy has no interest rate swaps outstanding as of December 31, 2012.

During 2012, NG repurchased lessor equity interests in OE's existing sale and leaseback of Beaver Valley Unit 2 for $129 million and FG acquired certain equity or other interests in connection with the 1987 Bruce Mansfield Plant sale and leaseback transactions for $262.2 million.

On December 31, 2012, FE extended the stated maturity of a $150 million variable-rate term loan from April 7, 2013 to December 31, 2014.

FIRSTENERGY’S BUSINESS

During 2012, FirstEnergy completed the integration of Allegheny into its IT business networks and financial systems. An important element of this system integration was the capability of modifying the segment reporting to reflect how management now views and makes investment decisions regarding the distribution and transmission operations of FirstEnergy. The external segment reporting is consistent with the internal financial reports used by FirstEnergy's chief executive officer (its chief operating decision maker) to regularly assess the performance of the business and allocate resources. Disclosures for FirstEnergy's operating segments for 2011 and 2010 have been reclassified to conform to the current presentation.

The key changes in FirstEnergy's reportable segments during 2012 consisted principally of including the federally-regulated transmission assets and operations of JCP&L, ME, PN, MP, PE and WP, that were previously reported within the Regulated Distribution segment, with the renamed Regulated Transmission segment. There were no changes to the Competitive Energy Services or Other/Corporate Segments. FirstEnergy continues to have three reportable operating segments — Regulated Distribution, Regulated Transmission and Competitive Energy Services. Financial information for each of FirstEnergy’s reportable segments is presented in the tables below, which includes financial results for Allegheny beginning February 25, 2011. FES, OE and JCP&L do not have separate reportable operating segments.

The Regulated Distribution segment distributes electricity through FirstEnergy’s ten utility operating companies, serving approximately 6 million customers within 65,000 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 regulated electric generation facilities in West Virginia and New Jersey that 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, and customers served by, our regulated distribution utilities are summarized below (in thousands):

Company	Area Served	Customers Served
OE	Central and Northeastern Ohio	1,032
Penn	Western Pennsylvania	161
CEI	Northeastern Ohio	745
TE	Northwestern Ohio	308
JCP&L	Northern, Western and East Central New Jersey	1,099
ME	Eastern Pennsylvania	554
PN	Western Pennsylvania	590
WP	Southwest, South Central and Northern Pennsylvania	717
MP	Northern, Central and Southeastern West Virginia	387
PE	Western Maryland and Eastern West Virginia	390
		5,983

The Regulated Transmission segment, previously known in part as the Regulated Independent Transmission Segment, transmits electricity through transmission facilities owned and operated by ATSI, TrAIL, certain of FirstEnergy's utilities (JCP&L, ME, PN, MP, PE and WP) and the abandoned plant regulatory asset of PATH. The segment's revenues are primarily derived from rates that recover costs and provide a return on transmission capital investment. Except for the recovery of the PATH abandoned plant regulatory asset, these revenues are derived from transmission services provided pursuant to the PJM open access transmission tariff to electric energy providers, power marketers and revenue from operating the FirstEnergy transmission facilities. Its results reflect the net transmission expenses related to the delivery of electricity on FirstEnergy's transmission facilities.

The Competitive Energy Services segment, through FES and AE Supply, supplies electricity 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 the Utilities. This business segment controls approximately 18,000 MWs of capacity (including 885 MWs of capacity subject to RMR arrangements with PJM) 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.

The Competitive Energy Services segment derives its revenues from the sale of generation to direct and governmental aggregation, POLR and wholesale customers. The segment is exposed to various market and financial risks, including the risk of price fluctuations in the wholesale power markets. Wholesale power prices may be impacted by the prices of other commodities, including coal and natural gas, and energy efficiency and demand response programs, as well as regulatory and legislative actions, such as MATS among other factors. The segment attempts to mitigate the market risk inherent in its energy position by economically hedging its exposure and continuously monitoring various risk measurement metrics to ensure compliance with its risk management policies.

The Competitive Energy Services segment economically hedges exposure to price risk on a ratable basis, which is intended to reduce the near-term financial impact of market price volatility. As of December 31, 2012, the percentage of expected physical sales economically hedged was 89% for 2013 (out of the 104 million MWH target).

Other and Reconciling Adjustments contains corporate items and other businesses that are below the quantifiable threshold for separate disclosure as a reportable segment as well as reconciling adjustments for the elimination of intersegment transactions. See Note 18, Segment Information, of the Combined Notes to 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.

Through a series of several strategic mergers and asset transactions over the past fifteen years, the most recent of which was completed in February 2011, FirstEnergy has grown its diverse and sizeable asset base. We are now uniquely positioned as the nation's largest contiguous electric system with complementary assets across our generation, transmission and distribution operations. These assets are in a prime location within PJM, the largest competitive electricity market in the United States.

Combined, our regulated distribution and transmission operations provide a solid foundation, with strong and stable cash flows to support our dividend. Our competitive operations are expected to provide a growth platform.

Our regulated distribution segment continues to see the effects of a stagnant economy and slow economic recovery, with distribution delivery volumes to residential, commercial and industrial customers flat to slightly negative, depending on location, since 2007. We expect modest growth of one half of one percent across our distribution utility footprint in 2013. Longer term, we plan to capitalize on our prime location within the Marcellus and Utica shale region by focusing on supporting economic development efforts in that region. We expect electrification opportunities and manufacturing growth as a result of the shale buildout primarily in the Ohio, Pennsylvania and West Virginia areas, however, the increased production of natural gas in the Marcellus and Utica Shale region could continue to have a negative impact on natural gas prices.

Our regulated transmission segment is one of the largest owners of transmission assets in PJM with nearly 24,000 miles of high-voltage lines, including our ATSI and TrAIL standalone transmission operations. Our strategy remains focused on projects within our footprint that provide attractive investment returns through formula rates at our standalone subsidiaries, and projects that improve overall reliability within our region. A strong focus over the next few years will be improved reliability within ATSI, specifically in the Cleveland area, as well as a multi-year local infrastructure and transmission enhancement program for JCP&L.

Our competitive energy segment includes a diverse, low cost generation portfolio of approximately 18,000 MWs of competitive generation (including 885 MWs of capacity subject to RMR arrangements with PJM) which is deployed to a growing regional base of retail customers in competitive markets.

We are well-positioned for upcoming environmental regulations, including MATS, and expect to make capital investments over the next several years in certain of our unregulated and regulated generating plants of approximately $975 million to comply with MATS.

We expect to grow our competitive operations through several avenues over time, including modest growth in volumes/customers, shifting our customer mix with a focus on increased revenues/margins, and growing the generation capability of our existing fleet to match customer growth through incremental capital investments as market conditions justify. We recognize that the supply of natural gas has increased over the last several years due in part to the rise of shale gas production. As a result, wholesale electricity prices have decreased and the retail margins in our competitive operations have been compressed. We expect that the natural gas supply will continue to grow over the next few years. Since a portion of FirstEnergy's service territory is located within the Marcellus and Utica shale regions, we expect to benefit in the near term from the higher industrial demand needed to support the production of natural gas and general economic growth in this region. When power prices recover, FirstEnergy expects to benefit from our balanced portfolio of energy resources which includes low-emitting coal, nuclear, wind and solar. Also, factors such as state energy efficiency mandates and demand response initiatives have negatively impacted the demand for electricity and further depressed our retail sales margins. We expect the soft economy, weak demand for electricity, energy efficiency mandates, demand response initiatives and other regulations as well as increased costs related to more stringent environmental regulations to continue to impact our results of operations into 2013. We continue to believe FirstEnergy is one of the better positioned companies in our industry and region to benefit from increases in energy and capacity prices as economic conditions improve over time.

The following outlook sections contain forecasted data that could differ from actual results.

Financial Outlook

FirstEnergy endeavors to manage operating and capital costs in order to achieve our financial goals, including strengthening the balance sheet, improving liquidity and maintaining investment grade metrics for FirstEnergy and its operating subsidiaries.

In addition, FirstEnergy plans to strengthen the balance sheet of its competitive segment through a series of actions including asset transfers and the sale of non-strategic assets. In November 2012, FirstEnergy filed a proposal with the WVPSC for a net asset transfer of 1,476 MW, moving ownership of 1,576 MW at the Harrison plant from AE Supply to our regulated MP utility and transferring MP's ownership of 100 megawatts of the Pleasants plant to AE Supply in our competitive segment. In parallel, FirstEnergy is considering the sale of certain non-strategic assets, including its partial interest in a fleet of more than 1,180 MW of competitive hydro assets. Proceeds of these actions, if completed, are expected to be used to reduce debt at our competitive segment, targeted in the range of $1.5 billion, which would significantly improve the competitive segment's credit metrics.

Our liquidity position remains strong, with $172 million of cash and cash equivalents and over $3.3 billion of available liquidity as of January 31, 2013.

FirstEnergy plans to extend the $5.5 billion of existing credit facilities available by an additional year, through May 2018. FirstEnergy is also planning to incur additional long-term debt, which is expected to be used to reduce our short-term borrowings and is intended to lower future interest costs given today's favorable interest rate environment. FirstEnergy plans additional long-term debt of approximately $1 billion at the Utilities to refinance debt in the normal course. Subject to the completion of the West Virginia asset transfers, MP expects to incur additional long-term debt to repay short-term borrowings incurred to fund the transfer. FirstEnergy also expects the securitization of certain regulatory assets in Ohio to move forward, which will facilitate the planned debt reduction for our Ohio Companies. These actions are expected to preserve liquidity for our operating subsidiaries.

The following represents a high level summary of assumptions and drivers that management expects will impact 2013 results of operations and financial condition.

- Regulated Distribution segment sales of 148.5 million MWH in 2013 compared to 146.6 million MWH in 2012.
- Regulated Transmission segment revenue decrease of approximately $35 million compared to 2012, primarily due to lower TrAIL rate base and reduced NITS revenues which are based on peak load.
- Competitive Energy Services segment; competitive generation output of 93 million MWH in 2013 compared to 92 million MWH in 2012 based upon expectations that the dispatch of generating facilities will be based on market conditions for the year.
- Competitive Energy Services segment expects capacity revenue (RPM/Supplemental/Bilateral) reduction of $160 million compared to 2012 primarily as a result of RPM auction results.
- Targeted Competitive Energy Services sales by channel for 2013 include the following:

2013 Channel Sales	MWH (millions)	$ (millions)	$/MWH
Direct	58	$3,010	$52
Governmental Aggregation	22	1,250	56
Mass Market	6	390	65
Total Direct Retail Sales	86	4,650	54
POLR and Structured	18	900	50
Total Channel Sales	104	$5,550	$53

- Operation and maintenance expense reductions of $75 - 85 million compared to 2012; includes the impact of staffing reductions, benefit changes (including reductions to limit the life insurance benefits for active employees and retirees), overall corporate cost reductions and fewer fossil and nuclear outages in 2013.
- 2013 effective income tax rate assumption of 38% - 38.5%.

Capital Expenditures Outlook

Our capital expenditures in 2013 are estimated to be $2.4 billion (excluding nuclear fuel), a decrease of approximately $889 million from 2012, primarily due to restoration spending for major storms in our service territory in 2012. In addition to internal sources to fund capital requirements for 2013 and beyond, FirstEnergy expects to rely on external sources of funds, which may include access to the capital markets.

Baseline capital expenditures are forecast to decrease by $18 million in 2013 from $1.3 billion in 2012. The expected decrease primarily reflects lower baseline expenditures at our EDCs. Baseline capital expenditures are considered the level of annual ongoing maintenance-type capital, excluding major projects and capital that is recovered via formula rates.

Expenditures for formula rate and recovery projects are expected to decrease to $580 million in 2013 from $787 million in 2012. The decrease reflects lower expenditures by our Ohio distribution companies in 2013 partially offset by higher expenditures for transmission reliability improvements related to the deactivations of generating plants in northern Ohio.

Expenditures for major projects are expected to increase by $126 million in 2013 from $354 million in 2012. The main drivers of the increase are environmental spending related to MATS, reliability spending related to the JCP&L LITE program, the Davis-Besse steam generator replacement and the dry fuel storage projects at Beaver Valley and Perry.

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 billion at our Hatfield, Fort Martin and Sammis Plants further reduced emissions of SO_2 by over 95%, and NOx by at least 64% from these facilities. Since 1990, we have reduced emissions of NOx by more than 80%, SO_2 by more than 90%, and mercury by approximately 70%.

We have taken aggressive steps over the past two decades that have increased our generating capacity without adding to overall CO_2 emissions. In early 2012, we announced our intent to deactivate approximately 3,400 MW of older, coal-based generation. Approximately 2,500 MW were deactivated in September 2012, with 885 MW remaining available to meet electric system reliability concerns identified by the regional transmission operator. We expect FirstEnergy's CO_2 emissions to be approximately 20% below our 1990 levels, depending on economic conditions.

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 by more than 15 metric tons, resulting in an equivalent reduction of nearly 363,000 metric tons of CO_2 equivalent, as reported to the EPA's Mandatory Greenhouse Gas Reporting Rule.
- 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. On December 30, 2011, CSAPR was stayed by the U.S. Court of Appeals for the District of Columbia Circuit and was ultimately vacated by the Court on August 21, 2012. On January 24, 2013, EPA and intervenors' petitions seeking rehearing or rehearing en banc were denied by the U.S. Court of Appeals for the District of Columbia Circuit. The Court has ordered EPA to continue administration of CAIR until it finalizes a valid replacement for CAIR. The new MATS were finalized at the end of 2011, which contributed to our decision to deactivate some of our older coal-fired generation plants by September 1, 2012.

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. Results of operations for the year ended December 31, 2011, include only ten months of Allegheny results which have been segregated from the pre-merger companies (FirstEnergy and its subsidiaries prior to the merger) for reporting and analysis. In addition, Allegheny's results were affected by many of the same factors that influenced the operating results of the pre-merger companies. A reconciliation of segment financial results is provided in Note 18, Segment Information, of the Combined Notes to Consolidated Financial Statements. Earnings available to FirstEnergy by business segment were as follows:

				Increase (Decrease)	
	2012	2011	2010	2012 vs 2011	2011 vs 2010

	(in millions, except per share)				
Earnings (Loss) By Business Segment:					
Regulated Distribution	$540	$488	$522	$52	$(34)
Regulated Transmission	226	194	85	32	109
Competitive Energy Services	215	377	210	(162)	167
Other and reconciling adjustments [(1)]	(211)	(174)	(75)	(37)	(99)
Earnings available to FirstEnergy Corp.	$770	$885	$742	$(115)	$143
Basic Earnings Per Share	$1.85	$2.22	$2.44	$(0.37)	$(0.22)
Diluted Earnings Per Share	$1.84	$2.21	$2.42	$(0.37)	$(0.21)

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(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 — 2012 Compared with 2011

Financial results for FirstEnergy's business segments in 2012 and 2011 were as follows:

2012 Financial Results	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Other and Reconciling Adjustments	FirstEnergy Consolidated
	(In millions)				
Revenues:					
External					
Electric	$8,733	$ 740	$5,497	$—	$ 14,970
Other	164	—	311	(144)	331
Internal	—	—	866	(864)	2
Total Revenues	8,897	740	6,674	(1,008)	15,303
Operating Expenses:					
Fuel	263	—	2,208	—	2,471
Purchased power	3,801	—	1,298	(862)	4,237
Other operating expenses	1,963	132	1,849	(175)	3,769
Pension and OPEB mark-to-market	392	2	215	—	609
Provision for depreciation	558	118	414	34	1,124
Deferral of storm costs	(370)	(5)	—	—	(375)
Amortization of other regulatory assets, net	305	2	—	—	307
General taxes	706	44	210	25	985
Total Operating Expenses	7,618	293	6,194	(978)	13,127
Operating Income	1,279	447	480	(30)	2,176
Other Income (Expense):					
Investment income	84	1	66	(74)	77
Interest expense	(540)	(92)	(284)	(85)	(1,001)
Capitalized interest	12	3	44	13	72
Total Other Expense	(444)	(88)	(174)	(146)	(852)
Income Before Income Taxes	835	359	306	(176)	1,324
Income taxes	295	133	91	34	553
Net Income	540	226	215	(210)	771
Income attributable to noncontrolling interest	—	—	—	1	1
Earnings Available to FirstEnergy Corp.	$540	$ 226	$215	$(211)	$ 770

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2011 Financial Results	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Other and Reconciling Adjustments	FirstEnergy Consolidated
	(In millions)				
Revenues:					
External					
Electric	$9,544	$ 660	$5,462	$—	$ 15,666
Other	196	—	363	(145)	414
Internal	—	—	1,237	(1,170)	67
Total Revenues	9,740	660	7,062	(1,315)	16,147
Operating Expenses:					
Fuel	268	—	2,049	—	2,317
Purchased power	4,667	—	1,380	(1,172)	4,875
Other operating expenses	1,669	113	2,256	(74)	3,964
Pension and OPEB mark-to-market	290	2	215	—	507
Provision for depreciation	523	104	415	24	1,066
Deferral of storm costs	(145)	—	—	—	(145)
Amortization of other regulatory assets, net	468	6	—	—	474
General taxes	717	40	200	21	978
Impairment of long-lived assets	87	—	315	11	413
Total Operating Expenses	8,544	265	6,830	(1,190)	14,449
Operating Income	1,196	395	232	(125)	1,698
Other Income (Expense):					
Gain on partial sale of Signal Peak	—	—	569	—	569
Investment income	99	—	56	(41)	114
Interest expense	(530)	(89)	(298)	(91)	(1,008)
Capitalized interest	10	2	40	18	70
Total Other Income (Expense)	(421)	(87)	367	(114)	(255)
Income Before Income Taxes	775	308	599	(239)	1,443
Income taxes	287	114	222	(49)	574
Net Income	488	194	377	(190)	869
Loss attributable to noncontrolling interest	—	—	—	(16)	(16)
Earnings Available to FirstEnergy Corp.	$488	$ 194	$377	$(174)	$ 885

Changes Between 2012 and 2011 Financial Results Increase (Decrease)	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Other and Reconciling Adjustments	FirstEnergy Consolidated
	(In millions)				
Revenues:					
External					
Electric	$(811)	$ 80	$35	$—	$ (696)
Other	(32)	—	(52)	1	(83)
Internal	—	—	(371)	306	(65)
Total Revenues	(843)	80	(388)	307	(844)
Operating Expenses:					
Fuel	(5)	—	159	—	154
Purchased power	(866)	—	(82)	310	(638)
Other operating expenses	294	19	(407)	(101)	(195)
Pension and OPEB mark-to-market	102	—	—	—	102
Provision for depreciation	35	14	(1)	10	58
Deferral of storm costs	(225)	(5)	—	—	(230)
Amortization of other regulatory assets, net	(163)	(4)	—	—	(167)
General taxes	(11)	4	10	4	7
Impairment of long-lived assets	(87)	—	(315)	(11)	(413)
Total Operating Expenses	(926)	28	(636)	212	(1,322)
Operating Income	83	52	248	95	478
Other Income (Expense):					
Gain on partial sale of Signal Peak	—	—	(569)	—	(569)
Investment income	(15)	1	10	(33)	(37)
Interest expense	(10)	(3)	14	6	7
Capitalized interest	2	1	4	(5)	2
Total Other Expense	(23)	(1)	(541)	(32)	(597)
Income Before Income Taxes	60	51	(293)	63	(119)
Income taxes	8	19	(131)	83	(21)
Net Income	52	32	(162)	(20)	(98)
Income attributable to noncontrolling interest	—	—	—	17	17
Earnings Available to FirstEnergy Corp.	$52	$ 32	$(162)	$(37)	$ (115)

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Regulated Distribution — 2012 Compared to 2011

Net income increased by $52 million in 2012 compared to 2011, primarily due to two additional months of earnings from the Allegheny Utilities and lower merger-related costs, partially offset by decreased weather-related customer usage in 2012.

Results of operations for the year ended December 31, 2011, include only ten months of Allegheny results which have been segregated from the pre-merger companies (FirstEnergy and its subsidiaries prior to the merger) for reporting and analysis.

Revenues —

The $843 million decrease in total revenues resulted from the following sources:

Revenues by Type of Service	For the Years Ended December 31, 2012	2011	Increase (Decrease)
	(In millions)		
Pre-merger companies:			
Distribution services	$3,247	$3,428	$(181)
Generation sales:			
Retail	2,540	3,266	(726)
Wholesale	206	377	(171)
Total generation sales	2,746	3,643	(897)
Transmission	203	110	93
Other	167	180	(13)
Total pre-merger companies	6,363	7,361	(998)
Allegheny Utilities[1]	2,534	2,379	155
Total Revenues	$8,897	$9,740	$(843)

[1] Allegheny results include 12 months in 2012 and 10 months in 2011.

The decrease in distribution services revenue for the pre-merger companies reflects lower distribution deliveries (described below), the suspension of Ohio's deferred distribution cost recovery rider in December 2011 and an NJBPU-approved reduction to the JCP&L NUG Rider which became effective on March 1, 2012, partially offset by an increase in Ohio's energy efficiency rider and a PPUC-approved increase to the ME and PN NUG Riders which also became effective on March 1, 2012. Distribution deliveries (excluding the Allegheny Utilities) decreased by 1.7% in 2012 from 2011. Distribution deliveries by customer class are summarized in the following table:

Electric Distribution MWH Deliveries	For the Years Ended December 31, 2012	2011	Increase (Decrease)
	(In thousands)		
Pre-merger companies:			
Residential	38,493	39,369	(2.2)%
Commercial	32,149	32,610	(1.4)%
Industrial	35,139	35,637	(1.4)%
Other	492	513	(4.1)%
Total pre-merger companies	106,273	108,129	(1.7)%
Allegheny Utilities[1]	40,328	33,449	20.6%
Total Electric Distribution MWH Deliveries	146,601	141,578	3.5%

[1] Allegheny results include 12 months in 2012 and 10 months in 2011.

Lower deliveries to residential and commercial customers for the pre-merger companies primarily reflect decreased weather-related usage resulting from heating degree days that were 10% below 2011 levels, a slight reduction in the number of residential customers and declining average residential customer consumption caused, in part by, increasing energy efficiency mandates and demand response initiatives. In the industrial sector, MWH deliveries decreased 1.4%, reflecting slight decreases in deliveries to steel, petroleum and automotive customers.

The following table summarizes the price and volume factors contributing to the $897 million decrease in generation revenues for the pre-merger companies in 2012 compared to 2011:

Source of Change in Generation Revenues	Decrease (In millions)	
Retail:		
Effect of decrease in sales volumes	$(587	)
Change in prices	(139	)
	(726	)
Wholesale:		
Effect of decrease in sales volumes	(120	)
Change in prices	(51	)
	(171	)
Decrease in Generation Revenues	$(897	)

The decrease in retail generation sales volume was primarily due to increased customer shopping in the Utilities' service territories in 2012, compared with 2011. This increased customer shopping, which does not impact earnings for the Regulated Segment, is expected to continue. Total generation provided by alternative suppliers as a percentage of total MWH deliveries increased to 79% from 76% for the Ohio Companies, 64% from 52% for ME's, PN's and Penn's service areas and 50% from 44% for JCP&L. The decrease in retail generation prices resulted from the impact of lower auction prices on power supply prices in 2012 compared to 2011, partially offset by a full year of Ohio's RER Rider (recovers deferred costs relating to electric heating discounts).

The decrease in wholesale generation revenues of $171 million in 2012 resulted from the expiration and termination of NUG contracts in August 2011 and April 2012, lower capacity revenues and lower PJM market prices.

Transmission revenues increased $93 million primarily due to the implementation of Ohio's NMB transmission rider in June of 2011, which recovers network integration transmission service costs as described further below.

The Allegheny companies added $155 million to revenues in 2012, including $136 million for distribution services and $43 million from generation sales, partially offset by a decrease of $21 million of transmission revenues and $3 million of other revenues.

Operating Expenses —

Total operating expenses decreased by $926 million in 2012. Excluding the Allegheny Utilities, total operating expenses decreased by $885 million due to the following:

- Purchased power costs, excluding the Allegheny Utilities, were $890 million lower in 2012 due primarily to a decrease in volumes required from increased customer shopping, the impact of milder weather and lower unit power supply costs during 2012 compared to 2011 as a result of lower auction prices.

Source of Change in Purchased Power	Increase(Decrease) (In millions)	
Pre-merger companies:		
Purchases from non-affiliates:		
Change due to decreased unit costs	$ (149	)
Change due to decreased volumes	(490	)
	(639	)
Purchases from FES:		
Change due to decreased unit costs	(65	)
Change due to decreased volumes	(257	)
	(322	)
Decrease in costs deferred	71	
Total pre-merger companies	$ (890	)

- Transmission expenses increased $127 million during 2012 compared to 2011. The increase is primarily due to network integration transmission service expenses that, prior to June 2011, were incurred by the generation supplier, and are now being recovered through the NMB transmission rider referred to above.
- Other operation and maintenance expenses increased $197 million primarily due to higher labor, professional contractor and material costs to repair storm-related damage.
- Energy Efficiency program costs, which are recovered through rates, increased by $16 million.
- Other costs decreased due to the absence of a provision for excess and obsolete material of $13 million that was recognized in 2011 relating to revised inventory practices adopted in conjunction with the Allegheny merger.
- Merger-related costs decreased $60 million in 2012 compared to 2011.
- Pension and OPEB mark-to-market charges increased $87 million, reflecting lower discount rates to measure related obligations in 2012.
- Depreciation expense increased by $27 million due to a higher asset base.
- Deferral of storm costs increased by $186 million primarily related to storm restoration expenses associated with Hurricane Sandy and the "derecho" wind storm.
- Net regulatory asset amortization decreased $162 million primarily due to the scheduled suspension of the Ohio rider recovering deferred distribution costs in December 2011 and the rate reduction for JCP&L's NUG deferred cost recovery in March of 2012, partially offset by the recovery in Ohio of residential generation credits for electric heating discounts, which began in September 2011.
- General taxes decreased by $28 million primarily due to a decrease in revenue-related taxes.

Operating expenses for the Allegheny Utilities are summarized in the following table:

Operating Expenses - Allegheny[1]	For the Years Ended December 31, 2012	2011	Increase (Decrease)
	(In millions)		
Purchased Power	$1,170	$1,146	$24
Fuel	263	268	(5)
Transmission	114	120	(6)
Deferral of storm costs	(49)	(10)	(39)
Amortization of other regulatory assets, net	(14)	(13)	(1)
Pensions and OPEB mark-to-market adjustment	91	76	15
Other operating expenses	273	240	33
General taxes	130	113	17
Depreciation	152	144	8
Impairment of long-lived assets[2]	—	87	(87)
Total Operating Expenses	$2,130	$2,171	$(41)

(1) Allegheny results include 12 months in 2012 and 10 months in 2011.

(2) Deactivation of three regulated coal-fired fossil generating plants in West Virginia.

Other Expense —

Other expense increased $23 million in 2012 primarily due to higher interest expense on debt of the Allegheny Utilities and lower investment income on OE's and TE's NDT assets and the PNBV and Shippingport trusts.

Regulated Transmission — 2012 Compared with 2011

Net income increased by $32 million in 2012 compared to 2011 primarily due to two additional months of earnings in 2012 associated with TrAIL, PATH and the Allegheny Utilities' transmission assets that were acquired in the merger.

Revenues —

Total revenues increased by $80 million principally due to revenues from TrAIL, PATH and the Allegheny Utilities' transmission assets in 2012 compared to 2011.

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

Revenues by Transmission Asset Owner	For the Years Ended December 31, 2012	2011	Increase
	(In millions)		
ATSI	$213	$207	$6
TrAIL[(1)]	200	170	30
PATH[(1)]	18	14	4
Utilities[(1)]	309	269	40
Total Revenues	$740	$660	$80

(1) Allegheny results include 12 months in 2012 and 10 months in 2011.

Operating Expenses —

Total operating expenses increased by $28 million principally due to the addition of TrAIL, PATH and the Allegheny Utilities' transmission operating expenses for twelve months in 2012 compared to ten months in 2011, partially offset by reduced regulatory asset amortization due to the completion in May 2011 of ATSI's deferred vegetation management cost recovery.

Other Expense —

Other expense increased by $1 million due to twelve months of TrAIL interest expense in 2012 compared to ten months in 2011.

Competitive Energy Services — 2012 Compared with 2011

Net income decreased by $162 million in 2012, compared to 2011. The decrease 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 partially offset by 2011 impairment charges of $315 million primarily resulting from the decision to deactivate six older coal-fired generating plants. In addition, higher operating expenses were partially offset by increased direct and governmental aggregation sales and the inclusion of two additional months of earnings from the Allegheny companies in 2012. Results of operations for the year ended December 31, 2011, include only ten months of Allegheny results which have been segregated from the pre-merger companies (FirstEnergy and its subsidiaries prior to the merger) for reporting and analysis.

Revenues —

Total revenues decreased by $388 million in 2012, compared to 2011, primarily due to a decline in POLR and structured sales and the sale of RECs. Revenues were also adversely impacted by lower unit prices compared to 2011.These decreases were partially offset by growth in direct and governmental aggregation sales and the inclusion of the Allegheny companies for twelve months in 2012 compared to ten months in 2011.

The decrease in total revenues resulted from the following sources:

Revenues by Type of Service	For the Years Ended December 31, 2012	2011	Increase (Decrease)
	(In millions)		
Pre-merger Companies:			
Direct and Governmental Aggregation	$4,230	$3,785	$445
POLR and Structured	899	944	(45)
Wholesale	535	457	78
Transmission	120	108	12
RECs	7	67	(60)
Other	145	173	(28)
Allegheny companies[1]	1,615	1,639	(24)
Intra-segment eliminations[2]	(877)	(111)	(766)
Total Revenues	$6,674	$7,062	$(388)
Allegheny companies[1]			
Direct and Governmental Aggregation	$85	$84	$1
POLR and Structured	366	561	(195)
Wholesale	1,118	912	206
Transmission	45	88	(43)
Other	1	(6)	7
Total Revenues	$1,615	$1,639	$(24)

(1) Allegheny results include 12 months in 2012 and 10 months in 2011.

(2) Intra-segment eliminations represent the impact of wholesale netting transactions for FES and AE Supply on an hourly basis, and the elimination of intra-segment sales between the companies.

MWH Sales by Channel	For the Years Ended December 31, 2012	2011	Increase (Decrease)
	(In thousands)		
Pre-merger Companies:			
Direct	53,099	46,187	15.0%
Governmental Aggregation	22,499	17,722	27.0%
POLR and Structured	16,212	15,340	5.7%
Wholesale	96	2,916	(96.7)%
Intra-segment eliminations	(18,041)	(1,877)	—%
Allegheny companies[1]	29,900	26,609	12.4%
Total MWH Sales	103,765	106,897	(2.9)%
Allegheny companies[1]			
Direct and Governmental Aggregation	1,429	1,390	2.8%
POLR	5,874	7,974	(26.3)%
Structured	578	1,492	(61.3)%
Wholesale	22,019	15,753	39.8%
Total MWH Sales	29,900	26,609	12.4%

(1) Allegheny results include 12 months in 2012 and 10 months in 2011.

The increase in direct and governmental aggregation revenues of $445 million resulted from the acquisition of new residential, commercial and industrial customers. This segment's customer base increased to 2.6 million customers in

December 2012 as

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compared to 1.8 million in December 2011. The volume increase was partially offset by lower unit prices for commercial, industrial and governmental aggregation customers.
The decrease in POLR and structured revenues of $45 million was due primarily to lower sales volumes to the Ohio Companies, ME, PN and other non-associated companies. Revenues were also adversely impacted by lower unit prices, which were partially offset by increased structured sales. The decline in POLR sales reflects a continued strategic focus on other sales channels.
Wholesale revenues increased $78 million due to increased gains of $276 million on financially settled contracts, partially offset by $91 million decrease in short-term (net hourly positions) transactions resulting primarily from reduced generation and a $107 million decrease in capacity revenues.
The following tables summarize the price and volume factors contributing to changes in revenues (excluding the Allegheny companies):

Source of Change in Direct and Governmental Aggregation	Increase (Decrease) (In millions)
Direct and Governmental Aggregation:	
Effect of increase in sales volumes	$705
Change in prices	(260)
	$445

Source of Change in POLR and Structured Revenues	Increase (Decrease) (In millions)
POLR and Structured:	
Effect of increase in sales volumes	$16
Change in prices	(61)
	$(45)

Source of Change in Wholesale Revenues	Increase (Decrease) (In millions)
Wholesale:	
Effect of decrease in sales volumes	$(90)
Change in prices	(1)
Gain on settled contracts	276
Capacity revenue	(107)
	$78

The Allegheny companies had a decrease in POLR and structured revenues of $195 million due to lower sales volumes to associated companies. The decline in POLR sales reflects a continued focus on other sales channels by this segment. Transmission revenues declined $43 million due primarily to lower congestion revenues, partially offset by an increase in wholesale revenues due to the intra-segment sale to FES.

Operating Expenses —
Total operating expenses decreased $636 million in 2012. Excluding the Allegheny companies, total operating expenses decreased by $542 million in 2012 due to the following:

- Fuel costs increased $92 million primarily due to the absence of cash received in 2011 from the assignment of a substantially below-market, long-term fossil fuel contract to a third party ($123 million) and higher unit prices ($57 million), partially offset by lower volumes consumed ($88 million). Higher unit prices resulted primarily from a $50 million termination charge associated with the retirement of a coal contract that is no longer needed as a result of the plant deactivations. Volumes decreased as a result of the deactivation of fossil generating units, the temporary reduction in operations at the Sammis Plant in September 2012 and an increase in economic purchases of power.
- Purchased power costs decreased $36 million due to lower unit prices ($310 million) and reduced capacity expenses ($116 million), partially offset by higher volumes ($155 million) and losses on settled contract ($235 million). The increase

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in purchased power volumes primarily relates to the overall increase in direct and governmental aggregation sales volumes, economic purchases and lower generation resulting from the deactivation of fossil generating units and the temporary reduction in operations at Sammis.

- Fossil operating costs decreased by $44 million due primarily to lower contractor, materials and equipment costs resulting from a decrease in planned and unplanned generating unit outages.
- Nuclear operating costs decreased by $13 million due primarily to lower contractor, materials and equipment costs, which were partially offset by higher labor costs. In 2012, there were refueling outages at Davis Besse and Beaver Valley Units 1 and 2. There were refueling outages at Perry and Beaver Valley Unit 2 during 2011. Total MW days were reduced slightly in 2012 compared to 2011.
- Transmission expenses decreased $75 million due primarily to lower congestion, network and line loss costs, partially offset by higher ancillary costs.
- General taxes increased by $8 million primarily due to an increase in revenue-related taxes, which were partially offset by lower taxes associated with a lower ownership percentage in Signal Peak and lower property taxes.
- Depreciation expense decreased $14 million primarily due to a lower asset base resulting from 2011 asset sales and impairments, combined with credits resulting from a settlement with the DOE regarding storage of spent nuclear fuel.
- Other operating expenses decreased by $145 million primarily due to favorable mark-to-market adjustments on commodity contract positions ($123 million), a $5 million decrease in pensions and OPEB mark-to-market adjustment charges from lower net actuarial losses, and the absence of 2011 expenses for a $54 million excess and obsolete inventory adjustment relating to revised inventory practices adopted in connection with the Allegheny merger. These decreases were partially offset by net increases in other expenses of $37 million associated with the absence of revenue related to coal sales due to a lower ownership percentage in Signal Peak, and labor and agent fees associated with the retail business.
- Impairments of long-lived assets decreased $315 million compared to last year. The 2011 charges are due to the decision to deactivate of six unregulated, coal-fired generating plants.

The Allegheny companies' operations for twelve months in 2012 and ten months in 2011 added $1,494 million and $1,588 million to operating expenses, respectively, as shown in the following table:

Operating Expenses - Allegheny[(1)]	For the Years Ended December 31, 2012	2011	Increase (Decrease)
	(In millions)		
Fuel	$861	$794	$67
Purchased power	103	149	(46)
Fossil generation	154	152	2
Transmission	123	198	(75)
Other operating expenses	38	100	(62)
Pensions and OPEB mark-to-market adjustment	49	44	5
General taxes	42	40	2
Depreciation	124	111	13
Total Operating Expense	$1,494	$1,588	$(94)

(1) Allegheny results include 12 months in 2012 and 10 months in 2011.

Fuel expenses increased due to higher generation levels and fuel prices. The purchased power expense decreased due to lower volumes purchased and lower capacity expenses. Transmission expense declined as a result of lower congestion.

Other Expense —

Total other expense in 2012 increased $541 million compared to 2011 due to the absence of the gain on the partial sale of FEV's interest in Signal Peak in 2011 ($569 million), partially offset by reduced net interest expense ($18 million) from debt reductions in 2011 and higher investment income ($10 million) from the NDTs.

Other — 2012 Compared with 2011

Financial results from other operating segments and reconciling items, including interest expense on holding company debt and corporate support services revenues and expenses, resulted in a $37 million decrease in earnings available to FirstEnergy Corp. in 2012 compared to 2011. The decrease resulted primarily from lower other operating expenses ($94 million) due to lower merger-related costs. These benefits were offset by decreased investment income ($33 million), decreased income attributable to noncontrolling interest ($17 million) relating to Signal Peak, which was deconsolidated in the fourth quarter of 2011, and increased income tax expense ($83 million).

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	Regulated Transmission	Competitive Energy Services	Other and Reconciling Adjustments	FirstEnergy Consolidated
	(In millions)				
Revenues:					
External					
Electric	$9,544	$ 660	$5,462	$—	$ 15,666
Other	196	—	363	(145)	414
Internal	—	—	1,237	(1,170)	67
Total Revenues	9,740	660	7,062	(1,315)	16,147
Operating Expenses:					
Fuel	268	—	2,049	—	2,317
Purchased power	4,667	—	1,380	(1,172)	4,875
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Amortization of other regulatory assets, net	468	6	—	—	474
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Total Operating Expenses	8,544	265	6,830	(1,190)	14,449
Operating Income	1,196	395	232	(125)	1,698
Other Income (Expense):					
Gain on partial sale of Signal Peak	—	—	569	—	569
Investment income	99	—	56	(41)	114
Interest expense	(530)	(89)	(298)	(91)	(1,008)
Capitalized interest	10	2	40	18	70
Total Other Income (Expense)	(421)	(87)	367	(114)	(255)
Income Before Income Taxes	775	308	599	(239)	1,443
Income taxes	287	114	222	(49)	574
Net Income	488	194	377	(190)	869
Loss attributable to noncontrolling interest	—	—	—	(16)	(16)
Earnings Available to FirstEnergy Corp.	$488	$ 194	$377	$(174)	$ 885

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2010 Financial Results	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Other and Reconciling Adjustments	FirstEnergy Consolidated
	(In millions)				
Revenues:					
External					
Electric	$9,271	$ 398	$3,252	$—	$ 12,921
Other	151	—	323	(130)	344
Internal	139	—	2,301	(2,366)	74
Total Revenues	9,561	398	5,876	(2,496)	13,339
Operating Expenses:					
Fuel	—	—	1,432	—	1,432
Purchased power	5,273	—	1,724	(2,373)	4,624
Other operating expenses	1,321	91	1,393	(91)	2,714
Pensions and OPEB mark-to-market	82	(2)	107	3	190
Provision for depreciation	382	70	284	14	750
Deferral of storm costs	(14)	—	—	—	(14)
Amortization of other regulatory assets, net	726	10	—	—	736
General taxes	605	30	124	17	776
Impairment of long-lived assets	—	—	388	—	388
Total Operating Expenses	8,375	199	5,452	(2,430)	11,596
Operating Income	1,186	199	424	(66)	1,743
Other Income (Expense):					
Investment income	35	—	51	31	117
Interest expense	(395)	(66)	(232)	(152)	(845)
Capitalized interest	3	2	95	65	165
Total Other Expense	(357)	(64)	(86)	(56)	(563)
Income Before Income Taxes	829	135	338	(122)	1,180
Income taxes	307	50	128	(23)	462
Net Income	522	85	210	(99)	718
Loss attributable to noncontrolling interest	—	—	—	(24)	(24)
Earnings Available to FirstEnergy Corp.	$522	$ 85	$210	$(75)	$ 742

Changes Between 2011 and 2010 Financial Results Increase (Decrease)	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Other and Reconciling Adjustments	FirstEnergy Consolidated
	(In millions)				
Revenues:					
External					
Electric	$273	$ 262	$2,210	$—	$ 2,745
Other	45	—	40	(15)	70
Internal	(139)	—	(1,064)	1,196	(7)
Total Revenues	179	262	1,186	1,181	2,808
Operating Expenses:					
Fuel	268	—	617	—	885
Purchased power	(606)	—	(344)	1,201	251
Other operating expenses	348	22	863	17	1,250
Pensions and OPEB mark-to-market	208	4	108	(3)	317
Provision for depreciation	141	34	131	10	316
Deferral of storm costs	(131)	—	—	—	(131)
Amortization of other regulatory assets, net	(258)	(4)	—	—	(262)
General taxes	112	10	76	4	202
Impairment of long-lived assets	87	—	(73)	11	25
Total Operating Expenses	169	66	1,378	1,240	2,853
Operating Income	10	196	(192)	(59)	(45)
Other Income (Expense):					
Gain on partial sale of Signal Peak	—	—	569	—	569
Investment income	64	—	5	(72)	(3)
Interest expense	(135)	(23)	(66)	61	(163)
Capitalized interest	7	—	(55)	(47)	(95)
Total Other Expense	(64)	(23)	453	(58)	308
Income Before Income Taxes	(54)	173	261	(117)	263
Income taxes	(20)	64	94	(26)	112
Net Income	(34)	109	167	(91)	151
Income attributable to noncontrolling interest	—	—	—	8	8
Earnings Available to FirstEnergy Corp.	$(34)	$ 109	$167	$(99)	$ 143

Regulated Distribution — 2011 Compared with 2010

Net income decreased by $34 million in 2011 compared to 2010, primarily due to lower distribution revenues, higher pensions and OPEB mark-to-market charges and merger-related costs, partially offset by earnings from the Allegheny companies and the absence of a 2010 regulatory asset impairment associated with the Ohio companies' ESP. 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 Years Ended December 31, 2011	2010	Increase (Decrease)
	(In millions)		
Pre-merger companies:			
Distribution services	$3,428	$3,629	$(201)
Generation sales:			
Retail	3,266	4,457	(1,191)
Wholesale	377	702	(325)
Total generation sales	3,643	5,159	(1,516)
Transmission	110	454	(344)
Other	180	319	(139)
Total pre-merger companies	$7,361	$9,561	$(2,200)
Allegheny companies	2,379	—	2,379
Total Revenues	$9,740	$9,561	$179

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 for ME's and PN'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 Years Ended December 31, 2011	2010	Increase (Decrease)
	(in thousands)		
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 $1.5 billion 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 ME's, PN'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 ME and PN 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 of PJM.

The decrease in wholesale generation revenues reflected lower RPM revenues for ME and NP in the PJM market.

Transmission revenues decreased $344 million primarily due to the termination of ME’s and PN’s TSC rates effective January 1, 2011. This was partially offset by a new rider that became effective for the Ohio Companies in June 2011 that recovers network integration TSCs.

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

The Allegheny companies added $2,379 million to revenues in 2011, including $570 million for distribution services, $1,661 million from generation sales, $106 million of transmission revenues and $42 million of other revenues.

Operating Expenses —

Total operating expenses increased by $169 million in 2011. Excluding the Allegheny companies, total operating expenses decreased $2.0 billion due to the following:

- Purchased power costs were $1.8 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 ME’s and PN’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 ME’s and PN’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 decreased volumes	515
	(311)
Purchases from FES:	
Change due to increased unit costs	165
Change due to decreased volumes	(1,606)
	(1,441)
Total pre-merger companies	(1,752)
Purchases by Allegheny companies	1,146
Net Decrease in Purchased Power Costs	$(606)

- Other operating expenses decreased $11 million, primarily due to the following:

Operation and maintenance expenses increased $162 million due primarily to higher storm restoration expenses associated with Hurricane Irene and an October 2011 East Coast snowstorm, primarily impacting the JCP&L and ME service territories. Approximately 95% of the total costs were deferred for future recovery from customers.

Energy efficiency and state reimbursed program costs, which are also recovered through rates, increased by $106 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 ME and PN in 2011.

- Pensions and OPEB mark-to-market adjustment charges increased $132 million as a result of higher net actuarial losses.
- Deferral of storm costs increased by $121 million primarily related to Hurricane Irene and the East Coast snowstorm.
- Net amortization of other regulatory assets decreased $245 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, partially offset by increased energy efficiency cost recovery.

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
Deferral of storm costs	(10)
Amortization of other regulatory assets, net	(13)
Pensions and OPEB mark-to-market adjustment	76
Other operating expenses	240
General taxes	113
Depreciation expense	144
Impairment of long lived asset[1]	87
Total Operating Expenses	$2,171

[1] Deactivation of three coal-fired fossil generating plants in West Virginia.

Other Expense —

Other expense increased $64 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 NDTs and increased capitalized interest.

Regulated Transmission — 2011 Compared with 2010

Net income increased by $109 million in 2011 compared to 2010 due to earnings associated with TrAIL, PATH and the Allegheny Utilities, partially offset by decreased earnings for ATSI.

Revenues —

Total revenues increased by $262 million primarily due to revenues from TrAIL and PATH and the Allegheny Utilities, 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	Years Ended December 31 2011	2010	Increase (Decrease)
	(In millions)		
ATSI	$207	$242	$(35)
TrAIL	170	—	170
PATH	14	—	14
Utilities	269	156	113
Total Revenues	$660	$398	$262

Operating Expenses —

Total operating expenses increased by $66 million primarily due to the addition of TrAIL and PATH and the Allegheny Utilities in 2011.

Other Expense —

Other expense increased $23 million in 2011 due to additional interest expense associated with TrAIL.

Competitive Energy Services — 2011 Compared to 2010

Net income increased by $167 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 by $1.2 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)		
Pre-merger Companies			
Direct and Governmental Aggregation	$3,785	$2,493	$1,292
POLR and Structured	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
Intra-segment eliminations[1]	(111)	—	(111)
Total Revenues	$7,062	$5,876	$1,186
Allegheny Companies			
Direct and Governmental Aggregation	$84		
POLR and Structured	561		
Wholesale	912		
Transmission	88		
Other	(6)		
Total Revenues	$1,639		

[1] Intra-segment eliminations represent the impact of wholesale netting transactions for FES and AE Supply on an hourly basis.

MWH Sales by Channel	2011	2010	Increase (Decrease)
	(In thousands)		
Direct	46,187	28,499	17,688
Governmental Aggregation	17,722	12,796	4,926
POLR and Structured	15,340	50,358	(35,018)
Wholesale	2,916	5,391	(2,475)
Allegheny companies	26,609	—	26,609
Intra-segment eliminations	(1,877)	—	(1,877)
Total MWH Sales	106,897	97,044	9,853
Allegheny Companies			
Direct and Governmental Aggregation	1,390		
POLR	7,974		
Structured	1,492		
Wholesale	15,753		
Total Sales	26,609		

The increase in direct and governmental aggregation revenues of $1.3 billion, excluding the Allegheny companies, 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 revenues of $1.6 billion was due to lower sales volumes to ME, PN 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 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:

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 Increases in Direct and Governmental 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	$(51)
Change in prices	14
Loss on settled contracts	(29)
Capacity revenue	126
	$60

Operating Expenses —

Total operating expenses increased by $1.4 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 $493 million as lower volumes ($760 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 ME and PN.
- Fossil operating costs increased $36 million due primarily to higher labor, contractor and material costs resulting from an increase in planned and unplanned generating unit 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 environmental 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 $73 million compared to last year. The 2011 charges are due to the decision to deactivate six unregulated, coal-fired generating plants; 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 NDT 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 a $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), an asset impairment charge in the first quarter of 2011 ($11 million) and higher income taxes ($26 million).

Regulatory Assets

Regulatory assets represent incurred costs that have been deferred because of their probable future recovery from customers through regulated rates. Regulatory liabilities represent amounts that are expected to be credited to customers through future regulated rates or amounts collected from customers for costs not yet incurred. FirstEnergy and the Utilities net their regulatory assets and liabilities based on federal and state jurisdictions. The following table provides information about the composition of net regulatory assets as of December 31, 2012 and December 31, 2011, and the changes during the year ended December 31, 2012:

Regulatory Assets by Source	December 31, 2012	December 31, 2011	Increase (Decrease)
	(In millions)		
Regulatory transition costs	$281	$309	$(28)
Customer receivables for future income taxes	508	519	(11)
Nuclear decommissioning and spent fuel disposal costs	(219)	(210)	(9)
Asset removal costs	(372)	(347)	(25)
Deferred transmission costs	390	340	50
Deferred generation costs	379	400	(21)
Deferred distribution costs	231	267	(36)
Contract valuations	463	299	164
Storm-related costs	509	144	365
Other	205	309	(104)
Total	$2,375	$2,030	$345

Regulatory assets that do not earn a current return totaled approximately $779 million as of December 31, 2012. JCP&L had $386 million of regulatory assets not earning a current return, which include storm damage costs. The remaining $393 million of regulatory assets include PJM transmission and regulatory transition costs that are expected to be recovered by 2020.

As of December 31, 2012 and December 31, 2011, FirstEnergy had approximately $392 million and $381 million, respectively, of net regulatory liabilities that are primarily related to asset removal costs. Net regulatory liabilities are classified within Other Noncurrent Liabilities on the Consolidated Balance Sheets.

CAPITAL RESOURCES AND LIQUIDITY

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 2013 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 the issuance of long-term debt and/or equity. 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 plans to extend the $5.5 billion of existing credit facilities available by an additional year, through May 2018. FirstEnergy is also planning to incur additional long-term debt, which is expected to be used to reduce our short-term borrowings and is intended to lower future interest costs given today's favorable interest rate environment. FirstEnergy plans additional long-term debt of approximately $1 billion at the Utilities to refinance debt in the normal course. Subject to the completion of the West Virginia asset transfers, MP expects to incur additional long-term debt to repay short-term borrowings incurred to fund the transfer. FirstEnergy also expects the securitization of certain regulatory assets in Ohio to move forward, which will facilitate the planned debt reduction for our Ohio Companies.

These actions are expected to preserve liquidity for our operating subsidiaries.

In addition, FirstEnergy plans to strengthen the balance sheet of its competitive segment through a series of actions including asset transfers and the sale of non-strategic assets. In November 2012, FirstEnergy filed a proposal with the WVPSC for a net asset transfer of 1,476 MW, moving ownership of 1,576 MW at the Harrison plant from AE Supply to our regulated MP utility and transferring MP's ownership of 100 megawatts of the Pleasants plant to AE Supply in our competitive segment. In parallel, FirstEnergy is considering the sale of certain non-strategic assets, including its partial interest in a fleet of more than 1,180 MW of competitive hydro assets. Proceeds of these actions, if completed, are expected to be used to reduce debt at our competitive segment, targeted in the range of $1.5 billion, which would significantly improve the competitive segment's credit metrics.

A material adverse change in operations, or in the availability of external financing sources, could impact FirstEnergy's liquidity position and ability to fund its capital requirements. To mitigate risk, FirstEnergy's business strategy stresses financial discipline and a strong focus on execution. Major elements include the expectation of: adequate cash from operations, opportunities for favorable long-term earnings growth in the competitive generation markets, operational excellence, business plan execution, well-positioned generation fleet, no speculative trading operations, appropriate long-term commodity hedging positions, manageable capital expenditure program, adequately funded pension plan, minimal near-term maturities of existing long-term debt and a commitment to a secure dividend.
As of December 31, 2012, FirstEnergy's net deficit in working capital (current assets less current liabilities) was due in large part to currently payable long-term debt and short-term borrowings. Currently payable long-term debt as of December 31, 2012, included the following:

Currently Payable Long-term Debt	(In millions)
PCRBs supported by bank LOCs [1]	$809
Unsecured notes	750
Unsecured PCRBs [1]	235
Collateralized lease obligation bonds	126
Sinking fund requirements	55
Other notes	24
	$1,999

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

Short-Term Borrowings

FirstEnergy had $1,969 million of short-term borrowings as of December 31, 2012, and no significant short-term borrowings as of December 31, 2011. FirstEnergy's available liquidity as of January 31, 2013, was as follows:

Borrower(s)	Type	Maturity	Commitment (In millions)	Available Liquidity
FirstEnergy[1]	Revolving	May 2017	$2,000	$776
FES / AE Supply	Revolving	May 2017	2,500	2,488
FET[2]	Revolving	May 2017	1,000	—
AGC	Revolving	Dec. 2013	50	15
		Subtotal	$5,550	$3,279
		Cash	—	61
		Total	$5,550	$3,340

(1) FE and the Utilities.

(2) Includes FET, ATSI and TrAIL.

Revolving Credit Facilities

FirstEnergy, FES/AE Supply and FET Facilities

FE and certain of its subsidiaries participate in three five-year syndicated revolving credit facilities with aggregate commitments of $5.5 billion (Facilities). The Facilities consist of a $2.0 billion aggregate FirstEnergy Facility, a $2.5 billion FES/AE Supply Facility and a $1.0 billion FET Facility, that are each available until May 2017, 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. Each of the Facilities contains financial covenants requiring each borrower to maintain a consolidated debt to total capitalization ratio of no more than 65%, and 70% for FET, measured at the end of each fiscal quarter.

The following table summarizes the borrowing sub-limits for each borrower under the Facilities, the limitations on short-term indebtedness applicable to each borrower under current regulatory approvals and applicable statutory and/or charter limitations, as well as the debt to total capitalization ratios (as defined under each of the Facilities) as of December 31, 2012:

Borrower	FirstEnergy Revolving Credit Facility Sub-Limit (In millions)	FES/AE Supply Revolving Credit Facility Sub-Limit	FET Revolving Credit Facility Sub-Limit	Regulatory and Other Short-Term Debt Limitations		Debt to Capitalization
FE	$2,000	$—	$—	$—	(1)	60.2%
FES	—	1,500	—	—	(2)	53.4%
AE Supply	—	1,000	—	—	(2)	32.0%
FET	—	—	1,000	—	(1)	65.2%
OE	500	—	—	500	(3)	63.4%
CEI	500	—	—	500	(3)	63.5%
TE	500	—	—	500	(3)	63.4%
JCP&L	425	—	—	850	(3)	47.5%
ME	300	—	—	500	(3)	55.5%
PN	300	—	—	300	(3)	57.1%
WP	200	—	—	200	(3)	50.0%
MP	150	—	—	150	(3)	55.0%
PE	150	—	—	150	(3)	54.8%
ATSI	—	—	100	100	(3)	48.9%
Penn	50	—	—	50	(3)	41.1%
TrAIL	—	—	200	400	(3)	44.1%

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

As of December 31, 2012, FE and its subsidiaries could issue additional debt of approximately $4.3 billion, or recognize a reduction in equity of approximately $2.3 billion, and remain within the limitations of the financial covenants required by the Facilities.

The entire amount of the FES/AE Supply Facility, $700 million of the FirstEnergy Facility and $225 million of the FET Facility, subject to each borrower's sub-limit, is available for the issuance of LOCs expiring up to one year from the date of issuance. The stated amount of outstanding LOCs will count against total commitments available under each of the Facilities and against the applicable borrower's borrowing sub-limit.

The Facilities do not contain provisions that restrict the ability to borrow or accelerate payment of outstanding advances in the event of any change in credit ratings of the borrowers. Pricing is defined in "pricing grids," whereby the cost of funds borrowed under the Facilities is related to the credit ratings of the company borrowing the funds, other than the FET Facility, which is based on its subsidiaries' credit ratings. Additionally, 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.

AGC Revolving Credit Facility

A separate $50 million revolving credit facility is available to AGC until December 2013. Under the terms of this credit facility, outstanding debt of AGC may not exceed 65% of the sum of its debt and equity as of the last day of each calendar quarter. This provision limits the debt level of AGC and also limits the net assets of AGC that may be transferred to AE. As of December 31, 2012, the debt to total capitalization ratio for AGC (as defined under this credit facility) was 51% and AGC could issue additional debt of approximately $41 million and remain within the limitations of the financial covenants under this credit facility.

FirstEnergy Money Pools

FirstEnergy's regulated companies also have the ability to borrow from each other and the holding company to meet their short-term working capital requirements. A similar but separate arrangement exists among FirstEnergy's unregulated companies. FESC administers these two money pools and tracks surplus funds of FirstEnergy and the respective regulated and unregulated subsidiaries, as well as proceeds available from bank borrowings. Companies receiving a loan under the money pool agreements must repay the principal amount of the loan, together with accrued interest, within 364 days of borrowing the funds. The rate of interest is the same for each company receiving a loan from their respective pool and is based on the average cost of funds available through the pool. The average interest rate for borrowings in 2012 was 0.58% per annum for the regulated companies' money pool and 1.28% per annum for the unregulated companies' money pool.

Pollution Control Revenue Bonds

As of December 31, 2012, FirstEnergy's currently payable long-term debt included approximately $809 million ($736 million applicable to FES) of variable interest rate PCRBs, the bondholders of which are entitled to the benefit of irrevocable direct pay bank LOCs. The interest rates on the PCRBs are reset daily or weekly. Bondholders can tender their PCRBs for mandatory purchase prior to maturity with the purchase price payable from remarketing proceeds or, if the PCRBs are not successfully remarketed, by drawings on the irrevocable direct pay LOCs. The subsidiary obligor is required to reimburse the applicable LOC bank for any such drawings or, if the LOC bank fails to honor its LOC for any reason, must itself pay the purchase price.

The LOCs for FirstEnergy's variable interest rate PCRBs outstanding as of December 31, 2012 were issued by the following banks:

LOC Bank	Aggregate LOC Amount[(1)] (In millions)	LOC Termination Date	Reimbursements of LOC Draws Due
UBS	$268	April 2014	April 2014
CitiBank N.A.	164	June 2014	June 2014
Wells Fargo	151	March 2014	March 2014
The Bank of Nova Scotia	49	April 2014	Multiple dates[(2)]
The Bank of Nova Scotia	81	April 2015	April 2015
The Bank of Nova Scotia	96	December 2015	December 2015
Total	$809		

(1) Excludes approximately $9 million of applicable interest coverage.

(2) Earlier of 6 months from drawing or the LOC termination date.

Long-Term Debt Capacity

As of December 31, 2012, the Ohio Companies and Penn had the aggregate capacity to issue approximately $2.5 billion of additional FMBs on the basis of property additions and retired bonds under the terms of their respective FMB 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 to incur additional secured debt not otherwise permitted by a specified exception of up to $161 million. As a result of the indenture provisions, CEI and TE cannot incur any additional secured debt. ME and PN had the capability to issue secured debt of approximately $395 million and $404 million, respectively, under provisions of their senior note indentures as of December 31, 2012. In addition, based upon their net earnings and available bondable property additions as of December 31, 2012, MP, PE and WP had the capacity to issue approximately $1.5 billion of additional FMBs in the aggregate under the terms of their FMB indentures. The issuance of FMBs by these companies is subject to compliance with the financial covenants of the Facilities and any required regulatory approvals and may be subject to statutory and/or charter limitations.

Based upon FG's and NG's net earnings and available bondable property additions under their FMB indentures as of December 31, 2012, FG and NG had the capacity to issue $2.0 billion and $2.4 billion, respectively, of additional FMBs under the terms of their indentures.

On October 10, 2012, the PUCO approved the application of CEI, OE and TE for a financing order to securitize previously incurred costs that are currently being recovered from customers under certain PUCO-approved deferred recovery riders, with an estimated December 31, 2012 aggregate balance of approximately $436 million as set forth in the application. When the transactions are executed, the proceeds are expected to be used to assist the Ohio Companies in their planned debt reductions. On November 9, 2012, an application for rehearing was filed for the Ohio securitization transaction. The PUCO amended the financing order in part on December 19, 2012 by its Entry on

Rehearing. On January 9, 2013, the PUCO issued an Entry Nunc Pro Tunc to correct certain errors contained in the Entry on Rehearing issued in December. The financing order became final on February 18, 2013.

FE's and its subsidiaries' access to capital markets and costs of financing are influenced by the credit ratings of their securities. The following table displays FE’s and its subsidiaries’ credit ratings as of February 22, 2013:

	Senior Secured			Senior Unsecured		
Issuer	S&P	Moody’s	Fitch	S&P	Moody’s	Fitch
FE	—	—	—	BB+	Baa3	BBB-
FES	—	—	—	BBB-	Baa3	BBB-
AE Supply	—	—	—	BBB-	Baa3	BBB-
AGC	—	—	—	BBB-	Baa3	BBB
ATSI	—	—	—	BBB-	Baa1	BBB+
CEI	BBB	Baa1	BBB	BBB-	Baa3	BBB-
JCP&L	—	—	—	BBB-	Baa2	BBB+
ME	BBB	A3	A-	BBB-	Baa2	BBB+
MP	BBB+	Baa1	A-	BBB-	Baa3	BBB+
OE	BBB	A3	BBB+	BBB-	Baa2	BBB
PN	BBB	A3	BBB+	BBB-	Baa2	BBB
Penn	BBB+	A3	BBB+	—	—	—
PE	BBB+	Baa1	A-	BBB-	Baa3	BBB+
TE	BBB	Baa1	BBB	—	—	—
TrAIL	—	—	—	BBB-	A3	BBB+
WP	BBB+	A3	A-	BBB-	Baa2	BBB+

On February 22, 2013, Fitch Ratings changed the rating of FE and FES to BBB-, ATSI and TrAIL to BBB+, and changed the outlook for JCP&L to negative.

Changes in Cash Position

As of December 31, 2012, FirstEnergy had $172 million of cash and cash equivalents compared to $202 million of cash and cash equivalents as of December 31, 2011. As of December 31, 2012 and December 31, 2011, FirstEnergy had approximately $62 million and $79 million, respectively, of restricted cash included in Other Current Assets on the Consolidated Balance Sheets.

During 2012, FirstEnergy received $900 million of cash dividends and capital returned from its subsidiaries and paid $920 million in cash dividends to common shareholders.

Cash Flows From Operating Activities

FirstEnergy’s consolidated net cash from operating activities was provided by its regulated distribution, regulated transmission and competitive energy services businesses (see Results of Operations above). Net cash provided from operating activities was $2,320 million during 2012, $3,063 million during 2011 and $3,076 million during 2010, as summarized in the following table:

	For the Years Ended December 31,		
Operating Cash Flows	2012	2011	2010
	(In millions)		
Net income	$771	$869	$718
Non-cash charges	2,063	2,310	2,305
Pension trust contributions	(600)	(372)	—
Working capital and other	86	256	53
	$2,320	$3,063	$3,076

The $247 million decrease in non-cash charges in 2012 is primarily due to the following:

- $58 million from increased depreciation due to a higher asset base during 2012 compared to 2011.
- $230 million from higher storm cost deferrals primarily related to Hurricane Sandy and the "derecho" wind storm.
-

$167 million from lower net amortization of other regulatory assets as a result of the suspension of the rider recovering deferred distribution costs in September 2011 and the completion of JCP&L's NUG deferred cost recovery, partially offset by the recovery in Ohio of residential generation credits for electric heating discounts, which began in September 2011.

- $413 million from decreased impairments of long-lived assets during 2012 compared to 2011, primarily due to the decision to deactivate certain coal-fired plants.
- $528 million from decreased gain on assets sales during 2012 compared to 2011, mostly due to the sale of a portion of FirstEnergy's interest in Signal Peak in 2011.

The $170 million decrease in cash flows from working capital and other is primarily due to the following:

- $160 million from lower collections from customers during 2012 primarily as a result of the effects of milder weather described in Results of Operations above.
- $148 million of increased asset removal costs charged to income primarily related to hurricane Sandy.
- $64 million from materials and supplies, primarily due to the absence in 2012 of the non-cash inventory valuation adjustment recorded in connection with the merger.
- $36 million from higher accounts payable balances at the end of 2012, primarily due to hurricane Sandy.
- $124 million from accrued compensation and retirement benefits as a result of higher performance-related incentive compensation paid during 2012 compared to 2011.

Cash Flows From Financing Activities

In 2012, cash provided from financing activities was $807 million compared to $2,924 million of net cash used for financing activities during 2011. The following tables summarize new debt financing (net of any discounts) and redemptions:

	For the Years Ended December 31,		
Securities Issued or Redeemed / Retired	2012	2011	2010
	(In millions)		
New Issues			
PCRBs	$650	$272	$740
Long-term revolving credit	—	70	—
Senior secured notes	—	—	350
FMBs	100	—	—
Unsecured Notes	—	262	9
	$750	$604	$1,099
Redemptions / Retirements			
PCRBs	$238	$792	$741
Long-term revolving credit	—	495	—
Senior secured notes	118	460	141
FMBs	—	15	32
Unsecured notes	584	147	101
	$940	$1,909	$1,015
Short-term borrowings, net	$1,969	$(700)	$(378)

During 2012, FES remarketed or refinanced approximately $682 million of PCRBs. Of this amount, approximately $411 million related to PCRBs that were retired by the company in 2011.

On April 16, 2012, WP issued $100 million of FMBs through a private placement at a rate of 3.34%. These bonds have a maturity date of April 15, 2022, and the proceeds were used in part to retire $80 million of 6.625% medium term notes that matured on April 16, 2012.

On April 16, 2012, AE Supply retired $503.2 million of 8.25% medium term notes at maturity.

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Cash Flows From Investing Activities

Cash used for investing activities in 2012 principally represented cash used for property additions. The following table summarizes investing activities for 2012, 2011 and 2010:

Cash Used for (Provided from) Investing Activities	For the Years Ended December 31, 2012	2011	2010
	(In millions)		
Property Additions:			
Regulated distribution	$1,074	$868	$490
Regulated transmission	507	390	255
Competitive energy services	1,014	778	976
Other and reconciling adjustments	83	93	59
Nuclear fuel	286	149	183
Cash received in Allegheny merger	—	(590)	—
Investments	(79)	(798)	(136)
Asset removal costs	229	114	35
Other	43	(48)	86
	$3,157	$956	$1,948

Net cash used for investing activities during 2012 increased by $2,201 million compared to 2011. The increase was principally due to the absence in 2012 of cash acquired in the Allegheny merger ($590 million), an increase in property additions primarily due to increased storm costs ($549 million) and nuclear fuel costs ($137 million) and a decrease in proceeds from asset sales ($823 million) primarily related to the sale of the Fremont Energy Center and a portion of FirstEnergy's interest in Signal Peak in 2011, partially offset by a decrease in net purchases of investment securities ($62 million) and additional cash investments ($42 million).

Our capital spending for 2013 is expected to be approximately $2.4 billion (excluding nuclear fuel). 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 $205 million in 2013.

CONTRACTUAL OBLIGATIONS

As of December 31, 2012, our estimated cash payments under existing contractual obligations that we consider firm obligations are as follows:

Contractual Obligations	Total	2013	2014-2015	2016-2017	Thereafter
	(In millions)				
Long-term debt(1)	$16,854	$1,970	$2,665	$3,003	$9,216
Short-term borrowings	1,969	1,969	—	—	—
Interest on long-term debt(2)	11,176	946	1,688	1,464	7,078
Operating leases(3)	2,620	210	408	324	1,678
Fuel and purchased power(4)	25,062	2,724	4,197	3,635	14,506
Capital expenditures	2,124	588	957	360	219
Pension funding	2,103	—	240	995	868
Other(5)	262	41	110	56	55
Total	$62,170	$8,448	$10,265	$9,837	$33,620

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

(2) Interest on variable-rate debt based on rates as of December 31, 2012.
(3) See Note 5, Leases, of the Combined Notes to Consolidated Financial Statements.
(4) Amounts under contract with fixed or minimum quantities based on estimated annual requirements.

(5) Includes amounts for capital leases (see Note 5, Leases, of the Combined Notes to Consolidated Financial Statements) and contingent tax liabilities (see Note 4, Taxes, of the Combined Notes to Consolidated Financial Statements).

Excluded from the data shown above are estimates for the cash outlays from power purchase contracts entered into by most of the Utilities and under which they procure the power supply necessary to provide generation service to their customers who do not choose an alternative supplier. Although actual amounts will be determined by future customer behavior and consumption levels, management currently estimates these cash outlays will be approximately $2.9 billion in 2013, $0.6 billion of which are expected to relate to the Utilities' contracts with FES.

GUARANTEES AND OTHER ASSURANCES

FirstEnergy has various financial and performance guarantees and indemnifications which are issued in the normal course of business. These contracts include performance guarantees, stand-by letters of credit, debt guarantees, surety bonds and indemnifications. FirstEnergy enters into these arrangements to facilitate commercial transactions with third parties by enhancing the value of the transaction to the third party. The maximum potential amount of future payments FirstEnergy could have been required to make under these guarantees as of December 31, 2012, was approximately $4.0 billion, as summarized below:

Guarantees and Other Assurances	Maximum Exposure (In millions)
FirstEnergy Guarantees on Behalf of its Subsidiaries	
Energy and Energy-Related Contracts(1)	$291
LOC (long-term debt) - interest coverage(2)	5
OVEC obligations	300
Other(3)	299
	895
Subsidiaries’ Guarantees	
Energy and Energy-Related Contracts	137
LOC (long-term debt) - interest coverage(2)	3
FES’ guarantee of NG’s nuclear property insurance	85
FES’ guarantee of FG’s sale and leaseback obligations	2,161
Other	11
	2,397
Global Holding facility	350
Surety Bonds	239
LOCs(4)	164
	753
Total Guarantees and Other Assurances	$4,045

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

(2) Reflects the interest coverage portion of LOCs issued in support of floating rate PCRBs with various maturities. The principal amount of floating-rate PCRBs of $809 million is reflected in currently payable long-term debt on FirstEnergy's consolidated balance sheets.

(3) Includes guarantees of $106 million for nuclear decommissioning funding assurances, $161 million supporting OE’s sale and leaseback arrangements, and $25 million for railcar leases.

(4) Includes $31 million issued for various terms pursuant to LOC capacity available under FirstEnergy’s revolving credit facilities, $102 million pledged in connection with the sale and leaseback of Beaver Valley Unit 2 by OE and $31 million pledged in connection with the sale and leaseback of Perry by OE.

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

Collateral and Contingent-Related Features

As part of the normal course of business, FirstEnergy and its subsidiaries routinely enter into physical or financially settled contracts for the sale and purchase of electric capacity, energy, fuel, and emission allowances. Certain bilateral agreements and derivative instruments contain provisions that require FirstEnergy or its subsidiaries to post collateral. This collateral may be posted in the form of cash or credit support with thresholds contingent upon FirstEnergy's or its subsidiaries' credit rating from each of the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty. The incremental collateral requirement allows for the offsetting of assets and liabilities with the same counterparty, where the contractual right of offset exists under applicable master netting agreements.

Bilateral agreements and derivative instruments entered into by FirstEnergy and its subsidiaries have margining provisions that require posting of collateral. Based on FES' power portfolio exposure as of December 31, 2012, FES has posted collateral of $77 million. The Regulated Distribution segment has posted collateral of $9 million.

These credit-risk-related contingent features stipulate that if the subsidiary were to be downgraded or lose its investment grade credit rating (based on its senior unsecured debt rating), it would be required to provide additional collateral. Depending on the volume of forward contracts and future price movements, higher amounts for margining could be required.

Subsequent to the occurrence of a senior unsecured credit rating downgrade to below S&P's BBB- and Moody's Baa3 and lower, or a “material adverse event,” the immediate posting of collateral or accelerated payments may be required of FirstEnergy or its subsidiaries. The following table discloses the additional credit contingent contractual obligations as of December 31, 2012:

Collateral Provisions	FES	AE Supply	Utilities	Total
	(In millions)			
Split Rating (One rating agency's rating below investment grade)	$372	$6	$35	$413
BB+/Ba1 Credit Ratings	$427	$6	$55	$488
Full impact of credit contingent contractual obligations	$628	$55	$90	$773

Excluded above are potential collateral obligations due to affiliate transactions between the Regulated Distribution Segment and Competitive Energy Segment. As of December 31, 2012, neither FES nor AE Supply had any collateral posted with their affiliates. In the event of a senior unsecured credit rating downgrade to below S&P's BB- or Moody's Ba3, FES and AE Supply would be required to post $39 million and $9 million, respectively.

Other Commitments and Contingencies

FirstEnergy is a guarantor under a syndicated three-year senior secured term loan facility due October 18, 2015, under which Global Holding borrowed $350 million. Proceeds from the loan were used to repay Signal Peak's and Global Rail's maturing $350 million syndicated two-year senior secured term loan facility. In addition to FirstEnergy each of, Signal Peak, Global Rail, Global Mining Group, LLC and Global Coal Sales Group, LLC, each being a direct or indirect subsidiary of Global Holding, have also provided their joint and several guaranties of the obligations of Global Holding under the new facility.

In connection with the new facility, 69.99% of Global Holding's direct and indirect membership interests in Signal Peak, Global Rail and their affiliates along with FEV's and WMB Marketing Ventures, LLC's respective 33-1/3% membership interests in Global Holding, are pledged to the lenders under the new facility as collateral.

FirstEnergy, FEV and the other two co-owners of Global Holding, Pinesdale LLC, a Gunvor Group, Ltd. subsidiary, and WMB Marketing Ventures, LLC, have agreed to use their best efforts to refinance the new facility by December 31, 2013 on a non-recourse basis so that FirstEnergy's guaranty can be terminated and/or released. If that refinancing does not occur, FirstEnergy may require each co-owner to lend to Global Holding, on a pro rata basis, funds sufficient to prepay the new facility in full. In lieu of providing such funding, the co-owners, at FirstEnergy's option, may provide their several guaranties of Global Holding's obligations under the facility. FirstEnergy receives a fee for providing its guaranty, payable semiannually, which accrues at a rate of 4% through December 31, 2012, 5% from January 1 through December 31, 2013 and, thereafter, a rate per annum equal to the then current Merrill Lynch High Yield 100 index, in each case based upon the average daily outstanding aggregate commitments under the facility for such semiannual period.

OFF-BALANCE SHEET ARRANGEMENTS

FES and certain of the Ohio Companies have obligations that are not included on their Consolidated Balance Sheets related to sale and leaseback arrangements involving the Bruce Mansfield Plant, Perry Unit 1 and Beaver Valley Unit 2, which are satisfied through operating lease payments. The total present value of these sale and leaseback operating lease commitments, net of trust investments, was $1.2 billion as of December 31, 2012. In March 2012, FG, as assignee, provided notice of its irrevocable election of the EBO of the 1987 Bruce Mansfield Plant leases. The purchase price to be paid by FG to complete the EBO under the applicable facility leases aggregates to approximately $435 million, covering both debt and equity under the leases and the fair market value of the applicable leased assets. During 2012, FG acquired certain lessor equity and other interests in connection with exercising the EBO option under the 1987 Bruce Mansfield sale and leaseback transactions for an aggregate purchase price of approximately $262.2 million. Additionally, FG is continuing the appraisal process with one remaining party and is currently involved in litigation with two other parties each of which is disputing the appraisal of the fair market value of the relevant leased assets. During 2012, NG repurchased lessor equity interests in OE's existing sale and leaseback of Beaver Valley Unit 2 for $129 million. From time to time we also enter into discussions with certain parties to the arrangements regarding acquisition of owner participant and other interests. We cannot provide assurance that any such acquisitions will occur on satisfactory terms or at all.

MARKET RISK INFORMATION

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

Commodity Price Risk

FirstEnergy is exposed to financial risks resulting from fluctuating commodity prices, including prices for electricity, natural gas, coal and energy transmission. FirstEnergy's Risk Management Committee is responsible for promoting the effective design and implementation of sound risk management programs and oversees compliance with corporate risk management policies and established risk management practice. FirstEnergy uses a variety of derivative instruments for risk management purposes including forward contracts, options, futures contracts and swaps.

The valuation of derivative contracts is based on observable market information to the extent that such information is available. In cases where such information is not available, FirstEnergy relies on model-based information. The model provides estimates of future regional prices for electricity and an estimate of related price volatility. FirstEnergy uses these results to develop estimates of fair value for financial reporting purposes and for internal management decision making (see Note 8, Fair Value Measurements, of the Combined Notes to Consolidated Financial Statements).

Sources of information for the valuation of commodity derivative contracts assets and liabilities as of December 31, 2012 are summarized by year in the following table:

Source of Information-Fair Value by Contract Year	2013	2014	2015	2016	2017	Thereafter	Total
	(In millions)						
Prices actively quoted[1]	$(3)	$—	$—	$—	$—	$—	$(3)
Other external sources[2]	(46)	(36)	(35)	(20)	—	—	(137)
Prices based on models	(1)	—	—	—	(12)	(148)	(161)
Total[3]	$(50)	$(36)	$(35)	$(20)	$(12)	$(148)	$(301)

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

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

(3) Includes $(398) million in non-hedge commodity derivative contracts that are primarily related to NUG contracts. NUG contracts are generally subject to regulatory accounting and do not materially impact earnings.

FirstEnergy performs sensitivity analyses to estimate its exposure to the market risk of its commodity positions. Based on derivative contracts held as of December 31, 2012, a 10% adverse change in commodity prices would decrease net income by approximately $3 million during the next 12 months.

Interest Rate Risk

FirstEnergy's exposure to fluctuations in market interest rates is reduced since a significant portion of debt has fixed interest rates, as noted in the table below. FirstEnergy is subject to the inherent interest rate risks related to refinancing maturing debt by issuing new debt securities. As discussed in Note 5, Leases of the Combined Notes to Consolidated Financial Statements, FirstEnergy's investments in capital trusts effectively reduce future lease obligations, also reducing interest rate risk.

Comparison of Carrying Value to Fair Value

Year of Maturity	2013	2014	2015	2016	2017	There-after	Total	Fair Value
	(In millions)							
Assets:								
Investments Other Than Cash and Cash Equivalents:								
Fixed Income	$17	$17	$12	$6	$2	$1,861	$1,915	$1,945
Average interest rate	8.6%	8.7%	8.8%	8.9%	8.8%	4.3%	4.4%	
Liabilities:								
Long-term Debt:								

Fixed rate	$923	$878	$1,343	$895	$1,612	$10,297	$15,948	$18,451
Average interest rate	6.8 %	6.1 %	5.1 %	6.0 %	6.1 %	6.1 %	6.1 %	
Variable rate	$200					$809	$1,009	$1,009
Average interest rate	2.0 %					0.1 %	0.5 %	

During 2012, FirstEnergy terminated $1.6 billion forward starting swap agreements on August 16, 2012 resulting in cash proceeds and a pre-tax gain, recorded as a reduction to interest expense, of approximately $6 million. There were no interest rate swaps outstanding as of December 31, 2012.

Equity Price Risk

As of December 31, 2012, the FirstEnergy pension plan assets were approximately 15% in equity securities, 47% in fixed income securities, 22% in absolute return strategies, 5% in real estate, 1% in private equity and 10% in cash and short-term securities. A decline in the value of pension plan assets could result in additional funding requirements. FirstEnergy's funding policy is based on actuarial computations using the projected unit credit method. During the year ended December 31, 2012, FirstEnergy made a voluntary pre-tax contribution to its qualified pension plans of $600 million. See Note 2, Pensions and Other Postemployment Benefits, of the Combined Notes to Consolidated Financial Statements for additional details on FirstEnergy's pension plans and OPEB.

NDT funds have been established to satisfy NG's, OE's, JCP&L's and other FE subsidiaries' nuclear decommissioning obligations. As of December 31, 2012, approximately 75% of the funds were invested in fixed income securities, 15% of the funds were invested in equity securities and 10% were invested in short-term investments, with limitations related to concentration and investment grade ratings. The investments are carried at their market values of approximately $1,581 million, $309 million and $205 million for fixed income securities, equity securities and short-term investments, respectively, as of December 31, 2012, excluding $110 million of net receivables, payables and accrued income. A hypothetical 10% decrease in prices quoted by stock exchanges would result in a $31 million reduction in fair value as of December 31, 2012. JCP&L's decommissioning trust is subject to regulatory accounting, with unrealized gains and losses recorded as regulatory assets or liabilities, since the difference between investments held in trust and the decommissioning liabilities will be recovered from or refunded to customers. NG and OE recognize in earnings the unrealized losses on available-for-sale securities held in their NDT as OTTI. A decline in the value of FirstEnergy's NDT or a significant escalation in estimated decommissioning costs could result in additional funding requirements. During 2012, approximately $4 million was contributed to OE's NDT. FE maintains a $95 million parental guarantee to the NRC relating to a shortfall in nuclear decommissioning funding for Beaver Valley Unit 1 and Perry, and is expected to increase this guarantee to $135 million in 2013.

CREDIT RISK

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

Wholesale Credit Risk

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

Retail Credit Risk

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

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

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

OUTLOOK

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 it 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 competitive retail electric suppliers 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 their public utility affiliates. In addition, if FES, AE Supply or any of their subsidiaries were to engage in the construction of significant new generation facilities in any of those states, they would also be subject to state siting authority.

MARYLAND

PE provides SOS pursuant to a combination of settlement agreements, MDPSC orders and regulations, and statutory provisions. SOS supply is competitively procured in the form of rolling contracts of varying lengths through periodic auctions that are overseen by the MDPSC and a third party monitor. Although settlements with respect to residential SOS for PE customers expired on December 31, 2012, by statute, service continues in the same manner unless changed by order of the MDPSC. The settlement provisions relating to non-residential SOS have also expired, however, by MDPSC order, the terms of service remain in place unless PE requests or the MDPSC orders a change. PE recovers its costs plus a return for providing SOS.

The Maryland legislature in 2008 adopted a statute codifying the EmPOWER Maryland goals to reduce electric consumption by 10% and reduce electricity demand by 15%, in each case by 2015. Expenditures were originally estimated to be approximately $101 million for the PE programs for the period of 2009 to 2015 and would have been recovered over that six-year period. Maryland law only allows for the utility to recover lost distribution revenue attributable to energy efficiency or demand reduction programs through a base rate case proceeding, and to date such recovery has not been sought or obtained by PE. Meanwhile, after extensive meetings with the MDPSC Staff and other stakeholders, on August 31, 2011, PE filed a new comprehensive plan that includes additional and improved programs for the period 2012-2014. The plan is expected to cost approximately $66 million over the three-year period. On December 22, 2011, the MDPSC issued an order approving PE's plan with various modifications and follow-up assignments.

Pursuant to a bill passed by the Maryland legislature in 2011, the MDPSC proposed rules, based on the product of a working group of utilities, regulators and other interested stakeholders, that create specific requirements related to a utility's obligation to address service interruptions, downed wire response, customer communication, vegetation management, equipment inspection, and annual reporting. The bill requires that the MDPSC 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 will be required to assess each utility's compliance with the new rules, and may assess penalties of up to $25,000 per day, per violation. At a hearing on April 17, 2012, the MDPSC approved re-publication of the rules as final. The new rules set utility-specific SAIDI and SAIFI targets for 2012-2015; prescribe detailed tree-trimming requirements, outage restoration and downed wire response deadlines; and impose other reliability and customer satisfaction requirements. PE has advised the MDPSC that compliance with the new rules is expected to increase costs by approximately $106 million over the period 2012-2015.

Following a "derecho" storm through the region on June 29, 2012, the MDPSC convened a new proceeding to consider matters relating to the electric utilities' performance in responding to the storm. Hearings on the matter were conducted in September 2012. Concurrently, Maryland's governor convened a special panel to examine possible ways to improve the resilience of the electric distribution system. On October 3, 2012, that panel issued a report calling for various measures including: acceleration and expansion of some of the requirements contained in the reliability standards that the MDPSC approved on April 17, 2012, and which had become final on May 28, 2012; for selective increased investment in system hardening; for creation of separate recovery mechanisms for the costs of those changes and investments; and penalties or bonuses on returns earned by the utilities based on their reliability performance. The panel's report has been referred to the MDPSC for action.

NEW JERSEY

JCP&L currently provides BGS for retail customers who do not choose a third party EGS and for customers of third party EGSs that fail to provide the contracted service. The supply for BGS, which is comprised of two components, is provided through contracts procured through separate, annually held descending clock auctions, the results of which are approved by the NJBPU. One BGS component and auction, reflecting hourly real time energy prices, is available for larger commercial and industrial customers. The other BGS component and auction, providing a fixed price service, is intended for smaller commercial and residential customers. All New Jersey EDCs participate in this competitive BGS procurement process and recover BGS costs directly from customers as a charge separate from base rates.

On September 7, 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 requested 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. In its written Order issued July 31, 2012, the NJBPU found that a base rate proceeding "will assure that JCP&L's rates are just and reasonable and that JCP&L is investing sufficiently to assure the provision of safe, adequate and proper utility service to its customers" and ordered JCP&L to file a base rate case using a historical 2011 test year. The rate case petition was filed on November 30, 2012. In the filing, JCP&L requested approval to increase its revenues by approximately $31.5 million and reserved the right to update the filing to include costs associated with the impact of Hurricane Sandy. The NJBPU has transmitted the case to the New Jersey Office of Administrative Law for further proceedings and an ALJ has been assigned. Evidentiary hearings in the matter are currently anticipated to commence in September, 2013. On February

22, 2013, JCP&L updated its filing to request recovery of $603 million of distribution-related Hurricane Sandy restoration costs, resulting in increasing the total revenues requested to approximately $112 million.

Pursuant to a formal Notice issued by the NJBPU on September 14, 2011, public hearings were held in September 2011 to solicit comments regarding the state of preparedness and responsiveness of New Jersey's EDCs prior to, during, and after Hurricane Irene, with additional hearings held in October 2011. Additionally, the NJBPU accepted written comments through October 28, 2011 related to this inquiry. 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 selected a consultant to further review and evaluate the New Jersey EDCs' preparation and restoration efforts with respect to Hurricane Irene and the October 2011 snowstorm, and the consultant's report was submitted to and subsequently accepted by the NJBPU on September 12, 2012. JCP&L submitted written comments on the report. On January 24, 2013, based upon recommendations in its consultant's report, the NJBPU ordered the New Jersey EDCs to take a number of specific actions to improve their preparedness and responses to major storms. The order includes specific deadlines for implementation of measures with respect to preparedness efforts, communications, restoration and response, post event and underlying infrastructure issues. JCP&L is developing an appropriate plan to implement the required measures.

OHIO

The Ohio Companies primarily operate under an ESP, which expires on May 31, 2014. The material terms of the ESP include:
- Generation supplied through a CBP;
- A load cap of no less than 80%, so that no single supplier is awarded more than 80% of the tranches, 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, 2016 or when the amount of costs avoided by customers for certain types of products totals $360 million. The Ohio Companies have also agreed, subject to the outcome of certain PJM proceedings, 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.

On April 13, 2012, the Ohio Companies filed an application with the PUCO to essentially extend the terms of their current ESP for two years. The ESP 3 Application was approved by the PUCO on July 18, 2012. Several parties timely filed applications for rehearing, which the PUCO granted on September 12, 2012, solely for the purpose of giving the PUCO additional time to consider the issues raised in the applications for rehearing. The PUCO issued an Entry on Rehearing on January 30, 2013 denying all applications for rehearing.

As approved, the ESP 3 plan continues certain provisions from the current ESP including:
- Continuing the current base distribution rate freeze through May 31, 2016;
- Continuing to provide economic development and assistance to low-income customers for the two-year extension period at levels established in the existing ESP;
- Providing Percentage of Income Payment Plan customers with a 6% generation rate discount;
- Continuing to provide power to shopping and to non-shopping customers as part of the market-based price set through an auction process; and

- Continuing Rider DCR that allows continued investment in the distribution system for the benefit of customers.

As approved, the ESP 3 plan will provide additional provisions, including:

- Securing generation supply for a longer period of time by conducting an auction for a three-year period rather than a one-year period, in each of October 2012 and January 2013, to mitigate any potential price spikes for the Ohio Companies' utility customers who do not switch to a competitive generation supplier; and
- Extending the recovery period for costs associated with purchasing RECs mandated by SB221 through the end of the new ESP 3 period. This is expected to initially reduce the monthly renewable energy charge for all non-shopping utility customers of the Ohio Companies by spreading out the costs over the entire ESP period.

Under the provisions of SB221, the Ohio Companies are required to implement energy efficiency programs that will achieve a total annual energy savings equivalent of approximately 1,211 GWHs in 2012 (an increase of 416,000 MWHs over 2011 levels), 1,726 GWHs in 2013, 2,306 GWHs in 2014 and 2,903 GWHs for each year thereafter through 2025. The Ohio Companies 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 their three-year portfolio plan, as required by SB221, seeking approval for the programs they intended to implement to meet the energy efficiency and peak demand reduction requirements for the 2010-2012 period. In March 2011, the PUCO issued an Opinion and Order generally approving the Ohio Companies' 2010-2012 portfolio plan which provides for recovery of all costs associated with the programs, including lost revenues. The Ohio Companies have implemented

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those programs included in the plan. 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.

The Ohio Companies had filed an application for rehearing regarding portions of the PUCO's decision related to the Ohio Companies' three-year portfolio plan, which was later denied by the PUCO and the subsequent appeal was dismissed by the Supreme Court of Ohio. In accordance with PUCO Rules and a PUCO directive, the Ohio Companies filed their next three-year portfolio plan for the period January 1, 2013 through December 31, 2015 on July 31, 2012. Estimated costs for the three Ohio Companies' plans total approximately $250 million over the three-year period. Hearings were held with the PUCO in October 2012. Because the next three year-plans would not be approved until after 2012, the Ohio Companies filed a motion with the PUCO to extend their existing energy efficiency programs and related cost recovery until the new plans are approved. This motion was approved on December 12, 2012.

Additionally, under SB221, electric utilities and electric service companies in Ohio were 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 and in August 2010, 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 August 2011, the Ohio Companies conducted two RFP processes to obtain RECs to meet the statutory benchmarks for 2011 and beyond. On September 20, 2011 the PUCO opened a new docket to review the Ohio Companies' alternative energy recovery rider. The PUCO selected auditors to perform a financial and management audit, and final audit reports were filed with the PUCO on August 15, 2012. While generally supportive of the Ohio Companies' approach to procurement of RECs, the management/performance auditor recommended the PUCO examine, for possible disallowance, certain costs associated with the procurement of In-State All Renewable obligations that the auditor characterized as excessive. A hearing for this matter commenced on February 19, 2013. In March 2012, the Ohio Companies conducted an RFP process to obtain SRECs to help meet the statutory benchmarks for 2012 and beyond. With the successful completion of this RFP, the Ohio Companies achieved their in-state solar compliance requirements for 2012. The Ohio Companies also held a short-term RFP process to obtain all state SRECs and both in-state and all state non-solar RECs to help meet the statutory benchmarks for 2012. With the successful completion of this RFP, the Ohio Companies also achieved their in-state and all-state solar compliance requirements for 2012. The Ohio Companies intend to conduct an RFP in 2013 to cover their all-state SREC and their in-state and all-state REC compliance obligations.

The PUCO instituted a statewide investigation on December 12, 2012 to evaluate the vitality of the competitive retail electric service market in Ohio. The PUCO provided interested stakeholders the opportunity to provide comments on twenty-two questions by March 1, 2013, with reply comments due on March 29, 2013. The questions posed are categorized as market design and corporate separation. The Ohio Companies plan to provide their comments by the deadline, but cannot predict the outcome of this investigation.

PENNSYLVANIA

The Pennsylvania Companies currently operate under DSPs that expire May 31, 2013, and provide for the competitive procurement of generation supply for customers that do not choose an alternative EGS or for customers of alternative EGSs that fail to provide the contracted service. The default service supply is currently provided by wholesale suppliers through a mix of long-term and short-term contracts procured through descending clock auctions, competitive requests for proposals and spot market purchases. On November 17, 2011, the Pennsylvania Companies filed a Joint Petition for Approval of their DSPs that will provide the method by which they will procure the supply for their default service obligations for the period of June 1, 2013 through May 31, 2015. The ALJ issued a

Recommended Decision on June 15, 2012, that supported adoption of the Pennsylvania Companies' proposed wholesale procurement plans, denial of their proposed Market Adjustment Charge, and various modifications to the proposed competitive enhancements. The PPUC entered an opinion and order on August 16, 2012, which primarily resolved those issues related to procurement and rate design, but required the submission of revised proposals regarding the retail market enhancement programs. The Pennsylvania Companies filed revised proposals on the retail market enhancements on November 14, 2012. A final order was entered on February 15, 2013, which addressed minor changes to the Pennsylvania Companies' revised enhancement proposals and ordered two choices for cost recovery of those programs.

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, and directed ME and PN to submit a new tariff or tariff supplement reflecting the removal of marginal transmission losses from the TSC. Pursuant to a plan approved by the PPUC, ME and PN 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 losses are refunded. In April 2010, ME and PN 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 ME's and PN's TSC riders. ME and PN filed a Petition for Allowance of Appeal with the Pennsylvania Supreme Court, which was denied on February 28, 2012. On June 27, 2012, ME and PN filed a Petition for Writ of Certiorari with the Supreme Court of the United States. The certiorari petition sought review of the Pennsylvania State Court decisions. On October 9, 2012, the Supreme Court denied that petition. On July 13, 2011, ME and PN also filed a complaint in the U.S. District Court for the Eastern District of Pennsylvania for the purpose of obtaining an order that would enjoin enforcement of the PPUC and

Pennsylvania court orders under a theory of federal preemption on the question of retail rate recovery of the marginal transmission loss charges. Proceedings in the U.S. District Court effectively were suspended until conclusion of the proceedings before the United States Supreme Court. When that court issued its ruling on October 9, 2012, the U.S. District Court proceedings returned to active status. Pursuant to procedural orders issued by U.S. District Court Judge Gardner, on December 21, 2012, the PPUC submitted its motion to dismiss the U.S. District Court proceedings. ME and PN submitted their answers on January 9, 2013, and subsequent pleadings were submitted by the PPUC, ME and PN. Oral argument on the PPUC motion to dismiss is scheduled for May 2013.

In each of May 2008, 2009 and 2010, the PPUC approved ME's and PN'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 transmission 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 ME's customers to provide for full recovery by December 31, 2010. Although the ultimate outcome of this matter cannot be determined at this time, ME and PN believe that they should ultimately prevail through the judicial process and therefore expect to fully recover the approximately $254 million in marginal transmission losses for the period prior to January 1, 2011.

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 on utilities that fail to achieve the required reductions in consumption and peak demand. The Pennsylvania Companies submitted a final report on November 15, 2011, in which they reported on their compliance with statutory May 31, 2011, energy efficiency benchmarks. ME, PN 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 could be subject to a statutory penalty of up to $20 million and is unable to predict the outcome of this matter.

Pursuant to Act 129, the PPUC was charged with reviewing the cost effectiveness of energy efficiency and peak demand reduction programs. The PPUC found the energy efficiency programs to be cost effective and in an Order entered on August 3, 2012, the PPUC directed all of the electric utilities in Pennsylvania to submit by November 1, 2012, a Phase II EE&C Plan that would be in effect for the period June 1, 2013 through May 31, 2016. Due to Hurricane Sandy, this deadline was extended until November 15, 2012. A hearing on the level of the Pennsylvania Companies' respective Phase II energy efficiency targets as established by the PPUC was held on October 19, 2012. The PPUC denied the Pennsylvania Companies' request for adjustments to these targets on December 5, 2012. The PPUC has deferred ruling on the need to create peak demand reduction targets until it receives more information from the EE&C statewide evaluator. The Pennsylvania Companies filed their Phase II plans and supporting testimony in November 2012. On January 16, 2013, the Pennsylvania Companies reached a settlement with all but one party on all but one issue. The settlement provides for the Pennsylvania Companies to meet with interested parties to discuss ways to expand upon the EE&C programs and incorporate any such enhancements after the plans are approved, provided that these enhancements will not jeopardize the Pennsylvania Companies' compliance with their required targets or exceed the statutory spending caps. On February 6, 2013, the Pennsylvania Companies filed revised Phase II EE&C Plans to conform the plans to the terms of the settlement. The remaining issue, raised by a natural gas company, involved the recommendation that the Pennsylvania Companies include in their plans incentives for natural gas space and water heating appliances. This issue was litigated on January 17, 2013. Initial and reply briefs were submitted on January 28, 2013 and February 6, 2013, respectively. The evidentiary record was certified on February 7, 2013, with an order on these plans expected to be issued by the PPUC no later than the end of the first quarter of 2013.

In addition, Act 129 required utilities to file a SMIP with the PPUC. 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 its previously approved smart meter deployment plan and certain smart meter dependent aspects of the EE&C Plan. 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. WP also proposed to 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 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. A joint settlement with all parties based on these terms, with one party retaining the ability to challenge the recovery of amounts spent on WP's original SMIP, was approved by the PPUC on June 30, 2011. Additionally, WP would be permitted to seek recovery of certain other costs as part of its revised SMIP or in a future base distribution rate case.

On December 31, 2012, the Pennsylvania Companies filed their Deployment Plan. A prehearing conference was held on February 19, 2013 and evidentiary hearings will commence on May 8, 2013. The Deployment Plan requests deployment over the period 2013 to 2019, with an estimated cost of completion of about $1.25 billion. Such costs are expected to be recovered through the Pennsylvania Companies' PPUC-approved Riders SMT-C.

In the PPUC Order approving the FirstEnergy and Allegheny merger, the PPUC announced that a separate statewide investigation into Pennsylvania's retail electricity market would 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 to investigate both intermediate and long term plans that could be adopted to further foster the competitive markets, and to explore the future of default service in Pennsylvania following the expiration of the upcoming DSPs on May 31, 2015. A Tentative Order was entered by the PPUC on November 8, 2012, seeking comments regarding the end state of default service and related issues. The Pennsylvania Companies and FES filed comments on December 10, 2012. A final order was issued on February 15, 2013 providing recommendations on the entities to provide default service, the products to be offered, billing options, customer education, and licensing fees and assessments, among other items.

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 electricity 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 was published on February 11, 2012, and comments were filed by the Pennsylvania Companies and FES on March 27, 2012. If implemented these rules could require a significant change in the ways FES and the Pennsylvania Companies do business in Pennsylvania, and could possibly have an adverse impact on their results of operations and financial condition. Pennsylvania's Independent Regulatory Review Commission subsequently issued comments on the proposed rulemaking on April 26, 2012, which called for the PPUC to further justify the need for the proposed revisions by citing a lack of evidence demonstrating a need for them. The House Consumer Affairs Committee of the Pennsylvania General Assembly also sent a letter to the Independent Regulatory Review Commission on July 12, 2012, noting its opposition to the proposed regulations as modified.

WEST VIRGINIA

In April 2010, MP and PE filed with the WVPSC a Joint Stipulation and Agreement of Settlement reached with the other parties in a proceeding for an annual increase in retail rates that provided for:

- $40 million annualized base rate increases effective June 29, 2010;
- Deferral of February 2010 storm restoration expenses over a maximum five-year period;
- Additional $20 million annualized base rate increase effective in January 2011;
- Decrease of $20 million in ENEC rates effective January 2011, providing for deferral of related costs for later recovery in 2012; and
- Moratorium on filing for further increases in base rates before December 1, 2011, except under specified circumstances.

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

In February 2011, MP and PE filed a petition with the WVPSC seeking an order declaring that MP owns all RECs associated with the energy and capacity that MP is required to purchase pursuant to electric energy purchase agreements between MP and three NUG facilities in West Virginia. The City of New Martinsville and Morgantown

Energy Associates, each the owner of one of the contracted resources, have participated in the case in opposition to the petition. The WVPSC issued an order on November 22, 2011, granting ownership of all RECs produced by the facilities to MP, and holding that an electric utility that purchases electric energy and capacity under an electric power purchase agreement with a Qualifying Facility under PURPA owns the RECs associated with that purchase. The RECs are being used for compliance purposes. The West Virginia Supreme Court issued an Order on June 11, 2012, upholding the WVPSC's decision. The City of New Martinsville and Morgantown Energy Associates filed petitions at FERC alleging the WVPSC order violated PURPA and requesting that FERC initiate an enforcement action. On April 24, 2012, FERC ruled that FERC jurisdictional contracts for the sale of Qualifying Facility capacity entered into under PURPA are intended to pay only for electric energy and capacity (and not for RECs), and that state law controlled on the issues of determining which entity owns RECs and how they are transferred between entities. FERC declined to act on the petitions and instead noted that the City of New Martinsville and Morgantown Energy Associates could file complaints in the U.S. District Court. FERC also noted there may be language in the WVPSC order that is inconsistent with PURPA. MP and PE filed for rehearing of FERC's order taking the position that the WVPSC order is consistent with PURPA, which was denied by FERC on September 20, 2012. The City of New Martinsville filed a complaint in the U.S. District Court for the Southern District of West Virginia on June 1, 2012, alleging that the WVPSC order violates PURPA. Morgantown Energy Associates has joined in filing a similar complaint and requesting damages in the same U.S. District Court. MP and PE filed for judgment on the pleadings in both cases on January 25, 2013.

The WVPSC has proceedings for each West Virginia electric utility to establish reliability targets for distribution performance. The parties entered into a settlement in September 2012 resolving all issues and revising performance targets beginning in 2014. The settlement has been approved by the WVPSC.

The WVPSC opened a general investigation into the June 29, 2012, derecho windstorm with data requests for all utilities. A public meeting for presentations on utility responses and restoration efforts was held on October 22, 2012 and two public input hearings have been held. The WVPSC issued an Order in this matter on January 23, 2013 closing the proceeding and directing electric utilities to file a vegetation management plan within six months and to propose a cost recovery mechanism. This Order also requires MP and PE to file a status report regarding improvements to their storm response procedures by the same date.

The West Virginia ENEC fuel case was filed by MP and PE at the WVPSC in August 2012 with a projected over-recovery of approximately $66 million under then current rates for the next year, January 1, 2013 through December 31, 2013. MP and PE proposed no change in overall rates on January 1, 2013; however, MP and PE proposed establishing a separate regulatory liability for the difference between the recommended 2013 ENEC rates and the current ENEC rates. This estimated $66 million liability was proposed to offset the rate relief MP and PE seek to become effective with the completion of a proposed generation resource acquisition transaction described below. A hearing was held in December 2012 in the ENEC fuel case and the WVPSC denied MP and PE's request to delay the $66 million rate decrease and ordered that the fuel rate decrease be implemented on January 1, 2013.

MP and PE filed their Resource Plan with the WVPSC in August 2012 detailing both supply and demand forecasts and noting a substantial capacity deficiency. MP and PE have filed a Petition for approval of a Generation Resource Transaction with the WVPSC in November 2012 that proposes a net ownership transfer of 1,476 MW of coal-fired generation capacity to MP by May 2013. The proposed transfer would involve MP's acquisition of the remaining ownership of the Harrison Power Station from AE Supply and the sale of MP's minority interest in the Pleasants Power Station to AE Supply. The proposed transfer would implement a cost-effective plan to assist MP in meeting its energy and capacity obligations with its own generation resources, eliminating the need to make unhedged electricity and capacity purchases from the spot market, which is expected to result in greater rate stability for MP's customers. The plan is expected to remedy MP's capacity and energy shortfalls, which are projected to worsen due to a projected increase in annual load growth of approximately 1.4%. MP and PE also filed with FERC for authorization to effect these transfers. MP and PE will file a base rate case no later than six months from the completion of the transaction. On February 11, 2013, the WVPSC issued an order adopting a procedural schedule for this matter with hearings scheduled for May 29-31, 2013.

RELIABILITY MATTERS

Federally-enforceable mandatory reliability standards apply to the bulk electric system and impose certain operating, record-keeping and reporting requirements on the Utilities, FES, AE Supply, FG, FENOC, ATSI and TrAIL. 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 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.

FERC MATTERS

PJM Transmission Rate

PJM and its stakeholders have been debating the proper method to allocate costs for new transmission facilities. While FirstEnergy and other parties advocated for a traditional "beneficiary pays" (or usage based) approach, others advocate for “socializing” the costs on a load-ratio share basis - each customer in the zone would pay based on its total usage of energy within PJM. This debate is framed by regulatory and court decisions. On August 6, 2009, the U.S. Court of Appeals for the Seventh Circuit found that FERC had not supported a prior FERC decision to allocate costs for new 500 kV and higher voltage facilities on a load ratio share basis and, based on that finding, remanded the rate design issue to FERC. In an order dated January 21, 2010, FERC set this matter for a “paper hearing” and requested parties to submit written comments. FERC identified nine separate issues for comment and directed PJM to file the first round of comments. PJM filed certain studies with FERC on April 13, 2010, which demonstrated that allocation of the cost of high voltage transmission facilities on a beneficiary pays basis results in certain LSEs in PJM bearing the majority of the costs. Subsequently, numerous parties, including FirstEnergy, 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 utility commissions supported the use of the beneficiary pays approach for cost allocation for high voltage transmission facilities. Other utilities and state utility commissions supported continued socialization of these costs on a load ratio share basis. On March 30, 2012, FERC issued an order on remand reaffirming its prior decision 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 (or socialization) rate based on the amount of load served in a transmission zone and concluding that such methodology is just and reasonable and not unduly discriminatory or preferential. On April 30, 2012, FirstEnergy requested rehearing of FERC's March 30, 2012 order. FirstEnergy's request for rehearing remains pending before FERC.

Order No. 1000, issued by FERC on July 21, 2011, required the submission of a compliance filing by PJM or the PJM transmission owners demonstrating that the cost allocation methodology for new transmission projects directed by the PJM Board of Managers satisfied the principles set forth in the order. To demonstrate compliance with the regional cost allocation principles of the order, the PJM transmission owners, including FirstEnergy, submitted a filing to FERC on October 11, 2012, proposing a hybrid method of 50% beneficiary pays and 50% postage stamp to be effective for RTEP projects approved by the PJM Board of Managers on and after the effective date of the compliance filing. On January 31, 2013, FERC conditionally accepted the hybrid method to be effective on February 1, 2013, subject to refund and to a future order on PJM's separate Order No. 1000 compliance filing. FERC stated that it will address the merits of the PJM transmission owners' October 11, 2012 filing, including comments, protests and answers submitted in regard thereto, in its future order on PJM's compliance filing. Filings to demonstrate compliance with the interregional cost allocation principles of the order are due to FERC by April 2013.

RTO Realignment

On June 1, 2011, ATSI and the ATSI zone transferred from MISO to 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. While most of the matters involved with the move have been resolved, the question of ATSI's responsibility for certain costs for the “Michigan Thumb” transmission project continues to be disputed; the details of the dispute are discussed below under "MISO Multi-Value Project Rule Proposal." In addition, FERC denied recovery of certain charges that collectively can be described as "exit fees" by means of ATSI's transmission rate totaling approximately $78.8 million until such time as ATSI submits a cost/benefit analysis that demonstrates net benefits to customers from the move. ATSI has asked for rehearing of FERC's orders that address the Michigan Thumb transmission project and the exit fee issue. On December 21, 2012, ATSI and other parties filed a proposed settlement agreement with FERC that, if accepted by FERC, should resolve certain of the exit fee issues. Thereafter, the OCC protested the December 21, 2012 settlement filing, which remains pending before FERC. In a prior order, FERC ruled that the costs for certain "legacy RTEP" transmission projects in PJM could be charged to transmission customers in the ATSI zone. ATSI sought rehearing of the question of whether the ATSI zone should pay these legacy RTEP charges and, on September 20, 2012, FERC denied ATSI's request for rehearing. On November 19, 2012, ATSI filed a petition for review with the D.C. Circuit Court of Appeals of FERC's ruling on the "legacy RTEP" issue.

The 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 (not including ATSI or FirstEnergy) jointly filed with FERC a proposed cost allocation methodology for certain new transmission projects. The new transmission projects - described as MVPs - are a class of transmission projects that are approved via MISO's MTEP process. Under MISO's proposal, the costs of “Michigan Thumb” MVP project that was 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 and charged to ATSI. MISO estimated that approximately $16 million in annual revenue requirements associated with the Michigan Thumb Project would be allocated to the ATSI zone upon completion of project construction.

FirstEnergy has filed pleadings in opposition to the MISO's efforts to “socialize” the costs of the Michigan Thumb Project onto ATSI or onto ATSI's customers. FirstEnergy asserts legal, factual and policy arguments. To date, FERC has responded in a series of orders that may require ATSI to absorb the charges for the Michigan Thumb Project pending the outcome of further regulatory proceedings and appeals. These further proceedings can be divided into two classes: litigation related to MISO's generic MVP cost allocation proposal; and litigation related to MISO's "Schedule 39" tariff that purports to charge the MVP costs to ATSI.

On October 31, 2011, FirstEnergy filed a Petition of Review of certain of FERC's orders that address the generic MVP tariffs 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. Briefs were due from the parties through 2012 and early 2013, and oral arguments will be scheduled in 2013.

In February 2012, FERC accepted the MISO's proposed Schedule 39 tariff, subject to hearings and potential refund of MVP charges to ATSI. MISO's Schedule 39 tariff is the vehicle through which the MISO plans to charge the Michigan Thumb Project costs to ATSI. FERC set for hearing the question of whether it is just and reasonable for ATSI to pay the Michigan Thumb Project costs and, if so, the amount of and methodology for calculating ATSI's Michigan Thumb Project cost responsibility. The hearings are expected to start in April 2013.

FirstEnergy cannot predict the outcome of these proceedings 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 several 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 had previously remanded one of those proceedings to FERC, which dismissed the claims of the California Parties in May 2011, and affirmed the dismissal in June 2012. On June 20, 2012, the California Parties appealed FERC's decision back to the Ninth Circuit. The timing of further action by the Ninth Circuit is unknown.

In another proceeding, in June 2009, the California Attorney General on behalf of certain California parties, filed another complaint with FERC against various sellers, including AE Supply, again seeking refunds for transactions in the California energy markets during 2000 and 2001. The above-noted transactions with CDWR are the basis for including AE Supply in this complaint. AE Supply filed a motion to dismiss, which was granted by FERC in May 2011, and affirmed by FERC in June 2012. The California Attorney General has appealed FERC's dismissal of its complaint to the Ninth Circuit, which has consolidated the case with other pending appeals related to California refund claims, and stayed the proceedings pending further order.

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 was proposed to be comprised of a 765 kV transmission line 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. On August 24, 2012, the PJM Board of Managers canceled the PATH project, which it had originally suspended in February 2011. All applications for authorization to construct the project filed with state commissions have been withdrawn. As a result, approximately $62 million and approximately $59 million in costs incurred by PATH-Allegheny and PATH-WV, respectively, were reclassified from net property, plant and equipment to a regulatory asset for future recovery. On September 28, 2012, those companies requested authorization from FERC to recover the costs with a proposed return on equity of 10.9% (10.4% base plus 0.5% RTO membership) from PJM customers over the next five years. Several parties protested the request. On November 30, 2012, FERC issued an order denying the 0.5% return on equity adder for RTO membership and allowing the tariff changes enabling recovery of these costs to become effective on December 1, 2012 subject to settlement judge procedures and hearing if the parties do not agree to a settlement. The issues subject to settlement include the prudence of the costs, the base return on equity and the period of recovery. Depending on the outcome of a possible settlement or hearing, if settlement is not achieved, PATH-Allegheny and PATH-WV may be required to refund certain amounts that have been collected under their formula rate.

PATH-Allegheny and PATH-WV have requested rehearing of FERC's denial of the 0.5% return on equity adder for RTO membership; that request for rehearing remains pending before FERC. In addition, FERC has consolidated for settlement judge procedures and hearing purposes two formal challenges to the PATH formula rate annual updates submitted to FERC in June 2010 and June 2011. FirstEnergy cannot predict the outcome of these matters or estimate the possible loss or range of loss.

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 owns the remaining interest in the plant. The project was constructed in the early 1960s, and became operational in 1965. FERC issued a license for authorization to operate the project. 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 the NEPA), and provide opportunities for intervention and protests by affected third parties. FERC may hold hearings during the five-year ILP licensure process. FirstEnergy expects FERC to issue the new license in the first quarter of 2013. To the extent 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.

On June 29, 2012, FERC Staff sent an 'Additional Information Request' to JCP&L. In the request, FERC Staff voiced concern about JCP&L's proposed 'fusegate' overflow structure, and asked for additional information and analysis that would support a FERC decision to authorize installation of this structure. JCP&L and FERC Staff subsequently agreed that JCP&L would install the proposed fusegate overflow structure. In spring 2012, the New Jersey State Historic Preservation Office asked that JCP&L agree to additional measures to protect certain prehistoric sites that are located on the Yards Creek property. JCP&L was able to negotiate an agreement for such protections, which was executed as of February 5, 2013. At this time, we expect that JCP&L's license application will be uncontested and that FERC will renew the license in the first quarter of 2013.

Seneca

The Seneca Pumped Storage Project is a 451 MW hydroelectric project located in Warren County, Pennsylvania owned and operated by FG. FG 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, FG initiated the ILP relicensing process by filing its notice of intent to relicense and related documents in the license docket.

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. On November 30, 2010, the Seneca Nation filed its notice of intent to relicense and related documents necessary for the Seneca Nation to submit a competing application. FG believes it is entitled to a statutory “incumbent preference” under Section 15 and that it ultimately should prevail in these proceedings. Nevertheless, the Seneca Nation's pleadings reflect the Nation's apparent intent to obtain the license for the facility, and to assume ownership and operation of the facility as contemplated by the statute.

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 January 7, 2013, FirstEnergy and the Seneca Nation submitted their respective reports for the 2012 study season. On January 31 and February 1, 2013, respectively, the Seneca Nation and FirstEnergy each submitted their respective proposed study plans for the 2013 study season. The study processes will extend through approximately November 2013.

MISO Capacity Portability

On June 11, 2012, FERC issued a Notice of Request for Comments regarding whether existing rules on transfer capability act as barriers to the delivery of capacity between MISO and PJM. FERC is responding to suggestions from MISO and the MISO stakeholders that PJM's rules regarding the criteria and qualifications for external generation capacity resources be changed to ease participation by resources that are located in MISO in PJM's RPM capacity auctions. FirstEnergy submitted comments on August 10, 2012, and reply comments on August 27, 2012. In the fall of 2012, FirstEnergy participated in certain stakeholder meetings to review various proposals advanced by MISO. Although none of MISO's proposals attracted significant stakeholder support, on January 3, 2013, MISO filed a pleading with FERC that renewed many of the arguments advanced in prior MISO filings and asked FERC to take expedited action to address MISO's allegations. On January 18, 2013, FirstEnergy and other parties submitted filings explaining that MISO's concerns largely are without foundation and suggesting that FERC order that the remaining concerns be addressed in the existing stakeholder process that is described in the PJM/MISO Joint Operating Agreement. Changes to the criteria and qualifications for participation in the PJM RPM capacity auctions could have a significant impact on the outcome of those auctions, including a negative impact on the prices at which those auctions would clear.

MOPR Reform

On December 7, 2012, PJM filed amendments to its tariff to revise the MOPR used in the RPM. PJM revised the MOPR to add two broad, categorical exemptions, eliminate an existing exemption, and to limit the applicability of the MOPR to certain capacity resources. The filing also included related and conforming changes to the RPM posting requirements and to those provisions describing the role of the Independent Market Monitor for the PJM Region. PJM proposed an effective date for these Tariff changes of February 5, 2013. FirstEnergy submitted comments on December 28, 2012, and reply comments on January 25, 2013. FERC has not issued an order on the proposed reforms. On February 5, 2013, FERC Staff issued a deficiency letter to PJM requesting additional information on certain components of the proposed MOPR reforms, including the exemptions and resources qualifying for the MOPR. PJM has 30 days to respond to FERC Staff's requests. Changes to the MOPR could have a significant impact on the outcome of the RPM auctions, including a negative impact on the prices at which those auctions would clear.

Synchronous Condensers

On December 20, 2012, FERC approved the transfer by FG to ATSI of certain deactivated generation assets associated with Eastlake Units 1 through 5 and Lakeshore Unit 18 to facilitate their conversion to synchronous condensers to provide voltage support on the ATSI transmission system. The transfer price of the assets is approximately $21.5 million and the estimated conversion cost is approximately $60 million. The transfer of Eastlake Units 4 and 5 was completed on January 31, 2013 and ATSI's completion of the conversion of those units to synchronous condensers is expected to be completed by June 1, 2013 for Eastlake Unit 5 and by December 1, 2013 for Eastlake Unit 4. The transfer of the remaining units and their conversion to synchronous condensers will occur when the use of the units for RMR purposes is no longer required. On January 22, 2013, ATSI requested clarification or, in the alternative, rehearing with respect to a statement in the FERC order authorizing the transfer that ATSI's current formula rate does not include the accounts and components necessary to allow for recovery of the costs associated with acquisition of the transferred assets and that ATSI must make a filing under Section 205 of the FPA in order to recover those costs. ATSI believes its formula rate currently includes the necessary accounts and components to allow for such recovery and that a Section 205 filing is not required. That request for rehearing remains pending before FERC.

FTR Underfunding Complaint

In PJM, FTRs are a mechanism to hedge congestion and operate as a financial replacement for physical firm transmission service. FTRs are financially-settled instruments that entitle the holder to a stream of revenues based on the hourly congestion price differences across a specific transmission path in the PJM Day-ahead Energy Market. However, due to certain language in the PJM tariff, the funds that are set aside to pay FTRs can be diverted to other uses, resulting in “underfunding” of FTR payments. Since June of 2010, FES and AE Supply have lost more than $55 million in revenues that they are entitled to receive as FTR holders to hedge congestion costs. FES and AE Supply continue to experience significant underfunding.

On December 28, 2011, FES and AE Supply filed a complaint with FERC for the purpose of modifying certain provisions in the PJM tariff to eliminate FTR underfunding. On March 2, 2012, FERC issued an order dismissing the complaint. In its order, FERC ruled that it was not appropriate to initiate action at that time because of the unknown root causes of FTR underfunding.FERC directed PJM to convene stakeholder proceedings for the purpose of determining the root causes of the FTR underfunding. FERC went on to note that its dismissal of the complaint was without prejudice to FES and AE Supply or any other affected entity filing a complaint if the stakeholder proceedings proved unavailing. FES and AE Supply sought rehearing of FERC's order and, on July 19, 2012, FERC denied rehearing. In April, 2012, PJM issued a report on FTR underfunding. However, the PJM stakeholder process proved unavailing as the stakeholders were not willing to change the tariff to eliminate FTR underfunding. Accordingly, on February 15, 2013, FES and AE Supply refiled their complaint for the purpose of changing the PJM tariff to eliminate FTR underfunding. This complaint is pending before FERC.

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, utilizing combustion controls and post-combustion controls, generating more electricity from lower or non-emitting plants and/or using emission allowances.

In July 2008, three complaints representing multiple plaintiffs were filed against FG 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 complaint was filed on behalf of twenty-one individuals and the other is a class action complaint seeking certification as a class with the eight named plaintiffs as the class representatives. FG believes the claims are without merit and intends to vigorously 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 possible loss or range of loss.

In December 2007, the states of New Jersey and Connecticut filed CAA citizen suits in the U.S. District Court for the Eastern District of Pennsylvania 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 ME in 1999) and ME. Specifically, these suits allege that "modifications" at Portland Units 1 and 2 occurred between 1980 and 2005 without pre-construction 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. The Court dismissed New Jersey's and Connecticut's claims for injunctive relief against ME, but denied ME's motion to dismiss the claims for civil penalties. In February 2012, GenOn announced its plans to deactivate the Portland Station in January 2015 citing EPA emissions limits and compliance schedules to reduce SO_2 air emissions by approximately 81% at the Portland Station by January 6, 2015. On July 27, 2012, FirstEnergy filed a motion for summary judgment arguing the Plaintiff's remaining claims for civil penalties are barred by the statute of limitations. On November 1, 2012, the other defendants and the plaintiffs filed motions for summary judgment regarding various claims. On February 22, 2013, the Court heard oral argument on the motions for summary judgment and a jury trial regarding liability was set for April 23, 2013. The parties dispute the scope of ME's indemnity obligation to and from Sithe Energy. FirstEnergy believes the claims are without merit and intends to vigorously 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 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. ME, JCP&L and PN, as former owners of the facilities, are unable to predict the outcome of this matter or estimate the possible loss or range of loss.

In January 2011, the U.S. DOJ filed a complaint against PN in the U.S. District Court for the Western District of Pennsylvania seeking injunctive relief against PN based on alleged "modifications" at the coal-fired Homer City generating plant during 1991 to 1994 without pre-construction 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 filed separate complaints regarding Homer City seeking injunctive relief and civil penalties. In October 2011, the Court dismissed all of the claims with prejudice of the U.S. DOJ and the Commonwealth of Pennsylvania and the states of New Jersey and New York against all of the defendants, including PN. 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 which has scheduled oral argument on May 17, 2013. PN believes the claims are without merit and intends to vigorously defend itself against the allegations made in these complaints. The parties dispute the scope of NYSEG's and PN's indemnity obligation to and from Edison International. PN is unable to predict the outcome of this matter or estimate the loss or possible range of loss.

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. 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. FG intends to comply with the CAA and Ohio regulations; 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. In September 2007, AE 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. On June 29, 2012 and January 31, 2013, EPA issued additional CAA section 114 requests for the Harrison coal-fired plant seeking information and documentation relevant to its operation and maintenance, including capital projects undertaken since 2007. AE intends to comply with the CAA but, at this time, is unable to predict the outcome of this matter or estimate the possible loss or range of loss.

In June 2005, the PA DEP and the Attorneys General of New York, New Jersey, Connecticut and Maryland filed suit against AE, AE Supply and the Allegheny Utilities in the U.S. District Court for the Western District of Pennsylvania alleging, among other things, that Allegheny performed major modifications in violation of the PSD provisions of the CAA and the Pennsylvania Air Pollution Control Act at the coal-fired Hatfield's Ferry, Armstrong and Mitchell Plants in Pennsylvania. A non-jury trial on liability only was held in September 2010. The parties are awaiting a decision from the District Court, but there is no deadline for that decision. FirstEnergy is unable to predict the outcome or estimate the possible loss or range of loss.

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 decided that CAIR violated the CAA but 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 decision. In July 2011, the EPA finalized 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 December 30, 2011, CSAPR was stayed by the U.S. Court of Appeals for the District of Columbia Circuit and was ultimately vacated by the Court on August 21, 2012. On January 24, 2013, EPA and intervenors' petitions seeking rehearing or rehearing en banc were denied by the U.S. Court of Appeals for the District of Columbia Circuit. The Court has ordered EPA to continue administration of CAIR until it finalizes a valid replacement for CAIR. Depending on the outcome of these proceedings and how any final rules are ultimately implemented, FG's and AE Supply's future cost of compliance may be substantial and changes to FirstEnergy's operations may result.

Hazardous Air Pollutant Emissions

On December 21, 2011, the EPA finalized the MATS imposing emission limits for mercury, PM, and HCL for all existing and new coal-fired electric generating units effective in April 2015 with 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. On December 28, 2012, the WVDEP granted a conditional exemption through April 16, 2016 for MATS compliance at the Fort Martin, Harrison and Pleasants Power stations. In addition, an EPA enforcement policy document contemplates up to an additional year to achieve compliance,

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through April 2017, under certain circumstances for reliability critical units. MATS has been challenged in the U.S. Court of Appeals for the District of Columbia Circuit by various entities, including FirstEnergy's challenge of the PM emission limit imposed on petroleum coke boilers, such as Bay Shore Unit 1. FirstEnergy and other entities have also petitioned EPA to reconsider and revise various regulatory requirements under MATS. Depending on the outcome of these proceedings and how the MATS are ultimately implemented, FirstEnergy's future cost of compliance with MATS is estimated to be approximately $975 million.

As of September 1, 2012, Albright, Armstrong, Bay Shore Units 2-4, Eastlake Units 4-5, R. Paul Smith, Rivesville and Willow Island have been deactivated. On April 25, 2012, PJM concluded its initial analysis of the reliability impacts from the previously announced plant deactivations and requested RMR arrangements for Eastlake Units 1-3, Ashtabula Unit 5 and Lake Shore Unit 18 through the spring of 2015. During the year ended December 31, 2012, FirstEnergy recognized pre-tax severance expense of approximately $14 million ($10 million by FES) as a result of deactivations. These costs are included in "other operating expenses" in the Consolidated Statements of Income.

FirstEnergy has various long-term coal transportation agreements, some of which run through 2025 and certain of which are related to the plants described above. Penalties for delivery shortfalls for 2012 under those agreements are approximately $60 million unless, as we believe, those delivery shortfalls are excused by the force majeure provisions of those agreements. However, if we fail to reach a resolution with the counterparties and were it ultimately determined that the force majeure provisions do not excuse those delivery shortfalls, our results of operations and financial condition could be materially adversely impacted.

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 NSR pre-construction permits would be required including an emissions applicability threshold of 75,000 tons per year of CO_2 equivalents 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, South 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.

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 U.S. 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 to reduce fish impingement to a 12% annual average and determine site-specific controls, if any, to reduce entrainment of aquatic life following studies to be provided to permitting authorities. In July 2012, the period for finalizing the Section 316(b) regulation was extended to July 27, 2013. 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 FG 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 January 10, 2013, EPA posted for a 30-day public comment period executed Consent Agreements and unexecuted Final Orders requiring payment of a $125,000 civil penalty and the transfer of 195 acres of wetlands to a nature conservancy to resolve potential liabilities for the three petroleum spills at the Edgewater, Lakeshore and Bay Shore plants. Following consideration of public comments, EPA will take action on the Final Orders.

In October 2009, the WVDEP issued an NPDES water discharge permit for the Fort Martin Plant, which imposes TDS, sulfate concentrations and other effluent limitations for heavy metals, as well as temperature limitations. Concurrent with the issuance of the Fort Martin NPDES permit, WVDEP also issued an administrative order setting deadlines for MP to meet certain of the effluent limits that were effective immediately under the terms of the NPDES permit. MP appealed, and a stay of certain conditions of the NPDES permit and order have been granted pending a final decision on the appeal and subject to WVDEP moving to dissolve the stay. The Fort Martin NPDES permit could require an initial capital investment in excess of $150 million in order to install technology to meet the TDS and sulfate limits, which technology may also meet certain of the other effluent limits. Additional technology may be needed to meet certain other limits in the Fort Martin NPDES 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.

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, AE Supply 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 May 2011, the West Virginia Highlands Conservancy, the West Virginia Rivers Coalition, and the Sierra Club filed a CWA citizen suit in the U.S. District Court for the Northern District of West Virginia 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. 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. MP filed an answer on July 11, 2011, and a motion to stay the proceedings on July 13, 2011. In April 2012, the parties reached a settlement to resolve these CWA citizen suit claims for an immaterial amount. On August 14, 2012, a Consent Decree was entered by the Court resolving these claims. MP is currently seeking relief from the arsenic limits through a WVDEP agency review.

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.

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 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. On July 27, 2012, the PA DEP filed a complaint against FG in the U.S. District Court for the Western District of Pennsylvania with claims under the Resource Conservation and Recovery Act and Pennsylvania's Solid Waste Management Act regarding the LBR CCB Impoundment and simultaneously proposed a Consent Decree between PA DEP and FG to resolve those claims. On December 14, 2012, a modified Consent Decree that addresses public comments received by PA DEP was entered by the court, requiring FG to conduct monitoring, studies and submit a closure plan to the PA DEP, no later than March 31, 2013, and discontinue disposal to LBR as currently permitted by December 31, 2016. The modified Consent Decree also requires payment of civil penalties of $800,000 to resolve claims under the Solid Waste Management Act. On January 23, 2013, FG announced a plan to ship the CCBs from the Bruce Mansfield Plant to the LaBelle coal mine reclamation project. On February 1, 2013, FG submitted a Feasibility Study analyzing various technical issues relevant to the closure of LBR. The Feasibility Study estimated that viable options for placing a final cap over LBR would require between 6 to 16 years with an estimated cost ranging from $78 million to $224 million. The Bruce Mansfield Plant is pursuing several options for its CCBs following December 31, 2016, including beneficial use of CCBs for mine reclamation in LaBelle, Pennsylvania. On December 20, 2012, the Environmental Integrity Project and others served FG with a citizen suit notice alleging CWA and PA Clean Streams Law Violations at LBR. At least 60 days must pass before a complaint can be filed.

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.

Certain of FirstEnergy's utilities have been named as potentially responsible parties at waste disposal sites, which may require cleanup under the CERCLA. 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, 2012, based on estimates of the total costs of cleanup, FE's and its subsidiaries' proportionate responsibility for such costs and the financial ability of other unaffiliated entities to pay. Total liabilities of approximately $124 million (including $88 million applicable to JCP&L) have been accrued through December 31, 2012. Included in the total are accrued liabilities of approximately $81 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. FirstEnergy or its subsidiaries could be found potentially responsible for additional amounts or additional sites, but the possible losses or range of losses cannot be determined or reasonably estimated at this time.

OTHER LEGAL PROCEEDINGS

Nuclear Plant Matters

Under NRC regulations, FirstEnergy must ensure that adequate funds will be available to decommission its nuclear facilities. As of December 31, 2012, FirstEnergy had approximately $2.2 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 guaranty, 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. FirstEnergy currently maintains a $95 million parental guaranty in support of the decommissioning of nuclear facilities which is expected to increase to approximately $135 million in 2013. In December 2012, FirstEnergy Corp. entered into an additional $11 million parental guaranty in support of the decommissioning of the spent fuel storage facilities located at its Davis-Besse and Perry nuclear facilities.

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. 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. 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 sub-surface hairline cracks in the upper portion of the shield building and in the vicinity of the main steam line penetrations. A team of industry-recognized structural concrete experts and Davis-Besse engineers 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. On December 6, 2011, the Davis-Besse plant returned to service. By a letter dated November 7, 2012, the NRC concluded that FENOC satisfied all of the commitments contained in the CAL related to Davis-Besse Shield Building. FENOC continues to monitor the status of the Shield Building.

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. An NRC ASLB granted a hearing on the Davis-Besse license renewal application to a group of petitioners. The NRC subsequently narrowed the scope of admitted contentions in this proceeding to a challenge to the computer code used to model source terms in FENOC's SAMA analysis. On December 28, 2012, the ASLB issued two decisions that granted FENOC's motion for summary dismissal of the remaining SAMA contention and denied the Intervenors' request for a new contention on the

Davis-Besse Shield Building. The ASLB declined to terminate the adjudication. In an earlier order dated August 7, 2012, the NRC stated that it will not issue final licensing decisions until it has appropriately addressed the challenges to the NRC Waste Confidence Decision and Temporary Storage Rule and all pending contentions on this topic should be held in abeyance until further order. In a September 6, 2012, staff requirements memorandum, the NRC directed the staff to publish a final rule and EIS to support an updated Waste Confidence Decision and temporary storage rule within 24 months. The ASLB has suspended further consideration of the Intervenors' proposed contention on the environmental impacts of spent fuel storage in the Davis-Besse license renewal proceeding.

By a 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 conducted several supplemental inspections, including an inspection using Inspection Procedure 95002 to determine if the root cause and contributing causes of risk significant performance issues were understood, the extent of condition was identified, whether safety culture contributed to the performance issues, and if FENOC's corrective actions are sufficient to address the causes and prevent recurrence. On December 28, 2012, the NRC issued a report on the 95002 Inspection that concluded that FENOC "did not provide assurance that the corrective actions for performance issues associated with the Occupational Exposure Control Effectiveness PI were sufficient to address the root and contributing causes and prevent recurrence." Moreover, the NRC also concluded that FENOC "did not adequately address corrective actions for the White NOV." As a result, the NRC will hold open both a parallel PI inspection finding on the occupational exposure issues and the White finding. The NRC will conduct a future inspection to verify the effectiveness of FENOC's corrective actions. Additional adverse findings by the NRC could result in additional NRC oversight and further inspection activities.

By a letter dated January 17, 2013, the NRC notified FENOC that the Perry plant would remain in Column 3 of the action matrix for the NRC reactor oversight process. It stated that although “Perry meets the definition in Inspection Manual Chapter 0305 for Multiple/Repetitive Degraded Cornerstone, Column 4, of the Action Matrix,” current performance issues are well understood and appear to be limited to occupational radiation safety, at present and thus the regulatory actions specified for Column 3 of the Action Matrix are more appropriate. The NRC also noted that Perry would move to Column 4 if: (1) the follow-up 95002 inspection, scheduled for completion in the May-July 2013 timeframe, identifies a significant weakness in Perry's performance; (2) Perry is unable to complete corrective actions necessary to permit the follow-up 95002 inspection to be completed before the end of July 2013; or (3) if another Greater-than-Green PI or finding is identified (other than a change of color for the current Occupational Exposure Control Effectiveness PI issue). Additional adverse findings by the NRC could result in further inspection activities and/or other regulatory actions.

On March 12, 2012, the NRC issued orders requiring safety enhancements at U.S. reactors based on recommendations from the lessons learned Task Force review of the accident at Japan's Fukushima Daiichi nuclear power plant. These orders require additional mitigation strategies for beyond-design-basis external events, and enhanced equipment for monitoring water levels in spent fuel pools. The NRC also requested that licensees including FENOC: re-analyze earthquake and flooding risks using the latest information available; conduct earthquake and flooding hazard walkdowns at their nuclear plants; assess the ability of current communications systems and equipment to perform under a prolonged loss of onsite and offsite electrical power; and assess plant staffing levels needed to fill emergency positions. These and other NRC requirements adopted as a result of the accident at Fukushima Daiichi are likely to result in additional material costs from plant modifications and upgrades at FENOC's nuclear facilities.

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 higher burn up 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 and that the NRC might consider imposing restrictions on reactor operating limits. On March 16, 2012, FENOC submitted its response to the NRC demonstrating that the NRC requirements are being met. After a detailed review of FENOC's submittal and in a January 25, 2013 evaluation, the NRC confirmed the FENOC's evaluation model remains adequate and determined that the schedule for re-analysis was acceptable. The plant remains compliant with regulations regarding fuel parameters. FENOC also agreed to submit to the NRC revised large break loss of coolant accident analyses by December 15, 2016, that further consider the effects of fuel pellet thermal conductivity degradation.

ICG Litigation

On December 28, 2006, AE Supply and MP filed a complaint in the Court of Common Pleas of Allegheny County, Pennsylvania against ICG, Anker WV, and Anker Coal. Anker WV entered into a long term Coal Sales Agreement with AE Supply and MP for the supply of coal to the Harrison generating facility. Prior to the time of trial, ICG was dismissed as a defendant by the Court, which issue can be the subject of a future appeal. As a result of defendants' past and continued failure to supply the contracted coal, AE Supply and MP have incurred and will continue to incur significant additional costs for purchasing replacement coal. A non-jury trial was held from January 10, 2011 through February 1, 2011. At trial, AE Supply and MP presented evidence that they have incurred in excess of $80 million in damages for replacement coal purchased through the end of 2010 and will incur additional damages in excess of $150 million for future shortfalls. Defendants primarily claim that their performance is excused under a force majeure clause in the coal sales agreement and presented evidence at trial that they will continue to not provide the contracted yearly tonnage amounts. On May 2, 2011, the court entered a verdict in favor of AE Supply and MP for $104 million ($90 million in future damages and $14 million for replacement coal / interest). On August 25, 2011, the Allegheny County Court denied all Motions for Post-Trial relief and the May 2, 2011 verdict became final. On August 26, 2011, the defendants posted bond and filed a Notice of Appeal with the Superior Court. On August 13, 2012, the Superior Court affirmed the $14 million past damages award but vacated the $90 million future damages award. While the Superior Court found that the defendants still owed future damages, it remanded the calculation of those damages back to the trial court. The specific amount of those future damages is not known at this time, but they are expected to be calculated at a market price of coal that is significantly lower than the price used by the trial court. On August 27, 2012, AE Supply and MP filed an Application for Reargument En Banc with the Superior Court, which was denied on October 19, 2012. AE Supply and MP filed a Petition for Allowance of Appeal with the Pennsylvania Supreme Court on November 19, 2012. A ruling by the Supreme Court on whether it will hear the case is expected in the second quarter of 2013. AE Supply and MP intend to vigorously pursue this matter through appeal.

Other Legal Matters

In February 2010, a class action lawsuit was filed in Geauga County Court of Common Pleas against FirstEnergy, CEI and OE seeking declaratory judgment and injunctive relief, and compensatory, incidental and consequential damages, related to the reduction of a discount that had previously been in place for residential customers with electric heating, electric water heating, or load management systems. The reduction in the discount had been approved by the PUCO. The court granted the defendant companies' motion to dismiss which was affirmed on appeal on all counts except for one relating to an allegation of fraud which was remanded to the trial court. The defendant companies appealed to the Supreme Court of Ohio on December 5, 2011, challenging this one aspect of the case. The Supreme Court of Ohio found in favor of the defendant companies on November 28, 2012, ruling that jurisdiction on the issue raised resides with the PUCO, not civil court.

On July 13, 2010, a lawsuit was filed in Allegheny County Court of Common Pleas by Michael Goretzka, for wrongful death, negligence, and negligent infliction of emotional distress claims. Plaintiff's decedent, Carrie Goretzka, was fatally electrocuted when she contacted a downed power line at her residence in Irwin, Pennsylvania. The trial resulted in a verdict against WP for $48 million in compensatory damages and $61 million in punitive damages. The parties have settled this matter and WP's portion of the settlement will be covered by insurance subject to the remainder of its deductible. On May 30, 2012, the PPUC's Bureau of Investigation and Enforcement (I&E) filed a Formal Complaint at the PPUC regarding this matter. On February 13, 2013, WP and I&E filed a Joint Petition for Full Settlement that includes, among other things, WP's agreement to conduct an infrared inspection of its primary distribution system, modify certain training programs, and pay an $86,000 civil penalty. The settlement is subject to PPUC approval.

There are various lawsuits, claims (including claims for asbestos exposure) and proceedings related to FirstEnergy's normal business operations pending against FirstEnergy and its subsidiaries. The other potentially material items not otherwise discussed above are described under Note 14, Regulatory Matters of the Combined Notes to Consolidated Financial Statements.

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

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

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

Revenue Recognition

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

Regulatory Accounting

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

Pensions and OPEB Accounting

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

FirstEnergy provides some non-contributory pre-retirement basic life insurance for employees who are eligible to retire. Health care benefits and/or subsidies to purchase health insurance, which include certain employee contributions, deductibles and co-payments, may also be available upon retirement to certain employees, their dependents and, under certain circumstances, their survivors. FirstEnergy also has obligations to former or inactive employees after employment, but before retirement, for disability-related benefits.

FirstEnergy's pensions and OPEB funding policy is based on actuarial computations using the projected unit credit method. During the year ended December 31, 2012, FirstEnergy made a voluntary $600 million contribution to its qualified pension plan. The underfunded status of FirstEnergy's qualified and non-qualified pension and OPEB plans as of December 31, 2012 was $2.9 billion.

In selecting an assumed discount rate, FirstEnergy considers currently available rates of return on high-quality fixed income investments expected to be available during the period to maturity of the pension and OPEB obligations. The assumed discount rates for pensions were 4.25%, 5.00% and 5.50% as of December 31, 2012, 2011 and 2010, respectively. The assumed discount rates for OPEB were 4.00%, 4.75% and 5.00% as of December 31, 2012, 2011 and 2010, respectively.

FirstEnergy's assumed rate of return on pension plan assets considers historical market returns and economic forecasts for the types of investments held by the pension trusts. In 2012, FirstEnergy's qualified pensions and OPEB plan assets earned $660 million or 9.2% compared to amounts earned of $387 million, or 6.05% in 2011. The qualified pension and OPEB costs in 2012 and 2011 were computed using an assumed 7.75% and 8.25% rate of return, respectively, on plan assets which generated $523 million and $486 million of expected returns on plan assets, respectively. The expected return on pensions and OPEB assets is based on the trusts' asset allocation targets and the historical performance of risk-based and fixed income securities. The gains or losses generated as a result of the difference between expected and actual returns on plan assets will increase or decrease future net periodic pension and OPEB cost as the difference is recognized annually in the fourth quarter of each fiscal year.

Based on discounts rates of 4.25% for pension, 4.00% for OPEB and an estimated return on assets of 7.75%, FirstEnergy expects its 2013 pre-tax net periodic postemployment benefit credits (including amounts capitalized) to be approximately $105 million (excluding any actuarial mark-to-market adjustments that would be recognized in 2013).

The following table reflects the portion of pensions and OPEB costs that were charged to expense in the three years ended December 31, 2012.

Postemployment Benefits Expense (Credits)	2012	2011	2010
	(In millions)		
Pensions	$596	$555	$247
OPEB	(34)	(112)	(126)
Total	$562	$443	$121

Health care cost trends continue to increase and will affect future OPEB costs. The 2012 composite health care trend rate assumptions were approximately 7.5-8.0%, compared to 7.5-8.5% in 2011, gradually decreasing to 5% in later years. In determining FirstEnergy's trend rate assumptions, included are the specific provisions of FirstEnergy's health care plans, the demographics and utilization rates of plan participants, actual cost increases experienced in FirstEnergy's health care plans, and projections of future medical trend rates. The effect on the pension and OPEB costs from changes in key assumptions are as follows:

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

Assumption	Adverse Change	Pensions	OPEB	Total
			(In millions)	
Discount rate	Decrease by .25%	$274	$20	$294
Long-term return on assets	Decrease by .25%	$16	$1	$17
Health care trend rate	Increase by 1.0%	N/A	$30	$30

Long-Lived Assets

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

Asset Retirement Obligations

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

Income Taxes

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

FirstEnergy accounts for uncertainty in income taxes recognized in its financial statements. We account for uncertain income tax positions using a benefit recognition model with a two-step approach, a more-likely-than-not recognition criterion and a measurement attribute that measures the position as the largest amount of tax benefit that is greater than 50% likely of being ultimately realized upon settlement. If it is not more likely than not that the benefit will be sustained on its technical merits, no benefit will be recorded. Uncertain tax positions that relate only to timing of when an item is included on a tax return are considered to have met the recognition threshold. The Company recognizes interest expense or income related to uncertain tax positions. That amount is computed by applying the applicable statutory interest rate to the difference between the tax position recognized and the amount previously taken or expected to be taken on the tax return. FirstEnergy includes net interest and penalties in the provision for income taxes.

Goodwill

In a business combination, the excess of the purchase price over the estimated fair values of the assets acquired and liabilities assumed is recognized as goodwill. Goodwill is evaluated for impairment at least annually and more frequently if indicators of impairment arise. In evaluating goodwill for impairment, FirstEnergy first assesses qualitative factors to determine whether it is more likely than not (that is, likelihood of more than 50 percent) that the fair value of a reporting unit is less than its carrying value (including goodwill). If FirstEnergy concludes that it is not more likely than not that the fair value of a reporting unit is less than its carrying value, then no further testing is required. However, if FirstEnergy concludes that it is more likely than not that the fair value of a reporting unit is less than its carrying value, then the two-step goodwill impairment test is performed to identify potential goodwill impairment and measure the amount of goodwill impaired to be recognized, if any.

NEW ACCOUNTING PRONOUNCEMENTS

New accounting pronouncements not yet effective are not expected to have a material effect on the financial statements of FE or its subsidiaries.

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

FES is a wholly owned subsidiary of FirstEnergy. FES provides energy-related products and services to retail and wholesale customers, and through its principal subsidiaries, FG and NG, owns or leases, operates and maintains FirstEnergy's fossil and hydroelectric generation facilities (excluding the Allegheny facilities), and owns, through its subsidiary, NG, FirstEnergy's nuclear generation facilities. FENOC, a wholly owned subsidiary of FirstEnergy, operates and maintains the nuclear generating facilities. FES purchases the entire output of the generation facilities owned by FG and NG, and may purchase the uncommitted output of AE Supply, 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, and pursuant to full output, cost-of-service PSAs.

FES' revenues are derived primarily from sales to individual retail customers, sales to customers in the form of governmental aggregation programs, and participation in affiliated and non-affiliated POLR auctions. FES' sales are primarily concentrated in Ohio, Pennsylvania, Illinois, Michigan, New Jersey and Maryland. The demand for electricity produced and sold by FES, along with the price of that electricity, is principally impacted by conditions in competitive power markets, global economic activity as well as economic activity and weather conditions in the Midwest and Mid-Atlantic regions of the United States.

FES is exposed to various market and financial risks, including the risk of price fluctuations in the wholesale power markets. Wholesale power prices may be impacted by the prices of other commodities, including coal and natural gas, and energy efficiency and demand response programs, as well as regulatory and legislative actions, such as MATS among other factors. FES attempts to mitigate the market risk inherent in its energy position by economically hedging its exposure and continuously monitoring various risk measurement metrics to ensure compliance with its risk management policies.

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

Results of Operations

Net income increased by $246 million in 2012 compared to 2011, as more fully described below.

Revenues -

Total revenues increased $441 million, or 8%, in 2012, compared to 2011, primarily due to growth in direct and governmental aggregation sales and wholesale revenue, partially offset by a decline in POLR sales and the sale of RECs. Revenues were adversely impacted by lower unit prices compared to 2011.

The increase in total revenues resulted from the following sources:

Revenues by Type of Service	For the Years Ended December 31, 2012	2011	Increase (Decrease)
	(In millions)		
Direct and Governmental Aggregation	$4,230	$3,785	$445
POLR and Structured	899	944	(45)
Wholesale	535	457	78
Transmission	120	108	12
RECs	7	67	(60)
Other	127	116	11
Total Revenues	$5,918	$5,477	$441

MWH Sales by Channel	For the Years Ended December 31, 2012	2011	Increase (Decrease)
	(In thousands)		
Direct	53,099	46,187	15.0 %
Governmental Aggregation	22,499	17,722	27.0 %
POLR and Structured	16,212	15,340	5.7 %
Wholesale	96	2,916	(96.7)%
Total MWH Sales	91,906	82,165	11.9 %

The increase in direct and governmental aggregation revenues of $445 million resulted from the acquisition of new residential, commercial and industrial customers. Sales were provided to approximately 2.6 million customers as of December 2012, compared to approximately 1.8 million at the end of 2011. The volume increase was partially offset by lower unit prices for commercial, industrial and governmental aggregation customers.

The decrease in POLR and structured revenues of $45 million was due primarily to lower unit prices, which were partially offset by increased sales volumes.

Wholesale revenues increased $78 million due to increased gains of $276 million on financially settled contracts, partially offset by a $91 million decrease in short-term (net hourly position) transactions and a $107 million decrease in capacity revenues resulting from lower capacity prices.

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

Source of Change in Direct and Governmental Aggregation	Increase (Decrease)
	(In millions)
Effect of increase in sales volumes	$705
Change in prices	(260)
	$445

Source of Change in POLR and Structured Revenues	Increase (Decrease)
	(In millions)
Effect of increase in sales volumes	$16
Change in prices	(61)
	$(45)

Source of Change in Wholesale Revenues	Increase (Decrease)
	(In millions)
Effect of decrease in sales volumes	$(90)
Change in prices	(1)
Gain on settled contracts	276
Capacity revenue	(107)
	$78

Operating Expenses -

Total operating expenses increased by $99 million in 2012 compared to 2011.

The following table summarizes the factors contributing to the changes in fuel and purchased power costs in 2012 compared with 2011:

Source of Change in Fuel and Purchased Power	Increase (Decrease) (In millions)
Fossil Fuel:	
Change due to increased unit costs	$117
Change due to volume consumed	(189)
	(72)
Nuclear Fuel:	
Change due to increased unit costs	2
Change due to volume consumed	13
	15
Non-affiliated Purchased Power:	
Change due to decreased unit costs	(310)
Change due to volume purchased	729
Loss on settled contracts	200
Capacity expense	(116)
	503
Affiliated Purchased Power:	
Change due to increased unit costs	195
Change due to volume purchased	14
	209
Net Increase in Fuel and Purchased Power Costs	$655

Fuel costs decreased $57 million primarily due to lower volumes as a result of the deactivation of fossil generating units, the temporary reduction in operations at the Sammis Plant in September 2012, and an increase in economic purchases, partially offset by higher unit prices. Higher unit prices resulted primarily from a $50 million charge associated with the termination of a coal contract that is no longer needed as a result of the plant deactivations.

The increase in non-affiliated purchased power volumes primarily relates to the overall increase in sales volumes, economic purchases and lower generation resulting from the deactivation of fossil generating units, the temporary reduction in operations at Sammis and a $200 million loss on settled contracts. Affiliated purchased power unit costs increased primarily due to a $192 million affiliated company power sales agreement between FES and AE Supply.

Other operating expenses decreased by $270 million in 2012, compared to 2011 due to the following:

- Transmission expenses decreased $75 million due primarily to lower congestion, network and line loss costs, partially offset by higher ancillary costs.
- Nuclear operating costs decreased by $13 million due primarily to lower contractor, materials and equipment costs, which were partially offset by higher labor costs. In 2012, there were refueling outages at Davis Besse and Beaver Valley Units 1 and 2. There were refueling outages at Perry and Beaver Valley Unit 2 during 2011. Total MW days were reduced slightly in 2012 compared to 2011.
- Fossil operating costs decreased by $44 million due primarily to lower contractor, materials and equipment costs resulting from a decrease in planned and unplanned generating unit outages.
- Other operating expenses decreased by $138 million primarily due to favorable mark-to-market adjustments on commodity contract positions ($123 million). In addition, 2011 expenses included a $54 million provision for excess and obsolete material relating to revised inventory practices adopted in connection with the Allegheny merger. These decreases were partially offset by increases of $39 million for labor, agent fees, and costs associated with the retail business.

Impairment charges on long-lived assets decreased by $294 million primarily due to 2011 charges related to the decision to deactivate certain coal fired generating units.

General taxes increased by $12 million due to an increase in revenue-related taxes. Pensions and OPEB mark-to-market adjustment charges declined $5 million from lower net actuarial losses.

Other Expense -
Total other expense decreased by $26 million in 2012, compared to 2011, primarily due to lower net interest expense of $12 million resulting from debt reductions in 2011 and credits related to a settlement with the DOE. Non-operating income increased by $14 million due primarily to additional proceeds on 2011 asset sales that were earned during 2012.

Market Risk Information

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

Commodity Price Risk

FES is exposed to financial risks resulting from fluctuating interest rates and commodity prices, including prices for electricity, natural gas, coal and energy transmission. FirstEnergy's Risk Policy Committee is responsible for promoting the effective design and implementation of sound risk management programs and oversees compliance with corporate risk management policies and established risk management practice. FES uses a variety of derivative instruments for risk management purposes including forward contracts, options, futures contracts and swaps.

Sources of information for the valuation of commodity derivative contract assets and liabilities as of December 31, 2012, are summarized by year in the following table:

Source of Information-Fair Value by Contract Year	2013	2014	2015	2016	2017	Thereafter	Total
	(In millions)						
Prices actively quoted[1]	$(3)	$—	$—	$—	$—	$—	$(3)
Other external sources[2]	37	43	10	7	—	—	97
Prices based on models	(1)	—	—	—	3	1	3
Total	$33	$43	$10	$7	$3	$1	$97

(1) Represents exchange traded New York Mercantile Exchange futures and options.
(2) Primarily represents contracts based on broker and ICE quotes.

FES performs sensitivity analyses to estimate its exposure to the market risk of its commodity positions. Based on derivative contracts held as of December 31, 2012, a decrease of 10% in commodity prices would decrease net income by approximately $3 million during the next 12 months.

Interest Rate Risk

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

Comparison of Carrying Value to Fair Value

Year of Maturity	2013	2014	2015	2016	2017	There-after	Total	Fair Value
	(In millions)							
Assets:								
Investments Other Than Cash and Cash Equivalents:								
Fixed Income						$792	$792	$792
Average interest rate						5.3%	5.3%	
Liabilities:								
Long-term Debt:								
Fixed rate	$127	$160	$502	$37	$30	$2,602	$3,458	$3,788
Average interest rate	8.6%	7.6%	5.4%	7.9%	2.5%	4.9%	5.2%	
Variable rate						$736	$736	$736
Average interest rate						0.1%	0.1%	

Equity Price Risk

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NDT funds have been established to satisfy NG's nuclear decommissioning obligations. Included in FES's NDT are fixed income, equities and short-term investments carried at market values of approximately $792 million, $294 million and $103 million, respectively, as of December 31, 2012, excluding $94 million of net receivables, payables and accrued income. A hypothetical 10% decrease in prices quoted by stock exchanges would result in a $29 million reduction in fair value as of December 31, 2012. NG recognizes in earnings the unrealized losses on available-for-sale securities held in its NDT as OTTI. A decline in the value of FES's NDT or a significant escalation in estimated decommissioning costs could result in additional funding requirements.

Credit Risk

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

Wholesale Credit Risk

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

Retail Credit Risk

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

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

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

OHIO EDISON COMPANY

MANAGEMENT'S NARRATIVE
ANALYSIS OF RESULTS OF OPERATIONS

OE is a wholly owned electric utility subsidiary of FE. OE engages in the distribution and sale of electric energy to customers in a 7,000 square mile area of central and northeastern Ohio and, through its wholly owned subsidiary, Penn, 1,100 square miles in western Pennsylvania. OE and Penn provide regulated electric distribution services for their customers as well as generation procurement services for customers who have not selected an alternative supplier. The areas served by OE and Penn have populations of approximately 2.3 million and 0.4 million, respectively.

For additional information with respect to OE, please see the information contained in FE's Management's Discussion and Analysis of Financial Condition and Results of Operations under the following subheadings, which information is incorporated by reference herein: Overview, Results of Operations - Regulatory Assets, Capital Resources and Liquidity, Market Risk Information, Credit Risk and Outlook.

On January 30, 2013, OE filed a Form 15 with the SEC to deregister its securities and suspend its obligation to file periodic reports under the Securities Exchange Act of 1934, as amended, except that the registrant has filed this Annual Report on Form 10-K for the year ended December 31, 2012. This Annual Report on Form 10-K will be the last filing made by OE with the SEC under the Exchange Act.

Results of Operations

Net income decreased by $27 million during 2012, compared to 2011, as more fully described below.

Revenues -

Revenues decreased by $18 million in 2012, compared with 2011, due to a decrease in retail generation revenues, partially offset by an increase in distribution revenues.

Distribution revenues increased by $27 million in 2012, compared to 2011. Average prices for all customer classes increased due to the implementation of Ohio's rider NMB in June 2011, which recovers NMB charges from PJM, including network integration TSCs, partially offset by the suspension of Ohio's deferred cost recovery rider in December 2011. These increases were partially offset by reduced MWH deliveries driven by lower weather-related usage and declining average customer consumption.

Changes in distribution MWH deliveries and revenues in 2012, compared to 2011, are summarized in the following tables:

	For the Years Ended December 31,		
Distribution MWH Deliveries	2012	2011	Decrease
Residential	11,068	11,223	(1.4)%
Commercial	8,025	8,053	(0.4)%
Industrial	9,664	9,813	(1.5)%
Other	148	152	(2.9)%
Decrease in Distribution MWH Deliveries	28,905	29,241	(1.2)%

	For the Years Ended December 31,		Increase
Distribution Revenues (in millions)	2012	2011	(Decrease) (In millions)
Residential	$542	$533	$9
Commercial	245	233	12
Industrial	87	80	7
Other	9	10	(1)
Net Increase in Distribution Revenues	$883	$856	$27

Retail generation revenues are attributable to non-shopping customers and are satisfied by generation procured through full-requirements auctions. OE and Penn defer the difference between retail generation revenues and purchased power costs, resulting in no material effect to current period earnings. Retail generation revenues decreased by $59 million primarily due to increased customer shopping, partially offset by higher average prices in the residential customer class. Lower MWH sales were primarily due to declining average customer consumption, reduced residential accounts as well as an increase in customer shopping levels to 74% compared to 71% in 2011. This increased customer shopping, which does not materially affect earnings, is expected to continue. Higher average prices for residential customers were primarily due to the recovery of residential generation credits for electric heating discounts, which began in September 2011.

Changes in retail generation MWH sales and revenues in 2012, compared to 2011, are summarized in the following tables:

	For the Years Ended December 31,		
Retail Generation MWH Sales	2012	2011	Decrease
Residential	4,416	4,975	(11.2)%
Commercial	1,240	1,639	(24.4)%
Industrial	1,711	1,814	(5.7)%
Other	142	151	(5.9)%
Decrease in Retail Generation Sales	7,509	8,579	(12.5)%

	For the Years Ended December 31,		Increase
Retail Generation Revenues (in million)	2012	2011	(Decrease)
			(In millions)
Residential	$296	$293	$3
Commercial	96	141	(45)
Industrial	98	115	(17)
Other	5	5	—
Net Decrease in Retail Generation Revenues	$495	$554	$(59)

Wholesale generation revenues increased by $9 million in 2012, compared to 2011, due to higher revenues from sales to NG from OE's leasehold interests in Perry Unit 1 and Beaver Valley Unit 2.

Operating Expenses -

Total operating expenses increased by $13 million in 2012, compared to 2011. The following table presents changes from the prior period by expense category:

Operating Expenses - Changes	Increase (Decrease)
	(In millions)
Purchased power costs	$(126)
Other operating expenses	40
Pensions and OPEB mark-to-market adjustment	41
Provision for depreciation	8
Amortization of regulatory assets, net	47
General taxes	3
Net Increase in Operating Expenses	$13

Purchased power costs decreased in 2012, compared to 2011, due to lower MWH purchases resulting from reduced requirements from lower generation sales and lower unit costs. The increase in other operating expenses for 2012 compared to 2011, was principally due to expenses associated with network integration TSCs that, prior to June 2011, were incurred by generation suppliers, and are being recovered through the Rider NMB discussed above. Increased pensions and OPEB mark-to-market adjustment charges were due to higher net actuarial losses in 2012 as compared to 2011. Amortization of regulatory assets, net, increased primarily due to lower deferred residential generation credits in 2012. Provision for depreciation expense increased mainly due to an increase in the depreciable asset base. General taxes increased due to an increase in property taxes.

Interest Rate Risk

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

Comparison of Carrying Value to Fair Value

Year of Maturity	2013	2014	2015	2016	2017	There-after	Total	Fair Value
	(In millions)							
Assets:								
Investments Other Than Cash and Cash Equivalents:								
Fixed Income	$37	$42	$37	$13	$3	$137	$269	$285
Average interest rate	8.8 %	8.8 %	8.9 %	8.9 %	8.9 %	0.2 %	4.5 %	
Liabilities:								
Long-term Debt:								
Fixed rate	$1	$1	$151	$251	$1	$752	$1,157	$1,500
Average interest rate	9.7 %	9.7 %	5.5 %	6.4 %	9.7 %	7.3 %	6.9 %	

Equity Price Risk

NDT funds have been established to satisfy nuclear decommissioning obligations. Included in OE’s NDT are fixed income and short-term investments carried at market values of approximately $137 million and $3 million, respectively, as of December 31, 2012, excluding $1 million of net receivables, payables and accrued income. OE recognizes in earnings the unrealized losses on available-for-sale securities held in its NDT as OTTI. A decline in the value of OE's NDT or a significant escalation in estimated decommissioning costs could result in additional funding requirements.

Credit Risk

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

JERSEY CENTRAL POWER & LIGHT COMPANY

MANAGEMENT'S NARRATIVE
ANALYSIS OF RESULTS OF OPERATIONS

JCP&L is a wholly owned, electric utility subsidiary of FE. JCP&L conducts business in New Jersey by providing regulated electric transmission and distribution services in 3,200 square miles of northern, western and east central New Jersey. The area it serves has a population of approximately 2.7 million. JCP&L also has an ownership interest in a hydroelectric generating facility. JCP&L procures electric supply to serve its BGS customers through a statewide auction process approved by the NJBPU.

For additional information with respect to JCP&L, please see the information contained in FE's Management's Discussion and Analysis of Financial Condition and Results of Operations under the following subheadings, which information is incorporated by reference herein: Overview, Results of Operations - Regulatory Assets, Capital Resources and Liquidity, Market Risk Information, Credit Risk and Outlook.

On January 30, 2013, JCP&L filed a Form 15 with the SEC to deregister its securities and suspend its obligation to file periodic reports under the Securities Exchange Act of 1934, as amended, except that the registrant has filed this Annual Report on Form 10-K for the year ended December 31, 2012. This Annual Report on Form 10-K will be the last filing made by JCP&L with the SEC under the Exchange Act.

Results of Operations

Net income decreased by $11 million in 2012, compared to 2011, as more fully described below.

Revenues -

Revenues decreased by $468 million, or 19%, in 2012, compared to 2011. The decrease in revenues was due to lower distribution, retail generation and wholesale generation revenues.

Distribution revenues decreased by $149 million in 2012, compared to 2011, primarily due to lower MWH deliveries to all customer classes and the completion of the NJBPU-approved NUG deferred cost recovery. Reduced MWH deliveries to residential and commercial customers reflect decreased weather-related usage in 2012.

Changes in distribution MWH deliveries and revenues in 2012 compared to 2011 are summarized in the following tables:

	For the Years Ended December 31,		
Distribution MWH Deliveries	2012	2011	Decrease
	(In thousands)		
Residential	9,391	9,697	(3.2)%
Commercial	9,015	9,282	(2.9)%
Industrial	2,320	2,413	(3.9)%
Other	87	89	(2.5)%
Decrease in Distribution Deliveries	20,813	21,481	(3.1)%

	For the Years Ended December 31,		
Distribution Revenues	2012	2011	Decrease
	(In millions)		
Residential	$439	$510	$(71)
Commercial	323	385	(62)
Industrial	58	73	(15)
Other	16	17	(1)
Decrease in Distribution Revenues	$836	$985	$(149)

Retail generation obligations are attributable to non-shopping customers and are satisfied by generation procured through full-requirements auctions. JCP&L defers the difference between retail generation revenues and purchased power costs, resulting in no material effect on earnings. Retail generation revenues decreased by $233 million due to lower retail generation MWH sales in all customer classes primarily due to lower weather-related usage and an increase in customer shopping levels to 50% in 2012, compared to 44% in 2011. This increased customer shopping, which does not materially affect earnings, is expected to continue.

Decreases in retail generation MWH sales and revenues in 2012, compared to 2011, are summarized in the following tables:

Retail Generation MWH Sales	For the Years Ended December 31, 2012	2011	Decrease
	(In thousands)		
Residential	7,649	8,560	(10.6)%
Commercial	2,530	3,122	(19.0)%
Industrial	241	297	(18.7)%
Other	54	63	(13.4)%
Decrease in Retail Generation Sales	10,474	12,042	(13.0)%

Retail Generation Revenues	For the Years Ended December 31, 2012	2011	Decrease
	(In millions)		
Residential	$744	$895	$(151)
Commercial	236	309	(73)
Industrial	18	26	(8)
Other	4	5	(1)
Decrease in Retail Generation Revenues	$1,002	$1,235	$(233)

Wholesale generation revenues decreased by $86 million in 2012, compared to 2011, primarily due to a decrease in PJM spot market energy sales, that resulted from the expiration of a NUG contract in August 2011.

Operating Expenses -

Total operating expenses decreased by $453 million in 2012, compared to 2011. The following table presents changes from the prior period by expense category:

Operating Expenses - Changes	Increase (Decrease)
	(In millions)
Purchased power costs	$(313)
Other operating expenses	196
Pensions and OPEB mark-to-market adjustment	5
Provision for depreciation	6
Deferral of storm costs	(187)
Amortization of other regulatory assets, net	(148)
General taxes	(12)
Net Decrease in Operating Expenses	$(453)

Purchased power costs decreased in 2012 due to the expiration of a NUG contract and a decrease in volumes required, as described above. Depreciation expense increased mainly due to an increase in the depreciable asset base. General taxes decreased due to a phase-out of the transitional TEFA tax in New Jersey. In late October 2012, JCP&L experienced unprecedented damage in its service territory, as a result of Hurricane Sandy. Storm costs for JCP&L were approximately $629 million, of which $354 million was capital, $154 million related to asset removal, $121 million related to other operating expense and $268 was deferred for future recovery from customers.

Market Risk Information

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

Commodity Price Risk

JCP&L is exposed to financial risks resulting from fluctuating interest rates and commodity prices, including prices for electricity, natural gas and energy transmission. JCP&L uses a variety of derivative instruments for risk management purposes including

forward contracts, options, futures contracts and swaps. FirstEnergy's Risk Policy Committee is responsible for promoting the effective design and implementation of sound risk management programs and oversees compliance with corporate risk management policies and established risk management practice.

Sources of information for the valuation of commodity derivative contract assets and liabilities as of December 31, 2012, are summarized by year in the following table:

Source of Information- Fair Value by Contract Year	2013	2014	2015	2016	2017	Thereafter	Total
	(In millions)						
Prices actively quoted[1]	$—	$—	$—	$—	$—	$—	$—
Other external sources[2]	(83)	(79)	(45)	(27)	—	—	(234)
Prices based on models	—	—	—	—	(15)	(149)	(164)
Total[3]	$(83)	$(79)	$(45)	$(27)	$(15)	$(149)	$(398)

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

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

(3) Includes $(398) million in non-hedge commodity derivative contracts that are related to NUG and LCAPP contracts. NUG and LCAPP contracts are subject to regulatory accounting and do not materially impact earnings.

JCP&L performs sensitivity analyses to estimate its exposure to the market risk of its commodity positions. Based on derivative contracts held as of December 31, 2012, an increase or decrease of 10% in commodity prices would not have a material effect on JCP&L's net income for the next 12 months.

Interest Rate Risk

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

Comparison of Carrying Value to Fair Value

Year of Maturity	2013	2014	2015	2016	2017	There-after	Total	Fair Value
	(In millions)							
Assets:								
Investments Other Than Cash and Cash Equivalents:								
Fixed Income						$393	$393	$393
Average interest rate						3.6 %	3.6 %	
Liabilities:								
Long-term Debt:								
Fixed rate	$36	$38	$41	$343	$279	$1,006	$1,743	$2,059
Average interest rate	5.7 %	5.9 %	6.0 %	5.7 %	5.7 %	6.3 %	6.1 %	

Equity Price Risk

NDT funds have been established to satisfy nuclear decommissioning obligations. Included in JCP&L's NDT are fixed income and short-term investments carried at market values of approximately $169 million and $29 million, respectively, as of December 31, 2012, excluding $3 million of net receivables, payables and accrued income. JCP&L's NDT is subject to regulatory accounting, with unrealized gains and losses recorded as regulatory assets or liabilities, since the difference between investments held in trust and the decommissioning liabilities are expected to be recovered from or refunded to customers. A decline in the value of JCP&L's NDT or a significant escalation in estimated decommissioning costs could result in additional funding requirements.

Credit Risk

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

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The information required by ITEM 7A relating to market risk is set forth in ITEM 7. Management's Discussion and Analysis of Financial Condition and Results of Operations.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

MANAGEMENT REPORTS

Management's Responsibility for Financial Statements

The consolidated financial statements of FirstEnergy Corp. (Company) were prepared by management, who takes responsibility for their integrity and objectivity. The statements were prepared in conformity with accounting principles generally accepted in the United States and are consistent with other financial information appearing elsewhere in this report. PricewaterhouseCoopers LLP, an independent registered public accounting firm, has expressed an unqualified opinion on the Company's 2012 consolidated financial statements as stated in their audit report included herein.

The Company's internal auditors, who are responsible to the Audit Committee of the Company's Board of Directors, review the results and performance of operating units within the Company for adequacy, effectiveness and reliability of accounting and reporting systems, as well as managerial and operating controls.

The Company's Audit Committee consists of five independent directors whose duties include: consideration of the adequacy of the internal controls of the Company and the objectivity of financial reporting; inquiry into the number, extent, adequacy and validity of regular and special audits conducted by independent auditors and the internal auditors; and reporting to the Board of Directors the Committee's findings and any recommendation for changes in scope, methods or procedures of the auditing functions. The Committee is directly responsible for appointing the Company's independent registered public accounting firm and is charged with reviewing and approving all services performed for the Company by the independent registered public accounting firm and for reviewing and approving the related fees. The Committee reviews the independent registered public accounting firm's report on internal quality control and reviews all relationships between the independent registered public accounting firm and the Company, in order to assess the independent registered public accounting firm's independence. The Committee also reviews management's programs to monitor compliance with the Company's policies on business ethics and risk management. The Committee establishes procedures to receive and respond to complaints received by the Company regarding accounting, internal accounting controls, or auditing matters and allows for the confidential, anonymous submission of concerns by employees. The Audit Committee held nine meetings in 2012.

Management's Report on Internal Control Over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rule 13a-15(f) of the Securities Exchange Act of 1934. Using the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in Internal Control — Integrated Framework, management conducted an evaluation of the effectiveness of the Company's internal control over financial reporting under the supervision of the Chief Executive Officer and the Chief Financial Officer. Based on that evaluation, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2012. The effectiveness of the Company's internal control over financial reporting, as of December 31, 2012, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

MANAGEMENT REPORTS

Management's Responsibility for Financial Statements

The consolidated financial statements of FirstEnergy Solutions Corp. (Company) were prepared by management, who takes responsibility for their integrity and objectivity. The statements were prepared in conformity with accounting principles generally accepted in the United States and are consistent with other financial information appearing elsewhere in this report. PricewaterhouseCoopers LLP, an independent registered public accounting firm, has expressed an unqualified opinion on the Company's 2012 consolidated financial statements as stated in their audit report included herein.

FirstEnergy Corp.'s internal auditors, who are responsible to the Audit Committee of FirstEnergy's Board of Directors, review the results and performance of the Company for adequacy, effectiveness and reliability of accounting and reporting systems, as well as managerial and operating controls.

FirstEnergy's Audit Committee consists of five independent directors whose duties include: consideration of the adequacy of the internal controls of the Company and the objectivity of financial reporting; inquiry into the number, extent, adequacy and validity of regular and special audits conducted by independent auditors and the internal auditors; and reporting to the Board of Directors the Committee's findings and any recommendation for changes in scope, methods or procedures of the auditing functions. The Committee is directly responsible for appointing the Company's independent registered public accounting firm and is charged with reviewing and approving all services performed for the Company by the independent registered public accounting firm and for reviewing and approving the related fees. The Committee reviews the independent registered public accounting firm's report on internal quality control and reviews all relationships between the independent registered public accounting firm and the Company, in order to assess the independent registered public accounting firm's independence. The Committee also reviews management's programs to monitor compliance with the Company's policies on business ethics and risk management. The Committee establishes procedures to receive and respond to complaints received by the Company regarding accounting, internal accounting controls, or auditing matters and allows for the confidential, anonymous submission of concerns by employees. The Audit Committee held nine meetings in 2012.

Management's Report on Internal Control Over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rule 13a-15(f) of the Securities Exchange Act of 1934. Using the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in Internal Control — Integrated Framework, management conducted an evaluation of the effectiveness of the Company's internal control over financial reporting under the supervision of the Chief Executive Officer and the Chief Financial Officer. Based on that evaluation, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2012.

MANAGEMENT REPORTS

Management's Responsibility for Financial Statements

The consolidated financial statements of Ohio Edison Company (Company) were prepared by management, who takes responsibility for their integrity and objectivity. The statements were prepared in conformity with accounting principles generally accepted in the United States and are consistent with other financial information appearing elsewhere in this report. PricewaterhouseCoopers LLP, an independent registered public accounting firm, has expressed an unqualified opinion on the Company's 2012 consolidated financial statements as stated in their audit report included herein.

FirstEnergy Corp.'s internal auditors, who are responsible to the Audit Committee of FirstEnergy's Board of Directors, review the results and performance of the Company for adequacy, effectiveness and reliability of accounting and reporting systems, as well as managerial and operating controls.

FirstEnergy's Audit Committee consists of five independent directors whose duties include: consideration of the adequacy of the internal controls of the Company and the objectivity of financial reporting; inquiry into the number, extent, adequacy and validity of regular and special audits conducted by independent auditors and the internal auditors; and reporting to the Board of Directors the Committee's findings and any recommendation for changes in scope, methods or procedures of the auditing functions. The Committee is directly responsible for appointing the Company's independent registered public accounting firm and is charged with reviewing and approving all services performed for the Company by the independent registered public accounting firm and for reviewing and approving the related fees. The Committee reviews the independent registered public accounting firm's report on internal quality control and reviews all relationships between the independent registered public accounting firm and the Company, in order to assess the independent registered public accounting firm's independence. The Committee also reviews management's programs to monitor compliance with the Company's policies on business ethics and risk management. The Committee establishes procedures to receive and respond to complaints received by the Company regarding accounting, internal accounting controls, or auditing matters and allows for the confidential, anonymous submission of concerns by employees. The Audit Committee held nine meetings in 2012.

Management's Report on Internal Control Over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rule 13a-15(f) of the Securities Exchange Act of 1934. Using the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in Internal Control — Integrated Framework, management conducted an evaluation of the effectiveness of the Company's internal control over financial reporting under the supervision of the Chief Executive Officer and the Chief Financial Officer. Based on that evaluation, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2012.

MANAGEMENT REPORTS

Management's Responsibility for Financial Statements

The consolidated financial statements of Jersey Central Power & Light Company (Company) were prepared by management, who takes responsibility for their integrity and objectivity. The statements were prepared in conformity with accounting principles generally accepted in the United States and are consistent with other financial information appearing elsewhere in this report. PricewaterhouseCoopers LLP, an independent registered public accounting firm, has expressed an unqualified opinion on the Company's 2012 consolidated financial statements as stated in their audit report included herein.

FirstEnergy Corp.'s internal auditors, who are responsible to the Audit Committee of FirstEnergy's Board of Directors, review the results and performance of the Company for adequacy, effectiveness and reliability of accounting and reporting systems, as well as managerial and operating controls.

FirstEnergy's Audit Committee consists of five independent directors whose duties include: consideration of the adequacy of the internal controls of the Company and the objectivity of financial reporting; inquiry into the number, extent, adequacy and validity of regular and special audits conducted by independent auditors and the internal auditors; and reporting to the Board of Directors the Committee's findings and any recommendation for changes in scope, methods or procedures of the auditing functions. The Committee is directly responsible for appointing the Company's independent registered public accounting firm and is charged with reviewing and approving all services performed for the Company by the independent registered public accounting firm and for reviewing and approving the related fees. The Committee reviews the independent registered public accounting firm's report on internal quality control and reviews all relationships between the independent registered public accounting firm and the Company, in order to assess the independent registered public accounting firm's independence. The Committee also reviews management's programs to monitor compliance with the Company's policies on business ethics and risk management. The Committee establishes procedures to receive and respond to complaints received by the Company regarding accounting, internal accounting controls, or auditing matters and allows for the confidential, anonymous submission of concerns by employees. The Audit Committee held nine meetings in 2012.

Management's Report on Internal Control Over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rule 13a-15(f) of the Securities Exchange Act of 1934. Using the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in Internal Control — Integrated Framework, management conducted an evaluation of the effectiveness of the Company's internal control over financial reporting under the supervision of the Chief Executive Officer and the Chief Financial Officer. Based on that evaluation, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2012.

Report of Independent Registered Public Accounting Firm

To the Stockholders and Board of Directors of FirstEnergy Corp.:

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, comprehensive income, common stockholders' equity, and cash flows present fairly, in all material respects, the financial position of FirstEnergy Corp. and its subsidiaries at December 31, 2012 and 2011, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2012 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under Item 15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2012, based on criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control over Financial Reporting. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP

Cleveland, Ohio
February 25, 2013

Report of Independent Registered Public Accounting Firm

To the Stockholder and Board of
Directors of FirstEnergy Solutions Corp.:

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income and comprehensive income, common stockholder's equity, and cash flows present fairly, in all material respects, the financial position of FirstEnergy Solutions Corp. and its subsidiaries at December 31, 2012 and 2011, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2012 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under Item 15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and financial statement schedule based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP

Cleveland, Ohio
February 25, 2013

Report of Independent Registered Public Accounting Firm

To the Stockholder and Board of
Directors of Ohio Edison Company:

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income and comprehensive income, common stockholder's equity, and cash flows present fairly, in all material respects, the financial position of Ohio Edison Company and its subsidiaries at December 31, 2012 and 2011, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2012 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under Item 15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and financial statement schedule based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP

Cleveland, Ohio
February 25, 2013

Report of Independent Registered Public Accounting Firm

To the Stockholder and Board of Directors of
Jersey Central Power & Light Company:

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income and comprehensive income, common stockholder's equity, and cash flows present fairly, in all material respects, the financial position of Jersey Central Power & Light Company and its subsidiaries at December 31, 2012 and 2011, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2012 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under Item 15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and financial statement schedule based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP

Cleveland, Ohio
February 25, 2013

FIRSTENERGY CORP.
CONSOLIDATED STATEMENTS OF INCOME

(In millions, except per share amounts)	For the Years Ended December 31, 2012	2011	2010
REVENUES:			
Electric utilities	$9,637	$10,400	$9,820
Unregulated businesses	5,666	5,747	3,519
Total revenues*	15,303	16,147	13,339
OPERATING EXPENSES:			
Fuel	2,471	2,317	1,432
Purchased power	4,237	4,875	4,624
Other operating expenses	3,769	3,964	2,714
Pensions and OPEB mark-to-market adjustment	609	507	190
Provision for depreciation	1,124	1,066	750
Deferral of storm costs	(375)	(145)	(14)
Amortization of other regulatory assets, net	307	474	736
General taxes	985	978	776
Impairment of long-lived assets	—	413	388
Total operating expenses	13,127	14,449	11,596
OPERATING INCOME	2,176	1,698	1,743
OTHER INCOME (EXPENSE):			
Gain on partial sale of Signal Peak	—	569	—
Investment income	77	114	117
Interest expense	(1,001)	(1,008)	(845)
Capitalized interest	72	70	165
Total other expense	(852)	(255)	(563)
INCOME BEFORE INCOME TAXES	1,324	1,443	1,180
INCOME TAXES	553	574	462
NET INCOME	771	869	718
Income (loss) attributable to noncontrolling interest	1	(16)	(24)
EARNINGS AVAILABLE TO FIRSTENERGY CORP.	$770	$885	$742
EARNINGS PER SHARE OF COMMON STOCK:			
Basic	$1.85	$2.22	$2.44
Diluted	$1.84	$2.21	$2.42
WEIGHTED AVERAGE NUMBER OF SHARES OUTSTANDING:			
Basic	418	399	304
Diluted	419	401	305

* Includes excise tax collections of $455 million, $486 million and $428 million in 2012, 2011 and 2010, respectively.

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

FIRSTENERGY CORP.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(In millions)	For the Years Ended December 31, 2012	2011	2010
NET INCOME	$771	$869	$718
OTHER COMPREHENSIVE INCOME (LOSS):			
Pensions and OPEB prior service costs	(115)	(90)	(220)
Amortized losses on derivative hedges	1	23	36
Change in unrealized gain on available-for-sale securities	(6)	19	8
Other comprehensive loss	(120)	(48)	(176)
Income tax benefits on other comprehensive loss	(79)	(49)	(74)
Other comprehensive income (loss), net of tax	(41)	1	(102)
COMPREHENSIVE INCOME	730	870	616
Comprehensive income (loss) attributable to noncontrolling interest	1	(16)	(24)
COMPREHENSIVE INCOME AVAILABLE TO FIRSTENERGY CORP.	$729	$886	$640

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

FIRSTENERGY CORP.
CONSOLIDATED BALANCE SHEETS

(In millions, except share amounts)	As of December 31, 2012	2011
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$172	$202
Receivables-		
Customers, net of allowance for uncollectible accounts of $40 in 2012 and $37 in 2011	1,614	1,525
Other, net of allowance for uncollectible accounts of $4 in 2012 and $3 in 2011	315	269
Materials and supplies, at average cost	861	811
Prepaid taxes	119	191
Derivatives	192	235
Accumulated deferred income taxes	319	—
Other	176	122
	3,768	3,355
PROPERTY, PLANT AND EQUIPMENT:		
In service	43,210	40,122
Less — Accumulated provision for depreciation	12,600	11,839
	30,610	28,283
Construction work in progress	2,293	2,054
	32,903	30,337
INVESTMENTS:		
Nuclear plant decommissioning trusts	2,204	2,112
Investments in lease obligation bonds	54	402
Other	936	1,008
	3,194	3,522
DEFERRED CHARGES AND OTHER ASSETS:		
Goodwill	6,447	6,441
Regulatory assets	2,375	2,030
Other	1,719	1,641
	10,541	10,112
	$50,406	$47,326
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Currently payable long-term debt	$1,999	$1,621
Short-term borrowings	1,969	—
Accounts payable	1,599	1,174
Accrued taxes	543	558
Accrued compensation and benefits	331	384
Derivatives	126	218
Other	1,038	900
	7,605	4,855
CAPITALIZATION:		
Common stockholders' equity-		
Common stock, $0.10 par value, authorized 490,000,000 shares - 418,216,437 shares outstanding	42	42

Other paid-in capital	9,769	9,765
Accumulated other comprehensive income	385	426
Retained earnings	2,888	3,047
Total common stockholders' equity	13,084	13,280
Noncontrolling interest	9	19
Total equity	13,093	13,299
Long-term debt and other long-term obligations	15,179	15,716
	28,272	29,015
NONCURRENT LIABILITIES:		
Accumulated deferred income taxes	6,616	5,670
Retirement benefits	3,080	2,823
Asset retirement obligations	1,599	1,497
Deferred gain on sale and leaseback transaction	892	925
Adverse power contract liability	506	469
Other	1,836	2,072
	14,529	13,456
COMMITMENTS, GUARANTEES AND CONTINGENCIES (Note 15)		
	$50,406	$47,326

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

FIRSTENERGY CORP.
CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDERS' EQUITY

(In millions, except share amounts)	Common Stock Number of Shares	Common Stock Par Value	Other Paid-In Capital	Accumulated Other Comprehensive Income	Retained Earnings
Balance, January 1, 2010	304,835,407	$31	$5,448	$527	$3,012
Earnings available to FirstEnergy Corp.					742
Change in unrealized loss on derivative hedges, net of $14 million of income taxes				22	
Change in unrealized gain on investments, net of $3 million of income taxes				5	
Pensions and OPEB, net of $91 million of income tax benefits (Note 2)				(129)	
Stock-based compensation			(4)		
Cash dividends declared on common stock					(670)
Balance, December 31, 2010	304,835,407	31	5,444	425	3,084
Earnings available to FirstEnergy Corp.					885
Change in unrealized loss on derivative hedges, net of $8 million of income taxes				15	
Change in unrealized gain on investments, net of $7 million of income taxes				12	
Pensions and OPEB, net of $64 million of income tax benefits (Note 2)				(26)	
Stock-based compensation			5		
Allegheny merger	113,381,030	11	4,316		
Cash dividends declared on common stock					(922)
Balance, December 31, 2011	418,216,437	42	9,765	426	3,047
Earnings available to FirstEnergy Corp.					770
Change in unrealized loss on derivative hedges, net of $1 million of income tax benefits				2	
Change in unrealized gain on investments, net of $2 million of income tax benefits				(4)	
Pensions and OPEB, net of $76 million of income tax benefits (Note 2)				(39)	
Stock-based compensation			4		
Cash dividends declared on common stock					(920)
Equity method adjustment (Note 8)					(9)
Balance, December 31, 2012	418,216,437	$42	$9,769	$385	$2,888

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

FIRSTENERGY CORP.
CONSOLIDATED STATEMENTS OF CASH FLOWS

	For the Years Ended December 31,		
(In millions)	2012	2011	2010
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net Income	$771	$869	$718
Adjustments to reconcile net income to net cash from operating activities-			
Provision for depreciation	1,124	1,066	750
Asset removal costs charged to income	203	55	18
Amortization of other regulatory assets, net	307	474	736
Deferral of storm costs	(375)	(145)	(14)
Nuclear fuel and lease amortization	210	201	168
Deferred purchased power and other costs	(238)	(278)	(254)
Deferred income taxes and investment tax credits, net	647	798	450
Impairments of long-lived assets (Note 10)	—	413	388
Investment impairments (Note 10)	27	19	33
Deferred rents and lease market valuation liability	(104)	(49)	(54)
Pensions and OPEB mark-to-market adjustment	609	507	190
Retirement benefits	(127)	(151)	(86)
Gain on asset sales	(17)	(545)	(2)
Commodity derivative transactions, net (Note 9)	(95)	(27)	(81)
Pension trust contributions	(600)	(372)	—
Cash collateral, net	16	(79)	(26)
Interest rate swap transactions	—	—	129
Gain on sale of investment securities held in trusts, net	(71)	(59)	(55)
Decrease (increase) in operating assets-			
Receivables	(13)	147	(177)
Materials and supplies	(50)	14	2
Prepayments and other current assets	(12)	101	100
Increase (decrease) in operating liabilities-			
Accounts payable	71	35	43
Accrued taxes	6	91	57
Accrued interest	(12)	(12)	7
Accrued compensation and benefits	(55)	69	21
Other	98	(79)	15
Net cash provided from operating activities	2,320	3,063	3,076
CASH FLOWS FROM FINANCING ACTIVITIES:			
New Financing-			
Long-term debt	750	604	1,099
Short-term borrowings, net	1,969	—	—
Redemptions and Repayments-			
Long-term debt	(940)	(1,909)	(1,015)
Short-term borrowings, net	—	(700)	(378)
Common stock dividend payments	(920)	(881)	(670)
Other	(52)	(38)	(19)
Net cash provided from (used for) financing activities	807	(2,924)	(983)
CASH FLOWS FROM INVESTING ACTIVITIES:			

Property additions	(2,678)	(2,129)	(1,780)
Nuclear fuel	(286)	(149)	(183)
Proceeds from asset sales	17	840	117
Sales of investment securities held in trusts	2,980	4,207	3,172
Purchases of investment securities held in trusts	(3,020)	(4,309)	(3,219)
Customer acquisition costs	(2)	(3)	(113)
Cash investments	102	60	66
Cash received in Allegheny merger	—	590	—
Asset removal costs	(229)	(114)	(35)
Other	(41)	51	27
Net cash used for investing activities	(3,157)	(956)	(1,948)
Net change in cash and cash equivalents	(30)	(817)	145
Cash and cash equivalents at beginning of period	202	1,019	874
Cash and cash equivalents at end of period	$172	$202	$1,019
SUPPLEMENTAL CASH FLOW INFORMATION:			
Non-cash transaction: common stock issued in merger with Allegheny	$—	$4,354	$—
Cash paid (received) during the year-			
Interest (net of amounts capitalized)	$962	$935	$662
Income taxes	$(6)	$(358)	$(42)

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

FIRSTENERGY SOLUTIONS CORP.
CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME

(In millions)	For the Years Ended December 31, 2012	2011	2010
STATEMENTS OF INCOME			
REVENUES:			
Electric sales to non-affiliates	$5,157	$4,502	$3,252
Electric sales to affiliates (Note 16)	515	752	2,227
Other	246	223	349
Total revenues	5,918	5,477	5,828
OPERATING EXPENSES:			
Fuel	1,287	1,344	1,403
Purchased power from affiliates (Note 16)	451	242	371
Purchased power from non-affiliates	1,881	1,378	1,585
Other operating expenses	1,360	1,630	1,230
Pensions and OPEB mark-to-market adjustment	166	171	107
Provision for depreciation	276	275	246
General taxes	136	124	94
Impairment of long-lived assets	—	294	388
Total operating expenses	5,557	5,458	5,424
OPERATING INCOME	361	19	404
OTHER INCOME (EXPENSE) (Note 16):			
Investment income	66	57	59
Miscellaneous income	35	30	17
Interest expense — affiliates	(10)	(8)	(10)
Interest expense — other	(191)	(203)	(206)
Capitalized interest	37	35	92
Total other expense	(63)	(89)	(48)
INCOME (LOSS) BEFORE INCOME TAXES	298	(70)	356
INCOME TAXES (BENEFITS)	111	(11)	125
NET INCOME (LOSS)	$187	$(59)	$231
STATEMENTS OF COMPREHENSIVE INCOME			
NET INCOME (LOSS)	$187	$(59)	$231
OTHER COMPREHENSIVE INCOME (LOSS):			
Pensions and OPEB prior service costs	6	(12)	(30)
Amortized gain (loss) on derivative hedges	(9)	12	23
Change in unrealized gain on available-for-sale securities	(5)	16	8
Other comprehensive income (loss)	(8)	16	1
Income taxes (benefits) on other comprehensive income (loss)	(4)	2	4

Other comprehensive income (loss), net of tax	(4)	14	(3)
COMPREHENSIVE INCOME (LOSS)	$183	$(45)	$228

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

FIRSTENERGY SOLUTIONS CORP.
CONSOLIDATED BALANCE SHEETS

	As of December 31,	
(In millions, except share amounts)	2012	2011
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$3	$7
Receivables-		
Customers, net of allowance for uncollectible accounts of $16 in 2012 and 2011	483	424
Affiliated companies	379	600
Other, net of allowance for uncollectible accounts of $2 in 2012 and $3 in 2011	91	61
Notes receivable from affiliated companies	276	383
Materials and supplies	505	492
Derivatives	190	219
Prepayments and other	55	38
	1,982	2,224
PROPERTY, PLANT AND EQUIPMENT:		
In service	11,997	10,983
Less — Accumulated provision for depreciation	4,408	4,110
	7,589	6,873
Construction work in progress	1,141	1,014
	8,730	7,887
INVESTMENTS:		
Nuclear plant decommissioning trusts	1,283	1,223
Other	12	7
	1,295	1,230
DEFERRED CHARGES AND OTHER ASSETS:		
Customer intangibles	110	123
Goodwill	24	24
Property taxes	36	43
Unamortized sale and leaseback costs	119	80
Derivatives	99	79
Other	253	129
	641	478
	$12,648	$11,819
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Currently payable long-term debt	$1,102	$905
Accounts payable-		
Affiliated companies	726	436
Other	159	220
Accrued taxes	171	227
Derivatives	124	189
Other	284	261
	2,566	2,238
CAPITALIZATION:		
Common stockholder's equity-		
Common stock, without par value, authorized 750 shares- 7 shares outstanding	1,573	1,570
Accumulated other comprehensive income	72	76

Retained earnings	2,118	1,931
Total common stockholder's equity	3,763	3,577
Long-term debt and other long-term obligations	3,118	2,799
	6,881	6,376
NONCURRENT LIABILITIES:		
Deferred gain on sale and leaseback transaction	892	925
Accumulated deferred income taxes	515	286
Asset retirement obligations	965	904
Retirement benefits	241	356
Lease market valuation liability	—	171
Other	588	563
	3,201	3,205
COMMITMENTS, GUARANTEES AND CONTINGENCIES (Note 15)		
	$12,648	$11,819

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

FIRSTENERGY SOLUTIONS CORP.
CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDER'S EQUITY

(In millions, except share amounts)	Common Stock Number of Shares	Common Stock Carrying Value	Accumulated Other Comprehensive Income	Retained Earnings
Balance, January 1, 2010	7	$1,545	$65	$1,759
Net income				231
Change in unrealized gain on derivative instruments, net of $9 of income taxes			14	
Change in unrealized gain on investments, net of $3 of income taxes			5	
Pensions and OPEB, net of $8 of income tax benefits (Note 2)			(22)	
Consolidated tax benefit allocation		22		
Balance, December 31, 2010	7	1,567	62	1,990
Net loss				(59)
Change in unrealized gain on derivative instruments, net of $5 of income taxes			7	
Change in unrealized gain on investments, net of $6 of income taxes			10	
Pensions and OPEB, net of $9 of income tax benefits (Note 2)			(3)	
Consolidated tax benefit allocation		3		
Balance, December 31, 2011	7	1,570	76	1,931
Net income				187
Change in unrealized gain on derivative instruments, net of $3 of income tax benefits			(6)	
Change in unrealized gain on investments, net of $2 of income tax benefits			(3)	
Pensions and OPEB, net of $1 of income taxes (Note 2)			5	
Stock-based compensation		2		
Consolidated tax benefit allocation		1		
Balance, December 31, 2012	7	$1,573	$72	$2,118

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

FIRSTENERGY SOLUTIONS CORP.
CONSOLIDATED STATEMENTS OF CASH FLOWS

(In millions)	For the Years Ended December 31, 2012	2011	2010
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net Income (loss)	$187	$(59)	$231
Adjustments to reconcile net income to net cash from operating activities-			
Provision for depreciation	276	275	246
Nuclear fuel and lease amortization	210	200	172
Deferred rents and lease market valuation liability	(100)	(42)	(47)
Deferred income taxes and investment tax credits, net	214	199	150
Impairments of long-lived assets (Note 10)	—	294	388
Investment impairments (Note 10)	14	17	32
Pensions and OPEB mark-to-market adjustment	166	171	107
Accrued compensation and retirement benefits	1	(41)	(25)
Pension trust contribution	(209)	—	—
Gain on investment securities held in trusts	(65)	(50)	(51)
Gain on asset sales	(17)	—	(2)
Commodity derivative transactions, net (Note 9)	(74)	(68)	(81)
Cash collateral, net	(33)	(88)	(7)
Decrease (increase) in operating assets-			
Receivables	135	(126)	(362)
Materials and supplies	(13)	16	(11)
Prepayments and other current assets	(18)	22	42
Increase (decrease) in operating liabilities-			
Accounts payable	214	(54)	(27)
Accrued taxes	(56)	159	2
Other	(11)	(6)	29
Net cash provided from operating activities	821	819	786
CASH FLOWS FROM FINANCING ACTIVITIES:			
New financing-			
Long-term debt	650	247	715
Short-term borrowings, net	3	(11)	2
Redemptions and repayments-			
Long-term debt	(429)	(856)	(772)
Short-term borrowings, net	—	—	—
Other	(12)	(11)	(2)
Net cash provided from (used for) financing activities	212	(631)	(57)
CASH FLOWS FROM INVESTING ACTIVITIES:			
Property additions	(795)	(600)	(852)
Nuclear fuel	(286)	(149)	(183)
Proceeds from asset sales	17	599	117
Sales of investment securities held in trusts	1,464	1,843	1,927
Purchases of investment securities held in trusts	(1,502)	(1,890)	(1,974)
Loans to affiliated companies, net	107	14	408
Customer acquisition costs	(2)	(3)	(113)

Leasehold improvement payments to associated companies	—	—	(51)
Other	(40)	(4)	1
Net cash provided from (used for) investing activities	(1,037)	(190)	(720)
Net change in cash and cash equivalents	(4)	(2)	9
Cash and cash equivalents at beginning of period	7	9	—
Cash and cash equivalents at end of period	$3	$7	$9
SUPPLEMENTAL CASH FLOW INFORMATION:			
Cash paid (received) during the year-			
Interest (net of amounts capitalized)	$174	$167	$117
Income taxes	$72	$(387)	$140

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

OHIO EDISON COMPANY
CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME

	For the Years Ended December 31,		
(In millions)	2012	2011	2010
STATEMENTS OF INCOME			
REVENUES:			
Electric sales	$1,512	$1,526	$1,729
Excise and gross receipts tax collections	103	107	107
Total revenues	1,615	1,633	1,836
OPERATING EXPENSES:			
Purchased power from affiliates	159	287	522
Purchased power from non-affiliates	274	272	316
Pensions & OPEB mark-to-market adjustment	84	43	24
Other operating expenses	491	451	342
Provision for depreciation	101	93	91
Amortization of regulatory assets, net	77	30	63
General taxes	193	190	183
Total operating expenses	1,379	1,366	1,541
OPERATING INCOME	236	267	295
OTHER INCOME (EXPENSE):			
Investment income	26	25	26
Interest expense	(90)	(88)	(89)
Capitalized interest	3	2	1
Total other expense	(61)	(61)	(62)
INCOME BEFORE INCOME TAXES	175	206	233
INCOME TAXES	74	78	78
NET INCOME	$101	$128	$155
STATEMENTS OF COMPREHENSIVE INCOME			
NET INCOME	$101	$128	$155
OTHER COMPREHENSIVE LOSS:			
Pensions and OPEB prior service costs	(24)	(43)	(31)
Other comprehensive loss	(24)	(43)	(31)
Income tax benefits on other comprehensive loss	(15)	(15)	(9)
Other comprehensive loss, net of tax	(9)	(28)	(22)
COMPREHENSIVE INCOME	$92	$100	$133

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

OHIO EDISON COMPANY
CONSOLIDATED BALANCE SHEETS

	As of December 31,	
(In millions, except share amounts)	2012	2011
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$50	$26
Receivables-		
Customers, net of allowance for uncollectible accounts of $4 in 2012 and 2011	176	163
Affiliated companies	54	86
Other	17	41
Notes receivable from affiliated companies	307	181
Prepayments and other	4	17
	608	514
UTILITY PLANT:		
In service	3,596	3,358
Less — Accumulated provision for depreciation	1,310	1,267
	2,286	2,091
Construction work in progress	124	91
	2,410	2,182
OTHER PROPERTY AND INVESTMENTS:		
Investment in lease obligation bonds	132	163
Nuclear plant decommissioning trusts	141	137
Other	93	90
	366	390
DEFERRED CHARGES AND OTHER ASSETS:		
Regulatory assets	268	363
Property taxes	90	81
Unamortized sale and leaseback costs	20	25
Other	20	19
	398	488
	$3,782	$3,574
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Currently payable long-term debt	$4	$2
Accounts payable-		
Affiliated companies	194	119
Other	35	35
Accrued taxes	100	88
Accrued interest	25	25
Other	80	79
	438	348
CAPITALIZATION:		
Common stockholder's equity-		
Common stock, without par value, authorized 175,000,000 shares – 60 shares outstanding	658	747
Accumulated other comprehensive income	45	54
Retained earnings (accumulated deficit)	17	(84)

Total common stockholder's equity	720	717
Noncontrolling interest	4	5
Total equity	724	722
Long-term debt and other long-term obligations	1,172	1,155
	1,896	1,877
NONCURRENT LIABILITIES:		
Accumulated deferred income taxes	767	787
Retirement benefits	283	213
Asset retirement obligations	76	71
Other	322	278
	1,448	1,349
COMMITMENTS AND CONTINGENCIES (Note 15)		
	$3,782	$3,574

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

OHIO EDISON COMPANY
CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDER'S EQUITY

(In millions, except share amounts)	Common Stock Number of Shares	Common Stock Carrying Value	Accumulated Other Comprehensive Income	Retained Earnings (Accumulated Deficit)
Balance, January 1, 2010	60	$1,116	$104	$(222)
Net income				155
Pension and OPEB, net of $9 of income tax benefits (Note 2)			(22)	
Consolidated tax benefit allocation		2		
Cash dividends declared on common stock				(45)
Return of capital to parent		(205)		
Balance, December 31, 2010	60	913	82	(112)
Net income				128
Pension and OPEB, net of $15 of income tax benefits (Note 2)			(28)	
Consolidated tax benefit allocation		2		
Cash dividends declared on common stock				(100)
Return of capital to parent		(168)		
Balance, December 31, 2011	60	747	54	(84)
Net income				101
Pension and OPEB, net of $15 of income tax benefits (Note 2)			(9)	
Consolidated tax benefit allocation		1		
Return of capital to parent		(90)		
Balance, December 31, 2012	60	$658	$45	$17

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

OHIO EDISON COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS

(In millions)	For the Years Ended December 31, 2012	2011	2010
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net Income	$101	$128	$155
Adjustments to reconcile net income to net cash from operating activities-			
Provision for depreciation	101	93	91
Amortization of regulatory assets, net	77	30	63
Amortization of lease costs	(9)	(9)	(9)
Deferred income taxes and investment tax credits, net	23	77	43
Pensions and OPEB mark-to-market adjustment	84	43	24
Accrued compensation and retirement benefits	(44)	(37)	(45)
Cash collateral, net	(2)	(6)	2
Pension trust contribution	—	(27)	—
Decrease (increase) in operating assets-			
Receivables	41	43	27
Prepayments and other current assets	13	(11)	14
Increase (decrease) in operating liabilities-			
Accounts payable	75	(5)	(21)
Accrued taxes	12	10	(3)
Other	—	(2)	(14)
Net cash provided from operating activities	472	327	327
CASH FLOWS FROM FINANCING ACTIVITIES:			
New financing-			
Short-term borrowings, net	—	—	49
Redemptions and Repayments-			
Long-term debt	—	—	(10)
Short-term borrowings, net	—	(142)	—
Common stock dividend payments/Return of capital	(90)	(268)	(250)
Other	(4)	(5)	(2)
Net cash used for financing activities	(94)	(415)	(213)
CASH FLOWS FROM INVESTING ACTIVITIES:			
Property additions	(226)	(149)	(150)
Leasehold improvement payments from affiliated companies	—	—	18
Sales of investment securities held in trusts	105	154	83
Purchases of investment securities held in trusts	(111)	(161)	(89)
Loans to affiliated companies, net	(126)	(164)	102
Cash investments	31	27	25
Other	(27)	(13)	(7)
Net cash used for investing activities	(354)	(306)	(18)
Net change in cash and cash equivalents	24	(394)	96
Cash and cash equivalents at beginning of period	26	420	324
Cash and cash equivalents at end of period	$50	$26	$420

SUPPLEMENTAL CASH FLOW INFORMATION:			
Cash paid (received) during the year-			
Interest (net of amounts capitalized)	$82	$82	$83
Income taxes	$27	$(69)	$76

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

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

	For the Years Ended December 31,		
(In millions)	2012	2011	2010
STATEMENTS OF INCOME			
REVENUES:			
Electric sales	$1,990	$2,445	$2,976
Excise tax collections	37	50	51
Total revenues	2,027	2,495	3,027
OPERATING EXPENSES:			
Purchased power	1,069	1,382	1,736
Other operating expenses	599	403	329
Pensions and OPEB mark-to-market adjustment	65	60	26
Provision for depreciation	109	103	107
Deferral of storm costs	(279)	(92)	(19)
Amortization of other regulatory assets, net	52	200	340
General taxes	55	67	65
Total operating expenses	1,670	2,123	2,584
OPERATING INCOME	357	372	443
OTHER INCOME (EXPENSE):			
Miscellaneous income	4	11	6
Interest expense	(122)	(124)	(120)
Capitalized interest	1	2	1
Total other expense	(117)	(111)	(113)
INCOME BEFORE INCOME TAXES	240	261	330
INCOME TAXES	107	117	147
NET INCOME	$133	$144	$183
STATEMENTS OF COMPREHENSIVE INCOME			
NET INCOME	$133	$144	$183
OTHER COMPREHENSIVE LOSS:			
Pensions and OPEB prior service costs	(19)	(27)	(17)
Other comprehensive loss	(19)	(27)	(17)
Income tax benefits on other comprehensive loss	(12)	(15)	(10)
Other comprehensive loss, net of tax	(7)	(12)	(7)
COMPREHENSIVE INCOME	$126	$132	$176

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

JERSEY CENTRAL POWER & LIGHT COMPANY
CONSOLIDATED BALANCE SHEETS

	As of December 31,	
(In millions, except share amounts)	2012	2011
ASSETS		
CURRENT ASSETS:		
Receivables-		
Customers, net of allowance for uncollectible accounts of $3 in 2012 and 2011	$221	$235
Affiliated companies	1	—
Other	18	17
Prepaid taxes	45	33
Other	27	19
	312	304
UTILITY PLANT:		
In service	5,479	4,872
Less — Accumulated provision for depreciation	1,820	1,743
	3,659	3,129
Construction work in progress	103	227
	3,762	3,356
OTHER PROPERTY AND INVESTMENTS:		
Nuclear fuel disposal trust	230	219
Nuclear plant decommissioning trusts	201	193
Other	2	2
	433	414
DEFERRED CHARGES AND OTHER ASSETS:		
Goodwill	1,811	1,811
Regulatory assets	791	408
Other	29	32
	2,631	2,251
	$7,138	$6,325
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Currently payable long-term debt	$36	$34
Short-term borrowings-		
Affiliated companies	365	259
Other	140	—
Accounts payable-		
Affiliated companies	272	19
Other	88	101
Accrued compensation and benefits	36	41
Customer deposits	23	24
Accrued taxes	14	15
Accrued interest	18	18
Other	23	21
	1,015	532
CAPITALIZATION:		
Common stockholder's equity-		
	136	136

Common stock, $10 par value, authorized 16,000,000 shares, 13,628,447 shares outstanding		
Other paid-in capital	2,011	2,011
Accumulated other comprehensive income	32	39
Retained earnings	64	121
Total common stockholder's equity	2,243	2,307
Long-term debt and other long-term obligations	1,701	1,736
	3,944	4,043
NONCURRENT LIABILITIES:		
Accumulated deferred income taxes	1,089	859
Power purchase contract liability	265	147
Nuclear fuel disposal costs	197	197
Retirement benefits	241	170
Asset retirement obligations	123	115
Other	264	262
	2,179	1,750
COMMITMENTS, GUARANTEES AND CONTINGENCIES (Note 15)		
	$7,138	$6,325

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

JERSEY CENTRAL POWER & LIGHT COMPANY
CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDER'S EQUITY

(In millions, except share amounts)	Common Stock		Other Paid-In Capital	Accumulated Other Comprehensive Income	Retained Earnings (Accumulated Deficit)
	Number of Shares	Par Value			
Balance, January 1, 2010	13,628,447	$136	$2,507	$58	$(41)
Net income					183
Pensions and OPEB, net of $10 of income tax benefits (Note 2)				(7)	
Cash dividends declared on common stock					(165)
Consolidated tax benefit allocation			2		
Balance, December 31, 2010	13,628,447	136	2,509	51	(23)
Net income					144
Pensions and OPEB, net of $15 of income tax benefits (Note 2)				(12)	
Return of capital to parent			(500)		
Consolidated tax benefit allocation			2		
Balance, December 31, 2010	13,628,447	136	2,011	39	121
Net income					133
Pensions and OPEB, net of $12 of income tax benefits (Note 2)				(7)	
Cash dividends declared on common stock					(190)
Balance, December 31, 2012	13,628,447	$136	$2,011	$32	$64

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

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JERSEY CENTRAL POWER & LIGHT COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS

	For the Years Ended December 31,		
(In millions)	2012	2011	2010
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net Income	$133	$144	$183
Adjustments to reconcile net income to net cash from operating activities-			
Provision for depreciation	109	103	107
Asset removal costs charged to income	166	32	6
Deferral of storm costs	(279)	(92)	(19)
Amortization of other regulatory assets, net	52	200	340
Deferred purchased power and other costs	(105)	(93)	(105)
Deferred income taxes and investment tax credits, net	245	91	31
Pensions and OPEB mark-to-market adjustment	65	60	26
Accrued compensation and retirement benefits	(37)	(32)	(7)
Cash collateral, net	4	—	(23)
Pension trust contribution	—	(105)	—
Decrease (increase) in operating assets-			
Receivables	12	160	(67)
Prepaid taxes	(12)	(22)	24
Decrease (increase) in operating liabilities-			
Accounts payable	7	(83)	(20)
Accrued taxes	(2)	11	12
Other	26	11	(11)
Net cash provided from operating activities	384	385	477
CASH FLOWS FROM FINANCING ACTIVITIES:			
New Financing-			
Short-term borrowings, net	246	259	—
Redemptions and Repayments-			
Long-term debt	(34)	(32)	(31)
Common stock dividend payments/ Return of capital	(190)	(500)	(165)
Other	—	(1)	—
Net cash used for financing activities	22	(274)	(196)
CASH FLOWS FROM INVESTING ACTIVITIES:			
Property additions	(293)	(229)	(182)
Loans to affiliated companies, net	—	177	(74)
Sales of investment securities held in trusts	516	779	411
Purchases of investment securities held in trusts	(530)	(796)	(428)
Asset removal costs	(93)	(35)	(6)
Other	(6)	(7)	(2)
Net cash used for investing activities	(406)	(111)	(281)
Net change in cash and cash equivalents	—	—	—
Cash and cash equivalents at beginning of period	—	—	—

Cash and cash equivalents at end of period	$—	$—	$—
SUPPLEMENTAL CASH FLOW INFORMATION:			
Cash paid (received) during the year-			
Interest (net of amounts capitalized)	$118	$118	$117
Income taxes	$(51)	$(8)	$145

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

FIRSTENERGY CORP. AND SUBSIDIARIES

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. ORGANIZATION, BASIS OF PRESENTATION AND SIGNIFICANT ACCOUNTING POLICIES

Unless otherwise indicated, defined terms and abbreviations used herein have the meanings set forth in the accompanying Glossary of Terms.

FE is a diversified energy holding company that holds, directly or indirectly, all of the outstanding common stock of its principal subsidiaries: OE, CEI, TE, Penn (a wholly owned subsidiary of OE), JCP&L, ME, PN, FENOC, AE and its principal subsidiaries (AE Supply, AGC, MP, PE, WP and FET), FES and its principal subsidiaries (FG and NG) and FESC. AE merged with a subsidiary of FirstEnergy on February 25, 2011, with AE continuing as the surviving corporation and becoming a wholly owned subsidiary of FirstEnergy (See Note 19, Merger). Accordingly, consolidated results of operations for the year ended December 31, 2011, include just ten months of Allegheny results. FirstEnergy follows GAAP and complies with the related regulations, orders, policies and practices prescribed by the SEC, FERC, and, as applicable, the PUCO, the PPUC, the MDPSC, the NYPSC, the WVPSC, the VSCC and the NJBPU. The preparation of financial statements in conformity with GAAP requires management to make periodic estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses and disclosure of contingent assets and liabilities. Actual results could differ from these estimates. The reported results of operations are not indicative of results of operations for any future period. FE and its subsidiaries have evaluated events and transactions for potential recognition or disclosure through the date the financial statements were issued.
FE and its subsidiaries consolidate all majority-owned subsidiaries over which they exercise control and, when applicable, entities for which they have a controlling financial interest. Intercompany transactions and balances are eliminated in consolidation. FE and its subsidiaries consolidate a VIE when it is determined that it is the primary beneficiary (see Note 7, Variable Interest Entities). Investments in affiliates over which FE and its subsidiaries have the ability to exercise significant influence, but with respect to which they are not the primary beneficiary and do not exercise control, follow the equity method of accounting. Under the equity method, the interest in the entity is reported as an investment in the Consolidated Balance Sheets and the percentage share of the entity's earnings is reported in the Consolidated Statements of Income and Comprehensive Income. These Notes to the Consolidated Financial Statements are combined for FirstEnergy, FES, OE and JCP&L.

Certain prior year amounts have been reclassified to conform to the current year presentation.

ACCOUNTING FOR THE EFFECTS OF REGULATION
FirstEnergy accounts for the effects of regulation through the application of regulatory accounting to the Utilities, ATSI, PATH and TrAIL since their rates are established by a third-party regulator with the authority to set rates that bind customers, are cost-based and can be charged to and collected from customers.
FirstEnergy records regulatory assets and liabilities that result from the regulated rate-making process that would not be recorded under GAAP for non-regulated entities. These assets and liabilities are amortized in the Consolidated Statements of Income concurrent with the recovery or refund through customer rates. FirstEnergy believes that it is probable that its regulatory assets and liabilities will be recovered and settled, respectively, through future rates. FirstEnergy and the Utilities net their regulatory assets and liabilities based on federal and state jurisdictions.

The following table provides information about the composition of net regulatory assets as of December 31, 2012 and December 31, 2011, and the changes during the year ended December 31, 2012:

Regulatory Assets by Source	December 31, 2012	December 31, 2011	Increase (Decrease)
	(In millions)		
Regulatory transition costs	$281	$309	$(28)
Customer receivables for future income taxes	508	519	(11)
Nuclear decommissioning and spent fuel disposal costs	(219)	(210)	(9)
Asset removal costs	(372)	(347)	(25)
Deferred transmission costs	390	340	50
Deferred generation costs	379	400	(21)
Deferred distribution costs	231	267	(36)
Contract valuations	463	299	164
Storm-related costs	509	144	365
Other	205	309	(104)
Total	$2,375	$2,030	$345

Regulatory assets that do not earn a current return totaled approximately $779 million as of December 31, 2012. JCP&L had $386 million of regulatory assets not earning a current return, which include storm damage costs. The remaining $393 million of regulatory assets include PJM transmission and regulatory transition costs that are expected to be recovered by 2020.

As of December 31, 2012 and December 31, 2011, FirstEnergy had approximately $392 million and $381 million, respectively, of net regulatory liabilities, that are primarily related to asset removal costs. Net regulatory liabilities are classified within Other Noncurrent Liabilities on the Consolidated Balance Sheets.

Transition Cost Amortization

JCP&L's regulatory transition costs include the deferral of above-market costs for power supplied from NUGs of $120 million that are recovered through non-utility generation charge revenues. Projected above-market NUG costs are adjusted to fair value at the end of each quarter, with a corresponding offset to regulatory assets. Recovery of the remaining regulatory transition costs is expected to continue pursuant to various regulatory proceedings in New Jersey (see Note 14, Regulatory Matters).

REVENUES AND RECEIVABLES

The Utilities' principal business is providing electric service to customers in Ohio, Pennsylvania, West Virginia, New Jersey and Maryland. FES' and AE Supply's principal business is supplying electric power to end-use customers through retail and wholesale arrangements, including affiliated company power sales to meet a portion of the POLR and default service requirements of the Ohio and Pennsylvania Companies and competitive retail sales to customers primarily in Ohio, Pennsylvania, Illinois, Michigan, New Jersey and Maryland. Retail customers are metered on a cycle basis.

Electric revenues are recorded based on energy delivered through the end of the calendar month. An estimate of unbilled revenues is calculated to recognize electric service provided from the last meter reading through the end of the month. This estimate includes many factors, among which are historical customer usage, load profiles, estimated weather impacts, customer shopping activity and prices in effect for each class of customer. In each accounting period, the Utilities, FES and AE Supply accrue the estimated unbilled amount receivable as revenue and reverse the related prior period estimate.

Receivables from customers include retail electric sales and distribution deliveries to residential, commercial and industrial customers for the Utilities, and retail and wholesale sales to customers for FES and AE Supply. There was no material concentration of receivables as of December 31, 2012 and 2011 with respect to any particular segment of FirstEnergy's customers. Billed and unbilled customer receivables as of December 31, 2012 and 2011 are shown below.

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Customer Receivables	FirstEnergy	FES	OE	JCP&L
	(In millions)			
December 31, 2012				
Billed	$893	$243	$96	$124
Unbilled	721	240	80	97
Total	$1,614	$483	$176	$221
December 31, 2011				
Billed	$800	$220	$67	$117
Unbilled	725	204	96	118
Total	$1,525	$424	$163	$235

EARNINGS PER SHARE OF COMMON STOCK

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

Reconciliation of Basic and Diluted Earnings per Share of Common Stock	2012	2011	2010
	(In millions, except per share amounts)		
Weighted average number of basic shares outstanding	418	399	304
Assumed exercise of dilutive stock options and awards[(1)]	1	2	1
Weighted average number of diluted shares outstanding	419	401	305
Earnings available to FirstEnergy Corp.	$770	$885	$742
Basic earnings per share of common stock	$1.85	$2.22	$2.44
Diluted earnings per share of common stock	$1.84	$2.21	$2.42

(1) The number of potentially dilutive securities not included in the calculation of diluted shares outstanding due to their antidilutive effect were not significant for the years ending December 31, 2012, 2011 or 2010.

PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment reflects original cost (net of any impairments recognized), including payroll and related costs such as taxes, employee benefits, administrative and general costs, and interest costs incurred to place the assets in service. The costs of normal maintenance, repairs and minor replacements are expensed as incurred. FirstEnergy recognizes liabilities for planned major maintenance projects as they are incurred. Property, plant and equipment balances as of December 31, 2012 and 2011 were as follows:

	December 31, 2012			December 31, 2011		
Property, Plant and Equipment	Unregulated	Regulated	Total	Unregulated	Regulated	Total
	(In millions)					
In service	$16,658	$26,552	$43,210	$15,472	$24,650	$40,122
Less - Accumulated depreciation	(4,870)	(7,730)	(12,600)	(4,424)	(7,415)	(11,839)
Net plant in service	$11,788	$18,822	$30,610	$11,048	$17,235	$28,283

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FirstEnergy provides for depreciation on a straight-line basis at various rates over the estimated lives of property included in plant in service. The respective annual composite rates for FirstEnergy's subsidiaries' electric plant in 2012, 2011 and 2010 are shown in the following table:

	Annual Composite Depreciation Rate		
	2012	2011	2010
FG	3.0 %	3.1 %	4.0 %
NG	2.5 %	3.2 %	3.1 %
OE	2.9 %	2.9 %	2.9 %
JCP&L	2.1 %	2.1 %	2.2 %

Jointly Owned Plants

FE, through its subsidiary, AGC, owns an undivided 40% interest (1,109 MWs) in a 2,773 MW pumped storage, hydroelectric station in Bath County, Virginia, operated by the 60% owner, Virginia Electric and Power Company, a non-affiliated utility. Net Property, Plant and Equipment includes $447 million, excluding $19 million of CWIP, representing AGC's share in this facility as of December 31, 2012. AGC is obligated to pay its share of the costs of this jointly-owned facility in the same proportion as its ownership interest using its own financing. AGC's share of direct expenses of the joint plant is included in FirstEnergy Corp.'s operating expenses on the Consolidated Statement of Income.

Asset Retirement Obligations

FE recognizes an ARO for the future decommissioning of its nuclear power plants and future remediation of other environmental liabilities associated with all of its long-lived assets. The ARO liability represents an estimate of the fair value of FE's current obligation related to nuclear decommissioning and the retirement or remediation of environmental liabilities of other assets. A fair value measurement inherently involves uncertainty in the amount and timing of settlement of the liability. FE uses an expected cash flow approach to measure the fair value of the nuclear decommissioning and environmental remediation ARO. This approach applies probability weighting to discounted future cash flow scenarios that reflect a range of possible outcomes. The scenarios consider settlement of the ARO at the expiration of the nuclear power plant's current license, settlement based on an extended license term and expected remediation dates. The fair value of an ARO is recognized in the period in which it is incurred. The associated asset retirement costs are capitalized as part of the carrying value of the long-lived asset and are depreciated over the life of the related asset. AROs as of December 31, 2012, are described further in Note 13, Asset Retirement Obligations.

ASSET IMPAIRMENTS

Long-lived Assets

FirstEnergy reviews long-lived assets, including regulatory assets, for impairment whenever events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. The recoverability of a long-lived asset is measured by comparing its carrying value to the sum of undiscounted future cash flows expected to result from the use and eventual disposition of the asset. If the carrying value is greater than the undiscounted cash flows, impairment exists and a loss is recognized for the amount by which the carrying value of the long-lived asset exceeds its estimated fair value. Impairments of long-lived assets recognized for the year ended December 31, 2012, are described further in Note 10, Impairment of Long-Lived Assets.

Goodwill

In a business combination, the excess of the purchase price over the estimated fair values of the assets acquired and liabilities assumed is recognized as goodwill. Goodwill is evaluated for impairment at least annually and more frequently if indicators of impairment arise. In evaluating goodwill for impairment, FirstEnergy first assesses qualitative factors to determine whether it is more likely than not (that is, likelihood of more than 50 percent) that the fair value of a reporting unit is less than its carrying value (including goodwill). If FirstEnergy concludes that it is not more likely than not that the fair value of a reporting unit is less than its carrying value, then no further testing is required. However, if FirstEnergy concludes that it is more likely than not that the fair value of a reporting unit is less than its carrying value, then the two-step goodwill impairment test is performed to identify potential goodwill impairment and measure the amount of goodwill impaired to be recognized, if any.

FirstEnergy's reporting units are consistent with its operating entities, which aggregate to reportable segments and consist of Regulated Distribution, Regulated Transmission, Competitive Energy Services and Other/Corporate. Goodwill is allocated to these reportable segments based on the original purchase price allocation for acquisitions within various reporting units.

Annual impairment testing is conducted during the third quarter of each year and for 2012, 2011 and 2010 the analysis indicated no impairment of goodwill. The 2012 annual goodwill impairment test was performed primarily using a qualitative assessment approach. FirstEnergy assessed economic, industry and market considerations in addition to overall financial performance of its reporting units. It was determined that the fair values of FirstEnergy's reporting units were, more likely than not, greater than their carrying values.

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

Goodwill	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Other/Corporate	Consolidated
	(In millions)				
Balance as of December 31, 2011	$5,551	$—	$890	$ —	$6,441
Purchase Accounting Adjustment	—	—	6	—	6
Segment Reorganization[(1)]	(526)	526	—	—	—
Balance as of December 31, 2012	$5,025	$526	$896	$ —	$6,447

(1) Note 18, Segment Information discusses the modification of reporting segments that occurred during 2012 that resulted in the transfer of goodwill from Regulated Distribution to Regulated Transmission.

As of December 31, 2012 and 2011, total goodwill recognized by FES and JCP&L was $24 million and $1,811 million, respectively. FirstEnergy, FES and JCP&L have no accumulated impairment charge as of December 31, 2012.

Investments

At the end of each reporting period, FirstEnergy evaluates its investments for OTTI. Investments classified as available-for-sale securities are evaluated to determine whether a decline in fair value below the cost basis is other than temporary. FirstEnergy first considers its intent and ability to hold an equity security until recovery and then considers, among other factors, the duration and the extent to which the security's fair value has been less than its cost and the near-term financial prospects of the security issuer when evaluating an investment for impairment. For debt securities, FirstEnergy considers its intent to hold the securities, the likelihood that it will be required to sell the securities before recovery of its cost basis and the likelihood of recovery of the securities' entire amortized cost basis. If the decline in fair value is determined to be other than temporary, the cost basis of the securities is written down to fair value.

Unrealized gains and losses on available-for-sale securities are recognized in OCI. However, unrealized losses held in the NDTs of FES and OE are recognized in earnings since the trust arrangements, as they are currently defined, do not meet the required ability and intent to hold criteria in consideration of OTTI. The NDTs of JCP&L are subject to regulatory accounting, and therefore, net unrealized gains and losses are recorded as regulatory assets or liabilities because the difference between investments held in the trust and the decommissioning liabilities is expected to be recovered from or refunded to customers. In 2012, 2011 and 2010, FirstEnergy recognized $16 million, $19 million and $33 million, respectively, of OTTI. The fair values of FirstEnergy’s investments are disclosed in Note 8, Fair Value Measurements.

ACCUMULATED OTHER COMPREHENSIVE INCOME

AOCI, net of tax, included on FirstEnergy’s, FES’, OE's and JCP&L's Consolidated Balance Sheets as of December 31, 2012 and 2011, is comprised of the following:

Accumulated Other Comprehensive Income	FirstEnergy	FES	OE	JCP&L
	(In millions)			
Net liability for unfunded retirement benefits	$408	$56	$45	$33
Unrealized gain on investments	15	13	—	—
Unrealized gain (loss) on derivative hedges	(38)	3	—	(1)
Balance, December 31, 2012	$385	$72	$45	$32
Net liability for unfunded retirement benefits	$446	$52	$54	$40
Unrealized gain on investments	19	16	—	—
Unrealized gain (loss) on derivative hedges	(39)	8	—	(1)
Balance, December 31, 2011	$426	$76	$54	$39

OCI reclassified to net income during the three years ended December 31, 2012, 2011 and 2010 is shown in the following table.

	FirstEnergy (In millions)	FES	OE	JCP&L
2012				
Pensions and OPEB	$191	$20	$29	$24
Gain on investments	72	65	—	—
Gain on derivative hedges	—	9	—	—
	263	94	29	24
Income taxes related to reclassification to net income	101	35	11	10
Reclassification to net income	$162	$59	$18	$14
2011				
Pensions and OPEB	$169	$18	$28	$25
Gain on investments	59	51	6	—
Loss on derivative hedges	(38)	(32)	—	—
	190	37	34	25
Income taxes related to reclassification to net income	72	14	12	10
Reclassification to net income	$118	$23	$22	$15
2010				
Pensions and OPEB	$87	$46	$23	$5
Gain on investments	54	50	2	—
Loss on derivative hedges	(35)	(24)	—	—
	106	72	25	5
Income taxes related to reclassification to net income	40	26	9	3
Reclassification to net income	$66	$46	$16	$2

NEW ACCOUNTING PRONOUNCEMENTS

New accounting pronouncements not yet effective are not expected to have a material effect on the financial statements of FE or its subsidiaries.

2. PENSIONS AND OTHER POSTEMPLOYMENT BENEFITS

FirstEnergy provides noncontributory qualified defined benefit pension plans that cover substantially all of its employees and non-qualified pension plans that cover certain employees. The plans provide defined benefits based on years of service and compensation levels. In addition, FirstEnergy provides a minimum amount of noncontributory life insurance to retired employees in addition to optional contributory insurance. Health care benefits, which include certain employee contributions, deductibles and co-payments, are also available upon retirement to certain employees, their dependents and, under certain circumstances, their survivors. FirstEnergy recognizes the expected cost of providing pensions and OPEB to employees and their beneficiaries and covered dependents from the time employees are hired until they become eligible to receive those benefits. FirstEnergy also has obligations to former or inactive employees after employment, but before retirement, for disability-related benefits. During 2012, FirstEnergy amended its OPEB plan to reduce the limit of life insurance benefits for active employees and retirees resulting in a reduction to OPEB liabilities of approximately $85 million.

FirstEnergy's pensions and OPEB funding policy is based on actuarial computations using the projected unit credit method. During the year ended December 31, 2012, FirstEnergy made a voluntary $600 million contribution to its qualified pension plan. Pension and OPEB costs are affected by employee demographics (including age, compensation levels and employment periods), the level of contributions made to the plans and earnings on plan assets. Pension and OPEB costs may also be affected by changes in key assumptions, including anticipated rates of return on plan assets, the discount rates and health care trend rates used in determining the projected benefit obligations for pension and OPEB costs. FirstEnergy uses a December 31 measurement date for its pension and OPEB plans. The fair value of the plan assets represents the actual market value as of the measurement date.

As a result of the merger with AE, FirstEnergy assumed Allegheny's pension and OPEB plans. Subsequent to the merger date, FirstEnergy became the sponsor and Plan Administrator of the Allegheny Pension Plan. Effective January 1, 2012, most eligible participants in the Allegheny Pension Plan became eligible to participate in the FirstEnergy Corp. Pension Plan. The net assets of the Allegheny Pension Plan in the amount of $1.1 billion were merged into the FirstEnergy Corp. Pension Plan as of June 30, 2012.

Obligations and Funded Status	Pensions		OPEB	
	2012	2011	2012	2011
	(In millions)			
Change in benefit obligation:				
Benefit obligation as of January 1	$7,977	$5,858	$1,037	$861
Liabilities assumed with Allegheny Merger	—	1,341	—	272
Service cost	161	130	12	13
Interest cost	389	374	47	48
Plan participants' contributions	—	—	17	39
Plan amendments	8	—	(85)	(98)
Special termination benefits	—	6	—	—
Medicare retiree drug subsidy	—	—	—	9
Actuarial (gain) loss	861	647	152	19
Benefits paid	(421)	(379)	(104)	(126)
Benefit obligation as of December 31	$8,975	$7,977	$1,076	$1,037
Change in fair value of plan assets:				
Fair value of plan assets as of January 1	$5,867	$4,544	$528	$498
Assets assumed with Allegheny Merger	—	954	—	75
Actual return on plan assets	611	364	48	23
Company contributions	614	384	19	19
Plan participants' contributions	—	—	17	39
Benefits paid	(421)	(379)	(104)	(126)
Fair value of plan assets as of December 31	$6,671	$5,867	$508	$528
Funded Status:				
Qualified plan	$(1,967)	$(1,820)		
Non-qualified plans	(336)	(290)		
Funded Status	$(2,303)	$(2,110)	$(566)	$(509)
Accumulated benefit obligation	$8,355	$7,409	$—	$—
Amounts Recognized on the Balance Sheet:				
Current liabilities	$(14)	$(13)	$45	$—
Noncurrent liabilities	(2,289)	(2,097)	(611)	(509)
Net liability as of December 31	$(2,303)	$(2,110)	$(566)	$(509)
Amounts Recognized in AOCI:				
Prior service cost (credit)	$58	$67	$(728)	$(847)
Assumptions Used to Determine Benefit Obligations (as of December 31)				
Discount rate	4.25%	5.00%	4.00%	4.75%
Rate of compensation increase	4.70%	5.20%	N/A	N/A
Assumed Health Care Cost Trend Rates (as of December 31)				
	N/A	N/A	7.5-8.0%	7.5-8.5%

Health care cost trend rate assumed (pre/post-Medicare)								
Rate to which the cost trend rate is assumed to decline (the ultimate trend rate)	N/A		N/A		5	%	5	%
Year that the rate reaches the ultimate trend rate (pre/post-Medicare)	N/A		N/A		2020		2016-2018	
Allocation of Plan Assets (as of December 31)								
Equity securities	15	%	19	%	39	%	38	%
Bonds	47		48		40		44	
Absolute return strategies	22		21		4		13	
Real estate	5		6		1		1	
Private equities	1		2		—		—	
Cash and short-term securities	10		4		16		4	
Total	100	%	100	%	100	%	100	%

The estimated 2013 amortization of pensions and OPEB prior service costs (credits) from AOCI into net periodic pensions and OPEB costs (credits) is approximately $12 million and $(201) million, respectively.

Components of Net Periodic Benefit Costs	Pensions 2012	2011	2010	OPEB 2012	2011	2010
	(In millions)					
Service cost	$161	$130	$99	$12	$13	$10
Interest cost	389	374	314	47	48	45
Expected return on plan assets	(486)	(446)	(361)	(37)	(40)	(36)
Amortization of prior service cost (credit)	12	14	13	(203)	(203)	(193)
Other adjustments (settlements, curtailments, etc.)	—	6	—	—	—	—
Pensions & OPEB mark-to-market adjustment	735	729	264	140	36	22
Net periodic cost	$811	$807	$329	$(41)	$(146)	$(152)

Assumptions Used to Determine Net Periodic Benefit Cost for Years Ended December 31	Pensions 2012	2011	2010	OPEB 2012	2011	2010
Weighted-average discount rate	5.00%	5.50%	6.00%	4.75%	5.00%	5.75%
Expected long-term return on plan assets	7.75%	8.25%	8.50%	7.75%	8.50%	8.50%
Rate of compensation increase	5.20%	5.20%	5.20%	N/A	N/A	N/A

In selecting an assumed discount rate, FirstEnergy considers currently available rates of return on high-quality fixed income investments expected to be available during the period to maturity of the pensions and OPEB obligations. The assumed rates of return on plan assets consider historical market returns and economic forecasts for the types of investments held by FirstEnergy's pension trusts. The long-term rate of return is developed considering the portfolio's asset allocation strategy.

The following tables set forth pension financial assets that are accounted for at fair value by level within the fair value hierarchy. See Note 8, Fair Value Measurements, for a description of each level of the fair value hierarchy. There were no significant transfers between levels during 2012 and 2011.

	December 31, 2012				
	Level 1	Level 2	Level 3	Total	Asset Allocation
	(In millions)				
Cash and short-term securities	$—	$652	$—	$652	10%
Equity investments					
Domestic	547	8	—	555	8%
International	275	153	—	428	7%
Fixed income					
Government bonds	4	564	—	568	8%
Corporate bonds	—	1,899	—	1,899	28%
High Yield Debt	—	369	—	369	6%
Mortgaged-backed securities (non-government)	—	330	—	330	5%
Alternatives					
Hedge funds	—	1,498	—	1,498	22%
Derivatives	—	18	—	18	—%
Private equity funds	—	—	33	33	1%
Real estate funds	—	—	357	357	5%
	$826	$5,491	$390	$6,707	100%

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	December 31, 2011				Asset	
	Level 1	Level 2	Level 3	Total	Allocation	
	(In millions)					
Cash and short-term securities	$—	$198	$—	$198	4	%
Equity investments						
Domestic	223	323	—	546	9	%
International	198	379	—	577	10	%
Fixed income						
Government bonds	348	430	—	778	13	%
Corporate bonds	—	1,998	—	1,998	34	%
High yield debt	—	—	—	—	—	%
Mortgaged-backed securities (non-government)	—	48	—	48	1	%
Alternatives						
Hedge funds	—	1,131	—	1,131	19	%
Derivatives	—	75	70	145	2	%
Private equity funds	—	—	135	135	2	%
Real estate funds	—	—	327	327	6	%
	$769	$4,582	$532	$5,883	100	%

The following table provides a reconciliation of changes in the fair value of pension investments classified as Level 3 in the fair value hierarchy during 2012 and 2011:

	Private Equity Funds	Real Estate Funds	Derivatives
	(In millions)		
Balance as of January 1, 2011	$119	$282	$—
Actual return on plan assets:			
Unrealized gains	11	28	7
Realized gains	5	17	—
Purchases, sales and settlements	—	—	63
Transfers in (out)	—	—	—
Balance as of December 31, 2011	135	327	70
Actual return on plan assets:			
Unrealized gains (losses)	(14)	29	—
Realized gains (losses)	(10)	4	—
Purchases, sales and settlements	—	—	(70)
Transfers out	(78)	(3)	—
Balance as of December 31, 2012	$33	$357	$—

As of December 31, 2012 and 2011, the OPEB trust investments measured at fair value were as follows:

	December 31, 2012				Asset	
	Level 1	Level 2	Level 3	Total	Allocation	
	(In millions)					
Cash and short-term securities	$—	$83	$—	$83	16	%
Equity investment						
Domestic	183	—	—	183	36	%
International	4	2	—	6	1	%
Mutual funds	8	3	—	11	2	%
Fixed income						
U.S. treasuries	—	48	—	48	9	%
Government bonds	—	88	—	88	17	%
Corporate bonds	—	59	—	59	11	%
High yield debt	—	5	—	5	1	%
Mortgage-backed securities (non-government)	—	9	—	9	2	%
Alternatives						
Hedge funds	—	21	—	21	4	%
Private equity funds	—	—	—	—	—	%
Real estate funds	—	—	5	5	1	%
	$195	$318	$5	$518	100	%

	December 31, 2011				Asset	
	Level 1	Level 2	Level 3	Total	Allocation	
	(In millions)					
Cash and short-term securities	$—	$19	$—	$19	4	%
Equity investment						
Domestic	164	25	—	189	35	%
International	15	3	—	18	3	%
Mutual funds	7	2	—	9	2	%
Fixed income						
U.S. treasuries	—	30	—	30	6	%
Government bonds	8	136	—	144	27	%
Corporate bonds	—	89	—	89	17	%
Mortgage-backed securities (non-government)	—	5	—	5	—	%
Alternatives						
Hedge funds	—	25	—	25	5	%
Private equity funds	—	—	3	3	—	%
Real estate funds	—	—	7	7	1	%
	$194	$334	$10	$538	100	%

The following table provides a reconciliation of changes in the fair value of OPEB trust investments classified as Level 3 in the fair value hierarchy during 2012 and 2011:

	Private Equity Funds	Real Estate Funds
	(in millions)	
Balance as of January 1, 2011	$3	$9
Actual return on plan assets:		
Unrealized gains (losses)	—	1
Transfers out	—	(3)
Balance as of December 31, 2011	3	7
Actual return on plan assets:		
Unrealized gains	(1)	—
Realized gains (losses)	—	—
Purchases, sales and settlements	—	—
Transfers in (out)	(2)	(2)
Balance as of December 31, 2012	$—	$5

FirstEnergy follows a total return investment approach using a mix of equities, fixed income and other available investments while taking into account the pension plan liabilities to optimize the long-term return on plan assets for a prudent level of risk. Risk tolerance is established through careful consideration of plan liabilities, plan funded status and corporate financial condition. The investment portfolio contains a diversified blend of equity and fixed-income investments. Equity investments are diversified across U.S. and non-U.S. stocks, as well as growth, value, and small and large capitalization funds. Other assets such as real estate and private equity are used to enhance long-term returns while improving portfolio diversification. Derivatives may be used to gain market exposure in an efficient and timely manner; however, derivatives are not used to leverage the portfolio beyond the market value of the underlying investments. Investment risk is measured and monitored on a continuing basis through periodic investment portfolio reviews, annual liability measurements and periodic asset/liability studies.

FirstEnergy's target asset allocations for its pensions and OPEB trust portfolios for 2012 and 2011 are shown in the following table:

	Target Asset Allocations	
	2012	2011
Equities	20%	23%
Fixed income	51	50
Absolute return strategies	21	19
Real estate	5	6
Private equity	—	2
Cash	3	—
	100%	100%

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. A one-percentage-point change in assumed health care cost trend rates would have the following effects:

	1-Percentage-Point Increase	1-Percentage-Point Decrease
	(in millions)	
Effect on total of service and interest cost	$3	$(3)
Effect on accumulated benefit obligation	$34	$(30)

Taking into account estimated employee future service, FirstEnergy expects to make the following benefit payments from plan assets and other payments, net of participant contributions:

	Pensions	OPEB Benefit Payments	Subsidy Receipts
	(in millions)		
2013	$439	$157	$(3)
2014	473	127	(3)
2015	486	68	(3)
2016	496	68	(3)
2017	505	68	(3)
Years 2018-2022	2,687	337	(13)

FES’, OE's and JCP&L's shares of the net pensions and OPEB liability as of December 31, 2012 and 2011, were as follows:

	Pensions		OPEB	
Net Liability	2012	2011	2012	2011
	(In millions)			
FES	$(180)	$(313)	$(36)	$(18)
OE	(182)	(108)	(78)	(75)
JCP&L	(130)	(75)	(111)	(94)

FES’ OE's and JCP&L's shares of the net periodic pensions and OPEB costs for the three years ended December 31, 2012 were as follows:

	Pensions			OPEB		
Net Periodic Costs	2012	2011	2010	2012	2011	2010
	(In millions)					
FES	$78	$80	$80	$(11)	$(21)	$—
OE	84	79	21	(20)	(34)	(26)
JCP&L	57	70	31	4	2	(10)

3. STOCK-BASED COMPENSATION PLANS

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

LTIP

The LTIP includes four forms of stock-based compensation — restricted stock, restricted stock units, stock options and performance shares.

Under the LTIP, total awards cannot exceed 29 million shares of common stock or their equivalent. Only stock options, restricted stock and restricted stock units have currently been designated to pay out in common stock, with vesting periods ranging from two months to ten years. Performance share awards are currently designated to be paid in cash rather than common stock and therefore do not count against the limit on stock-based awards. As of December 31, 2012, five million shares were available for future awards.

FirstEnergy records the actual tax benefit realized from tax deductions when awards are exercised or distributed. Realized tax benefits during the years ended December 31, 2012, 2011 and 2010 were $22 million, $14 million and $11 million, respectively. The excess of the deductible amount over the recognized compensation cost is recorded as a component of stockholders’ equity and reported as an other financing activity on the Consolidated Statements of Cash Flows.

Restricted Stock and Restricted Stock Units

Restricted common stock (restricted stock) and restricted stock units (stock units) activity for the year ended December 31, 2012, was as follows:

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Outstanding as of January 1, 2012	2,353,134
Granted	915,891
Exercised	(907,285)
Forfeited	(181,318)
Outstanding as of December 31, 2012	2,180,422

The 915,891 shares of restricted stock granted during the year ended December 31, 2012, had a grant-date fair value of $41 million and a weighted-average vesting period of 3.03 years.

Eligible employees receive awards of FE restricted stock or stock units subject to restrictions that lapse over a defined period of time or upon achieving performance results. Dividends are received on the restricted stock and are reinvested in additional shares. Restricted stock grants under the LTIP were as follows:

	2012	2011	2010
Restricted stock granted	263,771	297,859	71,752
Weighted average market price	$44.82	$38.44	$38.43
Weighted average vesting period (years)	3.09	2.27	4.74
Dividends restricted	Yes	Yes	Yes

Vesting activity for restricted stock during 2012 was as follows (forfeitures were not material):

Restricted Stock	Number of Shares	Weighted Average Grant-Date Fair Value
Nonvested as of January 1, 2012	654,696	$45.26
Nonvested as of December 31, 2012	551,678	$47.21
Granted in 2012	263,771	$44.82
Vested in 2012	380,970	$42.75

FirstEnergy grants two types of stock unit awards: discretionary-based and performance-based. The discretionary-based awards grant the right to receive, at the end of the period of restriction, a number of shares of common stock equal to the number of stock units set forth in each agreement. Performance-based awards grant the right to receive, at the end of the period of restriction, a number of shares of common stock equal to the number of stock units set forth in the agreement subject to adjustment based on FirstEnergy's performance relative to financial and operational performance targets.

	2012	2011	2010
Restricted stock units granted	652,120	617,195	511,418
Weighted average vesting period (years)	3.00	3.00	3.00

Vesting activity for stock units during 2012 was as follows:

Restricted Stock Units	Number of Shares	Weighted Average Grant-Date Fair Value
Nonvested as of January 1, 2012	1,698,439	$39.74
Nonvested as of December 31, 2012	1,628,744	$41.10
Granted in 2012	652,120	$44.58
Forfeited in 2012	141,499	$40.39
Vested in 2012	663,954	$43.93

Compensation expense recognized in 2012, 2011 and 2010 for restricted stock and restricted stock units, net of amounts capitalized, was approximately $30 million, $35 million and $22 million, respectively. As of December 31, 2012, there was $39 million of total unrecognized compensation cost related to non-vested share-based compensation arrangements granted for restricted stock and restricted stock units; that cost is expected to be recognized over a period of approximately 2 years.

Stock Options

Stock options were granted to eligible employees allowing them to purchase a specified number of common shares at a fixed grant price over a defined period of time. Stock option activity during 2012 was as follows:

Stock Option Activity	Number of Shares	Weighted Average Exercise Price
Balance, January 1, 2012 (3,593,863 options exercisable)	4,255,985	$38.17
Options exercised	(1,327,008)	33.11
Options forfeited	(18,708)	59.58
Balance, December 31, 2012 (2,348,469 options exercisable)	2,910,269	$40.33

Options outstanding and range of exercise prices as of December 31, 2012, were as follows:

	Options Outstanding		
Range of Exercise Prices	Shares	Weighted Average Exercise Price	Remaining Contractual Life
$20.02-$28.42	136,202	$21.49	1.29
$28.43-$35.45	851,948	$33.04	3.56
$35.46-$79.11	1,657,150	$39.23	4.04
$79.12-$81.19	264,969	$80.47	4.80
Total	2,910,269	$40.33	3.84

Compensation expense recognized for stock options during 2012 and 2011 was $0.9 million and $0.8 million, respectively. No compensation expense was recognized for stock options during 2010. Cash received from the exercise of stock options in 2012, 2011 and 2010 was $50 million, $32 million and $6 million, respectively. The total intrinsic value of options exercised during 2012 was $18 million.

Performance Shares

Performance shares are share equivalents and do not have voting rights. The shares track the performance of FE's common stock over a three-year vesting period. During that time, dividend equivalents are converted into additional shares. The final account value may be adjusted based on the ranking of FE stock performance to a composite of peer companies. Compensation expense (credits) recognized for performance shares during 2012, 2011 and 2010, net of amounts capitalized, totaled approximately $3 million, $2 million and $(4) million, respectively. During 2012, 2011 and 2010, no cash was paid to settle performance shares due to the criteria not being met for the previous three-year vesting period.

ESOP

An ESOP Trust funded most of the matching contribution for FirstEnergy’s 401(k) savings plan through December 31, 2007. All employees eligible for participation in the 401(k) savings plan are covered by the ESOP.

In 2012, 2011 and 2010, shares of FE common stock were purchased on the market and contributed to participants’ accounts. Total ESOP-related compensation expenses in 2012, 2011 and 2010, net of amounts capitalized and dividends on common stock, were $23 million, $21 million and $30 million, respectively.

EDCP

Under the EDCP, covered employees can direct a portion of their compensation, including annual incentive awards and/or long-term incentive awards, into an unfunded FE stock account to receive vested stock units or into an unfunded retirement cash account. Dividends are calculated quarterly on stock units outstanding and are paid in the form of additional stock units. Upon withdrawal, stock units are converted to FE shares. Payout typically occurs three years from the date of deferral; however, an election can be made in the year prior to payout to further defer shares into a retirement stock account that will pay out in cash upon retirement. Interest is calculated on the cash allocated to the cash account and the total balance will pay out in cash upon retirement. Compensation expenses (credits) recognized on EDCP stock units, net of amounts capitalized, in 2011 and 2010 were $4 million and $(3) million, respectively. In 2012, compensation expense was insignificant.

DCPD

Under the DCPD, members of the Board of Directors can elect to allocate all or a portion of their cash retainers, meeting fees and chair fees to deferred stock or deferred cash accounts. DCPD expenses of $4 million were recognized in each of the years 2012,

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2011 and 2010. The net liability recognized for DCPD of approximately $6 million as of December 31, 2012 and December 31, 2011, respectively, is included in the caption “Retirement benefits” on the Consolidated Balance Sheets. Of the 1.7 million stock units authorized under the EDCP and DCPD, 988,713 stock units were available for future awards as of December 31, 2012.

4. TAXES

Income Taxes

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

PROVISION FOR INCOME TAXES	FirstEnergy	FES	OE	JCP&L
	(In millions)			
2012				
Currently payable (receivable)-				
Federal	$(122)	$(120)	$56	$(120)
State	28	17	(5)	(18)
	(94)	(103)	51	(138)
Deferred, net-				
Federal	580	208	8	201
State	78	10	16	44
	658	218	24	245
Investment tax credit amortization	(11)	(4)	(1)	—
Total provision for income taxes	$553	$111	$74	$107
2011				
Currently payable (receivable)-				
Federal	$(243)	$(219)	$13	$19
State	19	9	(12)	7
	(224)	(210)	1	26
Deferred, net-				
Federal	785	206	65	71
State	24	(3)	13	20
	809	203	78	91
Investment tax credit amortization	(11)	(4)	(1)	—
Total provision for income taxes	$574	$(11)	$78	$117
2010				
Currently payable (receivable)-				
Federal	$(23)	$(23)	$37	$80
State	35	(2)	(2)	36
	12	(25)	35	116
Deferred, net-				
Federal	432	142	41	30
State	27	12	3	1
	459	154	44	31
Investment tax credit amortization	(9)	(4)	(1)	—

Total provision for income taxes	$462	$125	$78	$147

In December 2012, two subsidiaries of FES, FG and NG, completed a conversion from corporations to limited liability companies (LLCs). For income tax purposes, these LLCs are treated as divisions (i.e., disregarded entities) of their parent company, FES. The LLC conversions, in combination with anticipated future taxable income, will contribute to the realization of certain state deferred tax assets. In 2011, an unregulated subsidiary of FirstEnergy converted to an LLC which, based on anticipated future taxable income, resulted in the partial reversal of a valuation allowance, reducing income tax expense in 2011 by $27 million.

A $50 million valuation allowance was established in 2012 for two unregulated subsidiaries of FirstEnergy based on current judgment as to the realization of certain state deferred tax assets, as impacted by changes in the business and the applicability of certain state law limitations on the long-term utilization of net operating loss carryforwards. The results of operations in 2012 for those companies decreased accumulated deferred income tax liabilities by approximately $50 million.

During 2012, certain FirstEnergy operating companies adopted a new federal tax accounting method (effective for the 2011 consolidated federal tax return) for the deductibility of expenses for repairs to transmission and distribution assets, pursuant to IRS safe harbor guidance. In accordance with the IRS guidance, a cumulative adjustment was made on the 2011 consolidated federal tax return, increasing tax deductions and decreasing taxable income by approximately $417 million. The increased federal tax deductions created a corresponding state tax benefit that reduced FirstEnergy's effective tax rate by approximately $12 million in 2012. The IRS has agreed that the new method of accounting is compliant with the IRS guidance.

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

In 2010, approximately $325 million of costs were included as a repair deduction on FirstEnergy's 2009 consolidated federal income tax return, which reduced taxable income and increased the amount of tax refunds that were applied to FirstEnergy's 2010 estimated federal tax payments. Due to the flow through of the Pennsylvania state income tax benefit for this change in accounting, FirstEnergy's effective tax rate was reduced by $6 million in 2010. In connection with completing FirstEnergy's 2009 consolidated tax return, FES recognized an $8 million adjustment that increased its income tax expense in 2010.

FES and the Utilities are party to an intercompany income tax allocation agreement with FirstEnergy and its other subsidiaries that provides for the allocation of consolidated tax liabilities. Net tax benefits attributable to FirstEnergy, excluding any tax benefits derived from interest expense associated with acquisition indebtedness from the merger with GPU, are reallocated to the subsidiaries of FirstEnergy that have taxable income. That allocation is accounted for as a capital contribution to the company receiving the tax benefit.

The following tables provide a reconciliation of federal income tax expense at the federal statutory rate to the total provision for income taxes for the three years ended December 31.

	FirstEnergy	FES	OE	JCP&L
	(In millions)			
2012				
Book income (loss) before provision for income taxes	$1,323	$298	$175	$240
Federal income tax expense at statutory rate	$463	$104	$61	$84
Increases (reductions) in taxes resulting from-				
Amortization of investment tax credits	(11)	(4)	(1)	—
State income taxes, net of federal tax benefit	69	18	7	17
Medicare Part D	32	1	6	5
Effectively settled tax items	(20)	(11)	(1)	—
State valuation allowance	60	—	—	—
State apportionment remeasurement	(50)	—	—	—
Other, net	10	3	2	1
Total provision for income taxes	$553	$111	$74	$107
2011				
Book income (loss) before provision for income taxes	$1,459	$(70)	$206	$261
Federal income tax expense at statutory rate	$511	$(25)	$72	$91
Increases (reductions) in taxes resulting from-				
Amortization of investment tax credits	(11)	(4)	(1)	—
State income taxes, net of federal tax benefit	28	4	1	18
State unitary tax adjustments	33	—	—	—
Manufacturing deduction	16	13	3	—
Medicare Part D	36	4	6	6
Effectively settled tax items	(11)	(2)	(3)	—
State valuation allowance	(19)	2	—	—
Other, net	(9)	(3)	—	2
Total provision for income taxes	$574	$(11)	$78	$117
2010				
Book income (loss) before provision for income taxes	$1,204	$356	$233	$330
Federal income tax expense at statutory rate	$421	$125	$82	$116
Increases (reductions) in taxes resulting from-				
Amortization of investment tax credits	(9)	(4)	(1)	—
State income taxes, net of federal tax benefit	40	7	1	24
Medicare Part D	17	1	2	4
Effectively settled tax items	(34)	(2)	(9)	—
Other, net	27	(2)	3	3
Total provision for income taxes	$462	$125	$78	$147

Accumulated deferred income taxes as of December 31, 2012 and 2011 are as follows:

	FirstEnergy	FES	OE	JCP&L
	(In millions)			
December 31, 2012				
Property basis differences	$7,868	$1,060	$728	$919
Regulatory transition charge	79	—	5	44
Customer receivables for future income taxes	130	—	9	1
Deferred MISO/PJM transmission costs	125	—	—	—
Other regulatory assets — RCP	161	—	80	—
Deferred sale and leaseback gain	(431)	(384)	(26)	(9)
Non-utility generation costs	5	—	—	(22)
Unamortized investment tax credits	(67)	(17)	(3)	(2)
Unrealized losses on derivative hedges	(21)	2	—	(1)
Pensions and OPEB	(1,102)	(105)	(108)	(106)
Lease market valuation liability	(81)	33	—	—
Oyster Creek securitization (Note 11)	75	—	—	75
Nuclear decommissioning activities	127	111	15	(22)
Mark-to-market adjustments	30	30	—	—
Deferred gain for asset sales — affiliated companies	—	—	27	—
Loss carryforwards and AMT credits	(1,199)	(221)	—	(21)
Loss carryforward valuation reserve	102	16	—	—
Storm damage	192	—	—	163
Market transition charge	65	—	—	65
All other	239	(22)	40	4
Net deferred income tax liability	$6,297	$503	$767	$1,088
December 31, 2011				
Property basis differences	$6,738	$770	$673	$792
Regulatory transition charge	105	—	30	49
Customer receivables for future income taxes	138	—	13	12
Deferred MISO/PJM transmission costs	51	—	—	—
Other regulatory assets — RCP	165	—	82	—
Deferred sale and leaseback gain	(450)	(398)	(31)	(10)
Non-utility generation costs	36	—	—	(2)
Unamortized investment tax credits	(72)	(19)	(3)	(2)
Unrealized losses on derivative hedges	(21)	5	—	(1)
Pensions and OPEB	(752)	(85)	(76)	(75)
Lease market valuation liability	(179)	(65)	—	—
Oyster Creek securitization (Note 11)	93	—	—	93
Nuclear decommissioning activities	123	108	15	(7)
Mark-to-market adjustments	(7)	(7)	—	—
Deferred gain for asset sales — affiliated companies	—	—	31	—
Loss carryforwards and ATM credits	(612)	(34)	—	—
Loss carryforward valuation reserve	34	12	—	—
Storm damage	55	—	—	42
Market transition charge	17	—	—	17
All other	208	(1)	53	(49)
Net deferred income tax liability	$5,670	$286	$787	$859

As of December 31, 2012, FirstEnergy had a current federal tax asset of approximately $319 million. The American Taxpayer Relief Act of 2012 was enacted in January 2013 (Act) and provides 50% accelerated (bonus) depreciation for qualifying expenditures made in 2013. As a result of the availability of 50% bonus depreciation for 2013, FirstEnergy anticipates that approximately $274 million of the current federal tax asset as of December 31, 2012, will not be realized in 2013 but will be available for future years. Of the $319 million current federal tax asset, approximately $12 million and $1 million is attributed to FES and JCP&L, respectively, which will be realized in future years. It is not anticipated that FES or JCP&L will realize any of this current federal tax asset in 2013.

FirstEnergy accounts for uncertainty in income taxes recognized in its financial statements. Accounting guidance prescribes a recognition threshold and measurement attribute for financial statement recognition and measurement of tax positions taken or expected to be taken on a company's tax return. As of December 31, 2011 and 2012, FirstEnergy's total unrecognized income tax benefits were approximately $117 million and $43 million, respectively. All $43 million of unrecognized income tax benefits as of December 31, 2012, would impact the effective tax rate if ultimately recognized in future years. As of December 31, 2012, it is reasonably possible that approximately $4 million of unrecognized tax benefits may be resolved during 2013, all of which would affect FirstEnergy’s effective tax rate.

During the fourth quarter of 2012, FirstEnergy reached a settlement with the IRS on deductions for prior year costs to repair generation assets, permitting the reduction of unrecognized tax benefits by approximately $34 million, with a corresponding adjustment to accumulated deferred income taxes for this temporary tax item, and an overall decrease to FirstEnergy's effective tax rate of approximately $10 million for adjustments to potential interest expense resulting from the settlement. Also during the fourth quarter of 2012, the AE companies reduced reserves for unrecognized tax benefits related to various tax positions, including the IRS's agreement on AE's deduction of merger-related expenses, with a total reduction to the effective tax rate of approximately $7 million.

During 2012, FirstEnergy also submitted a claim for refund to the IRS for up to approximately $1.7 billion of additional accelerated (bonus) depreciation deductions for certain generation property for the 2010 taxable year, which should have an immaterial impact on earnings. The refund claim is under IRS examination. During 2012, FirstEnergy reached a settlement with state authorities related to state apportionment factors in Pennsylvania on an intercompany asset sale, which reduced FirstEnergy's effective tax rate by $3 million. During 2012, based on further IRS guidance related to the tax accounting for costs to repair and maintain fixed assets, the AE companies reduced their amount of unrecognized tax benefits by $21 million, with a corresponding adjustment to accumulated deferred income taxes for this temporary tax item, with no resulting impact to the effective tax rate.

In 2011, FirstEnergy reached a settlement with the IRS on an R&D claim and recognized approximately $30 million of income tax benefits, including $5 million that favorably affected FirstEnergy's effective tax rate in 2011. After reaching settlements on appeal in 2010 related primarily to the capitalization of certain costs for the tax years 2004-2008 and an unrelated federal tax matter related to prior year gains and losses recognized from the disposition of assets, as well as receiving final approval from the Joint Committee on Taxation for several items that were under appeal for tax years 2001-2003, FirstEnergy recognized approximately $78 million of net tax benefits in 2010, including $21 million that favorably affected FirstEnergy’s effective tax rate. The remaining portion of the tax benefit increased FirstEnergy’s accumulated deferred income taxes.

The following table summarizes the changes in unrecognized tax positions for the years ended 2012, 2011 and 2010.

	FirstEnergy	FES	OE	JCP&L
	(In millions)			
Balance, January 1, 2010	$191	$41	$77	$14
Current year increases	10	6	2	—
Prior years increases	2	—	—	—
Prior years decreases	(81)	(4)	(19)	(21)
Increase (decrease) for settlements	(77)	(2)	(58)	7
Balance, December 31, 2010	$45	$41	$2	$—
Increase due to merger with AE	97	—	—	—
Prior years increases	10	8	—	—
Prior years decreases	(35)	(4)	(2)	—
Balance, December 31, 2011	$117	$45	$—	$—
Current year increases	2	—	—	—
Current year decreases	(7)	—	—	—
Prior years increases	6	6	—	—
Prior years decreases	(37)	(13)	—	—
Decrease for settlements	(38)	(35)	—	—

Balance, December 31, 2012	$43	$3	$—	$—

FirstEnergy recognizes interest expense or income related to uncertain tax positions. That amount is computed by applying the applicable statutory interest rate to the difference between the tax position recognized and the amount previously taken or expected to be taken on the federal income tax return. FirstEnergy includes net interest and penalties in the provision for income taxes. During 2012, FirstEnergy's reversal of accrued interest associated with unrecognized tax benefits reduced FirstEnergy's effective tax rate by approximately $4 million. The interest associated with the 2011 settlement of a claim favorably affected FirstEnergy's effective tax rate by $7 million in 2011. The reversal of accrued interest associated with the recognized tax benefits reduced FirstEnergy's effective tax rate by $12 million in 2010.

The following table summarizes the net interest expense (income) for the three years ended December 31st and the cumulative net interest payable (receivable) as of December 31, 2012 and 2011:

	Net Interest Expense (Income) For the Years Ended December 31,			Net Interest Payable As of December 31,	
	2012	2011	2010	2012	2011
	(In millions)			(In millions)	
FirstEnergy	$(4)	$(5)	$(10)	$8	$11
FES	(4)	1	1	—	4
OE	(1)	(2)	(3)	—	1
JCP&L	—	—	(2)	—	—

FirstEnergy has tax returns that are under review at the audit or appeals level by the IRS (2008-2012) and state tax authorities. FirstEnergy's tax returns for all state jurisdictions are open from 2008-2011. The IRS completed its audit of the 2008 tax year in July 2010, and FirstEnergy subsequently reached a tentative settlement with IRS Appeals on one outstanding issue in December 2012. The IRS's audits of the 2009 and 2010 tax years were completed in April 2011 and July 2012, respectively. Tax years 2011-2012 are under review by the IRS. AE is currently under audit by the IRS for tax years 2009 and 2010. In September 2012, the AE group of companies filed a final federal tax return for the period January-February 2011, which is subject to review. For the remainder of the 2011 taxable year and future years, the AE companies are part of the FirstEnergy federal consolidated group. State tax returns for tax years 2009 through 2011 remain subject to review in Pennsylvania, West Virginia, Maryland and Virginia for certain subsidiaries of AE.

FirstEnergy has recorded as deferred income tax assets the effect of net operating losses and tax credits that will more likely than not be realized through future operations and through the reversal of existing temporary differences. As of December 31, 2012, the deferred income tax assets, before any valuation allowances, consisted of $785 million of federal net operating loss carryforwards that expire from 2024 to 2032, federal AMT credits of $25 million that have an indefinite carryforward period, and $389 million of state and local net operating loss carryforwards that begin to expire in 2013.

The table below summarizes pre-tax net operating loss carryforwards for state and local income tax purposes of approximately $15.8 billion for FirstEnergy, of which approximately $13.7 billion is expected to be utilized based on current estimates and assumptions. The ultimate utilization of these net operating losses may be impacted by statutory limitations on the use of net operating losses imposed by state and local tax jurisdictions, changes in statutory tax rates, and changes in business which, among other things, impact both future profitability and the manner in which future taxable income is apportioned to various state and local tax jurisdictions.

Expiration Period	FirstEnergy		FES	
	(In millions)			
	State	Local	State	Local
2013-2017	$9	$1,665	$—	$904
2018-2022	2,907	—	43	—
2023-2027	6,505	—	45	—
2028-2032	4,728	—	746	—
	$14,149	$1,665	$834	$904

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General Taxes

	FirstEnergy (In millions)	FES	OE	JCP&L
2012				
KWH excise	$230	$—	$88	$37
State gross receipts	251	77	15	—
Real and personal property	329	35	80	6
Social security and unemployment	126	20	10	12
Other	49	4	—	—
Total general taxes	$985	$136	$193	$55
2011				
KWH excise	$244	$—	$90	$50
State gross receipts	264	62	17	—
Real and personal property	299	42	73	6
Social security and unemployment	109	14	9	11
Other	62	6	1	—
Total general taxes	$978	$124	$190	$67
2010				
KWH excise	$245	$5	$92	$51
State gross receipts	185	17	15	—
Real and personal property	243	53	67	5
Social security and unemployment	86	14	8	9
Other	17	5	1	—
Total general taxes	$776	$94	$183	$65

5. LEASES

FirstEnergy leases certain generating facilities, office space and other property and equipment under cancelable and noncancelable leases.

In 1987, OE sold portions of its ownership interests in Perry Unit 1 and Beaver Valley Unit 2 and entered into operating leases on the portions sold for basic lease terms of approximately 29 years. In that same year, CEI and TE also sold portions of their ownership interests in Beaver Valley Unit 2 and Bruce Mansfield Units 1, 2 and 3 and entered into similar operating leases for lease terms of approximately 30 years. During the terms of their respective leases, OE, CEI and TE are responsible, to the extent of their leasehold interests, for costs associated with the units including construction expenditures, operation and maintenance expenses, insurance, nuclear fuel, property taxes and decommissioning. They have the right, at the expiration of the respective basic lease terms, to renew their respective leases. They also have the right to purchase the facilities at the expiration of the basic lease term or any renewal term at a price equal to the fair market value of the facilities. The basic rental payments are adjusted when applicable federal tax law changes.

In 2007, CEI and TE assigned their leasehold interests in the Bruce Mansfield Plant to FG, who assumed all of CEI's and TE's obligations arising under those leases. However, CEI and TE remain primarily liable on those 1987 leases and related agreements for which the EBO has not been completed totaling 321.2 MWs. FG remains primarily liable on the 2007 leases and related agreements, and FES remains primarily liable as a guarantor under the related 2007 guarantees, as to the lessors and other parties to the respective agreements. These assignments terminate automatically upon the termination of the underlying leases.

In 2007, FG completed a sale and leaseback transaction for its 93.825% undivided interest in Bruce Mansfield Unit 1 and entered into operating leases for basic lease terms of approximately 33 years. FES has unconditionally and irrevocably guaranteed all of FG's obligations under each of the leases.

During 2008, NG purchased 56.8 MW of lessor equity interests in the OE 1987 sale and leaseback of the Perry Plant and approximately 43.5 MW of lessor equity interests in the OE 1987 sale and leaseback of Beaver Valley Unit 2. In addition, NG purchased 158.5 MW of lessor equity interests in the TE and CEI 1987 sale and leaseback of Beaver

Valley Unit 2. The Ohio Companies continue to lease these MW under their respective sale and leaseback arrangements and the related lease debt remains outstanding.

During 2012, NG repurchased 70.1 MW of lessor equity interests in OE's existing sale and leaseback of Beaver Valley Unit 2 for $129 million and FG acquired 441.9 MW of certain equity or other interests in connection with the 1987 Bruce Mansfield Plant sale and leaseback transactions for $262.2 million.

Rentals for capital and operating leases for 2012, 2011 and 2010, are summarized as follows:

	FirstEnergy	FES	OE	JCP&L
	(In millions)			
2012				
Operating leases	$307	$243	$147	$8
Capital leases				
Interest element	5	1	—	—
Other	52	36	2	—
Total rentals	$364	$280	$149	$8
2011				
Operating leases	$226	$197	$147	$8
Capital leases				
Interest element	6	1	—	—
Other	46	34	—	—
Total rentals	$278	$232	$147	$8
2010				
Operating leases	$228	$202	$147	$9
Capital leases				
Interest element	2	1	—	—
Other	35	34	—	—
Total rentals	$265	$237	$147	$9

The future minimum capital lease payments as of December 31, 2012 are as follows (JCP&L has no material capital leases):

Capital leases	FirstEnergy	FES	OE
	(In millions)		
2013	$36	$6	$4
2014	35	6	4
2015	32	6	4
2016	29	5	4
2017	24	5	4
Years thereafter	55	2	13
Total minimum lease payments	211	30	33
Interest portion	(35)	(3)	(4)
Present value of net minimum lease payments	176	27	29
Less current portion	32	5	3
Noncurrent portion	$144	$22	$26

Established by OE in 1996, PNBV purchased a portion of the lease obligation bonds issued on behalf of lessors in OE’s Perry Unit 1 and Beaver Valley Unit 2 sale and leaseback transactions. Similarly, CEI and TE established Shippingport in 1997 to purchase the lease obligation bonds issued on behalf of lessors in their Bruce Mansfield Units 1, 2 and 3 sale and leaseback transactions. The PNBV and Shippingport arrangements effectively reduce lease costs related to those transactions (see Note 7, Variable Interest Entities).

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FirstEnergy's future minimum consolidated operating lease payments as of December 31, 2012, are as follows:

Operating Leases	FirstEnergy Lease Payments	Capital Trust	Net
	(In millions)		
2013	$256	$46	$210
2014	250	48	202
2015	246	40	206
2016	214	13	201
2017	126	3	123
Years thereafter	1,678	—	1,678
Total minimum lease payments	$2,770	$150	$2,620

FES', OE's and JCP&L's future minimum operating lease payments as of December 31, 2012, are as follows:

Operating Leases	FES	OE(1)	JCP&L
	(In millions)		
2013	$144	$146	$9
2014	143	145	8
2015	141	145	7
2016	130	116	8
2017	81	46	7
Years thereafter	1,581	3	52
Total minimum lease payments	$2,220	$601	$91

(1) Includes certain minimum lease payments associated with NG's lessor equity interests in Perry and Beaver Valley Unit 2 that are eliminated in consolidation.

FirstEnergy recorded above-market lease liabilities for Beaver Valley Unit 2 and the Bruce Mansfield Plant associated with the 1997 merger between OE and Centerior.

6. INTANGIBLE ASSETS

As of December 31, 2012, intangible assets classified in Other Deferred Charges on FirstEnergy's Consolidated Balance Sheet, including those recorded in connection with the Allegheny merger, include the following:

	Intangible Assets			Amortization expense						
				Actual	Estimated					
(In millions)	Gross	Accumulated Amortization	Net	2012	2013	2014	2015	2016	2017	Thereafter
NUG contracts(1)(2)	$124	$9	$115	$5	$5	$5	$5	$5	$5	$90
OVEC(1)	54	3	51	2	2	2	2	2	2	41
Coal contracts(1)(3)	556	145	411	55	59	58	51	51	45	79
FES customer contracts	146	36	110	15	16	17	17	17	16	27
Energy contracts(1)	136	121	15	50	14	1	—	—	—	—
	$1,016	$314	$702	$127	$96	$83	$75	$75	$68	$237

(1) Fair value measurements of intangible assets recorded in connection with the Allegheny merger (see Note 19, Merger).

(2) NUG contracts are subject to regulatory accounting and their amortization does not impact earnings.

(3) A gross amount of $102 million ($68 million, net) of the coal contracts was recorded with a regulatory offset and the amortization does not impact earnings.

FES acquired certain customer contract rights which were capitalized as intangible assets. These rights allow FES to supply electric generation to customers, and the recorded value is being amortized ratably over the term of the related contracts.

7. VARIABLE INTEREST ENTITIES

FirstEnergy performs qualitative analyses to determine whether a variable interest gives FirstEnergy a controlling financial interest in a VIE. This analysis identifies the primary beneficiary of a VIE as the enterprise that has both the power to direct the activities of a VIE that most significantly impact the entity’s economic performance and the obligation to absorb losses of the entity that could

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potentially be significant to the VIE or the right to receive benefits from the entity that could potentially be significant to the VIE. FE and its subsidiaries consolidate a VIE when it is determined that it is the primary beneficiary.

VIEs included in FirstEnergy’s consolidated financial statements are: FEV's joint venture in the Signal Peak mining and coal transportation operations, a portion of which was sold on October 18, 2011, and resulted in deconsolidation; the PNBV and Shippingport capital trusts that were created to refinance debt originally issued in connection with sale and leaseback transactions; wholly owned limited liability companies of JCP&L created to sell transition bonds to securitize the recovery of JCP&L’s bondable stranded costs associated with the previously divested Oyster Creek Nuclear Generating Station and JCP&L's supply of BGS, of which $243 million was outstanding as of December 31, 2012; and special purpose limited liability companies created to issue environmental control bonds that were used to construct environmental control facilities, of which $493 million was outstanding as of December 31, 2012.

The caption "noncontrolling interest" within the consolidated financial statements is used to reflect the portion of a VIE that FirstEnergy consolidates, but does not own. The change in noncontrolling interest within the Consolidated Balance Sheets during the year ended December 31, 2012, was primarily due to net income attributable to noncontrolling interests of $1 million, offset by $11 million in distributions to owners.

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

Mining Operations

In 2008, FEV entered into a joint venture in the Signal Peak mining and coal transportation operations near Roundup, Montana. FEV made equity investments totaling $134 million in exchange for a 50% economic interest in the joint venture. On October 18, 2011, Pinesdale LLC, a subsidiary of Gunvor Group, Ltd., purchased a one-third interest in the Signal Peak joint venture in which FEV held a 50% interest. As part of the transaction, FirstEnergy received $258 million in proceeds and retained a 33-1/3% equity ownership in Global Holding, the holding company for the joint venture. The sale resulted in a pre-tax gain of approximately $569 million ($370 million after-tax), which included $379 million from the remeasurement of FEV's retained investment. The gain attributed to the retained investment remeasurement is being amortized as coal is extracted from the mine on a units of production method.

Prior to the sale, FirstEnergy consolidated this joint venture since FEV was determined to be the primary beneficiary of the VIE. As a result of the sale, FEV was no longer determined to be the primary beneficiary and its retained 33-1/3% interest is subject to the equity method of accounting.

Trusts

FirstEnergy's consolidated financial statements include PNBV and Shippingport - the PNBV trust is included in the consolidated financial statements of OE. FirstEnergy's subsidiaries used debt and available funds to purchase the notes issued by PNBV and Shippingport for the purchase of lease obligation bonds. Ownership of PNBV includes a 3% equity interest by an unaffiliated third party and a 3% equity interest held by OES Ventures, a wholly owned subsidiary of OE.

PATH-WV

PATH is a series limited liability company that is comprised of multiple series, each of which has separate rights, powers and duties regarding specified property and the series profits and losses associated with such property. A subsidiary of AE owns 100% of the Allegheny Series (PATH-Allegheny) and 50% of the West Virginia Series (PATH-WV), which is a joint venture with a subsidiary of AEP. FirstEnergy is not the primary beneficiary of PATH-WV, as it does not have control over the significant activities affecting the economics of the portion of the PATH project that was to be constructed by PATH-WV.

On August 24, 2012, PJM removed the PATH project from its long-range expansion plans. See Note 14, Regulatory Matters, for additional information on the abandonment of PATH.

Power Purchase Agreements

FirstEnergy evaluated its power purchase agreements and determined that certain NUG entities may be VIEs to the extent that they own a plant that sells substantially all of its output to the applicable utilities and the contract price for power is correlated with the plant’s variable costs of production. FirstEnergy, through JCP&L and other subsidiaries, maintains 20 long-term power purchase agreements with NUG entities that were entered into pursuant to PURPA.

FirstEnergy was not involved in the creation of, and has no equity or debt invested in, any of these entities. FirstEnergy has determined that for all but three of these NUG entities, its subsidiaries do not have variable interests in the entities or the entities do not meet the criteria to be considered a VIE. JCP&L and other subsidiaries may hold variable interests in the remaining three entities; however, FirstEnergy applied the scope exception that exempts enterprises unable to obtain the necessary information to evaluate entities.

Because JCP&L, and other FirstEnergy subsidiaries have no equity or debt interests in the NUG entities, their maximum exposure to loss relates primarily to the above-market costs incurred for power. FirstEnergy expects any above-market costs incurred by its subsidiaries to be recovered from customers, except as described further below. Purchased power costs related to the three contracts that may contain a variable interest that were held by FE subsidiaries during the year ended December 31, 2012, were $67 million and $186 million for JCP&L and other subsidiaries, respectively. Purchased power costs related to the four contracts that may contain a variable interest that were held by JCP&L and other subsidiaries during the year ended December 31, 2011, were $176 million and $151 million, respectively. Purchased power costs related to the two contracts that may contain a variable interest that were held by JCP&L during the year ended December 31, 2010 were $243 million.

In 1998 the PPUC issued an order approving a transition plan for WP that disallowed certain costs, including an estimated amount for an adverse power purchase commitment related to the NUG entity wherein WP may hold a variable interest, for which WP has taken the scope exception. On November 20, 2012, WP entered into an agreement to terminate the adverse power purchase commitment and accrued a pre-tax loss of $17 million. WP terminated the adverse commitment on January 1, 2013. WP's liability for this adverse purchase power commitment was $60 million, which includes the $17 million accrual.

Loss Contingencies

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

During 2012, NG repurchased lessor equity interests in OE's existing sale and leaseback of Beaver Valley Unit 2 for $129 million and FG acquired certain equity or other interests in connection with the 1987 Bruce Mansfield Plant sale and leaseback transactions for $262.2 million.

FES, OE and other FE subsidiaries are exposed to losses under their applicable sale and leaseback agreements upon the occurrence of certain contingent events. The maximum exposure under these provisions represents the net amount of casualty value payments due upon the occurrence of specified casualty events. Net discounted lease payments would not be payable if the casualty loss payments were made. The following table discloses each company’s net exposure to loss based upon the casualty value provisions as of December 31, 2012:

	Maximum Exposure	Discounted Lease Payments, net(1)	Net Exposure
	(In millions)		
FES	$1,324	$1,113	$211
OE	545	353	192
Other FE subsidiaries	303	263	40

(1) The net present value of FirstEnergy’s consolidated sale and leaseback operating lease commitments is $1.2 billion.

8. FAIR VALUE MEASUREMENTS

RECURRING AND NONRECURRING FAIR VALUE MEASUREMENTS

On January 1, 2012, FirstEnergy adopted an amendment to the authoritative accounting guidance regarding fair value measurements. The amendment was applied prospectively and expanded disclosure requirements for fair value measurements, particularly for Level 3 measurements, among other changes.

Authoritative accounting guidance establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. This hierarchy gives the highest priority to Level 1 measurements and the lowest priority to Level 3 measurements. The three levels of the fair value hierarchy and a description of the valuation techniques are as follows:

Level 1 - Quoted prices for identical instruments in active market

Level 2 - Quoted prices for similar instruments in active market
- Quoted prices for identical or similar instruments in markets that are not active

- Model-derived valuations for which all significant inputs are observable market data

Models are primarily industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors and current market and contractual prices for the underlying instruments, as well as other relevant economic measures.

Level 3 - Valuation inputs are unobservable and significant to the fair value measurement

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FirstEnergy produces a long-term power and capacity price forecast annually with periodic updates as market conditions change. When underlying prices are not observable, prices from the long-term price forecast, which has been reviewed and approved by FirstEnergy's Risk Policy Committee, are used to measure fair value. A more detailed description of FirstEnergy's valuation process for FTRs, NUGs and LCAPPs are as follows:

FTRs are financial instruments that entitle the holder to a stream of revenues (or charges) based on the hourly day-ahead congestion price differences across transmission paths. FTRs are acquired by FirstEnergy in the annual, monthly and long-term RTO auctions and are initially recorded using the auction clearing price less cost. After initial recognition, FTRs' carrying values are periodically adjusted to fair value using a mark-to-model methodology, which approximates market. The primary inputs into the model, which are generally less observable from objective sources, are the most recent RTO auction clearing prices and the FTRs' remaining hours. The model calculates the fair value by multiplying the most recent auction clearing price by the remaining FTR hours less the prorated FTR cost. Generally, significant increases or decreases in inputs in isolation could result in a higher or lower fair value measurement. See Note 9, Derivative Instruments, for additional information regarding FirstEnergy's FTRs.

NUG contracts represent purchased power agreements with third-party non-utility generators that are transacted to satisfy certain obligations under PURPA. NUG contract carrying values are recorded at fair value and adjusted periodically using a mark-to-model methodology, which approximates market. The primary unobservable inputs into the model are regional power prices and generation MWH. Pricing for the NUG contracts is a combination of market prices for the current year and next three years based on observable data and internal models using historical trends and market data for the remaining years under contract. The internal models use forecasted energy purchase prices as an input when prices are not defined by the contract. Forecasted market prices are based on ICE quotes and management assumptions. Generation MWH reflects data provided by contractual arrangements and historical trends. The model calculates the fair value by multiplying the prices by the generation MWH. Generally, significant increases or decreases in inputs in isolation could result in a higher or lower fair value measurement.

LCAPP contracts are financially settled agreements that allow eligible generators to receive payments from, or make payments to, JCP&L pursuant to an annually calculated load-ratio share of the capacity produced by the generator based upon the annual forecasted peak demand as determined by PJM. LCAPP contracts are recorded at fair value and adjusted periodically using a mark-to-model methodology, which approximates market. The primary unobservable input into the model is forecasted regional capacity prices. Pricing for the LCAPP contracts is a combination of PJM RPM capacity auction prices for the 2015/2016 delivery year and internal models using historical trends and market data for the remaining years under contract. Capacity prices beyond the 2015/2016 delivery year are developed through a simulation of future PJM RPM auctions. The capacity price forecast assumes a continuation of the current PJM RPM market design and is reflective of the regional peak demand growth and generation fleet additions and retirements that underlie FirstEnergy’s long-term energy price forecast. Generally, significant increases or decreases in inputs in isolation could result in a higher or lower fair value measurement.
FirstEnergy primarily applies the market approach for recurring fair value measurements using the best information available. Accordingly, FirstEnergy maximizes the use of observable inputs and minimizes the use of unobservable inputs. There were no changes in valuation methodologies used as of December 31, 2012, from those used as of December 31, 2011. The determination of the fair value measures takes into consideration various factors, including but not limited to, nonperformance risk, counterparty credit risk and the impact of credit enhancements (such as cash deposits, LOCs and priority interests). The impact of these forms of risk was not significant to the fair value measurements.

Transfers between levels are recognized at the end of the reporting period. There were no transfers between levels during the year ended December 31, 2012. The following tables set forth the recurring assets and liabilities that are accounted for at fair value by level within the fair value hierarchy:
FirstEnergy

Recurring Fair Value Measurements	December 31, 2012				December 31, 2011			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets	(In millions)							
Corporate debt securities	$—	$1,259	$—	$1,259	$—	$1,544	$—	$1,544
Derivative assets - commodity contracts	—	252	—	252	—	264	—	264
Derivative assets - FTRs	—	—	8	8	—	—	1	1
Derivative assets - NUG contracts(1)	—	—	36	36	—	—	56	56
Equity securities(2)	310	—	—	310	259	—	—	259
Foreign government debt securities	—	126	—	126	—	3	—	3
U.S. government debt securities	—	179	—	179	—	148	—	148
U.S. state debt securities	—	299	—	299	—	314	—	314
Other(3)	126	227	—	353	49	225	—	274
Total assets	$436	$2,342	$44	$2,822	$308	$2,498	$57	$2,863
Liabilities								
Derivative liabilities - commodity contracts	$(3)	$(151)	$—	$(154)	$—	$(247)	$—	$(247)
Derivative liabilities - FTRs	—	—	(9)	(9)	—	—	(23)	(23)
Derivative liabilities - NUG contracts(1)	—	—	(290)	(290)	—	—	(349)	(349)
Derivative liabilities - LCAPP contracts(1)	—	—	(144)	(144)	—	—	—	—
Total liabilities	$(3)	$(151)	$(443)	$(597)	$—	$(247)	$(372)	$(619)
Net assets (liabilities)(4)	$433	$2,191	$(399)	$2,225	$308	$2,251	$(315)	$2,244

(1) NUG and LCAPP contracts are generally subject to regulatory accounting treatment and do not impact earnings.
(2) NDT funds hold equity portfolios whose performance is benchmarked against the Alerian MLP Index.
(3) Primarily consists of short-term cash investments.
(4) Excludes $110 million and $(52) million as of December 31, 2012 and December 31, 2011, respectively, of receivables, payables, taxes and accrued income associated with financial instruments reflected within the fair value table.

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Rollforward of Level 3 Measurements

The following table provides a reconciliation of changes in the fair value of NUG and LCAPP contracts and FTRs that are classified as Level 3 in the fair value hierarchy for the periods ended December 31, 2012 and December 31, 2011:

	NUG Contracts[1]			LCAPP Contracts[1]			FTRs		
	Derivative Assets (in millions)	Derivative Liabilities	Net	Derivative Assets	Derivative Liabilities	Net	Derivative Assets	Derivative Liabilities	Net
January 1, 2011 Balance	$122	$(466)	$(344)	$—	$—	$—	$—	$—	$—
Unrealized gain (loss)	(58)	(144)	(202)	—	—	—	2	(27)	(25)
Purchases	—	—	—	—	—	—	13	(4)	9
Settlements	(7)	261	254	—	—	—	(14)	20	6
Transfers out of Level 3	—	—	—	—	—	—	—	(12)	(12)
December 31, 2011 Balance	$57	$(349)	$(292)	$—	$—	$—	$1	$(23)	$(22)
Unrealized gain (loss)	(20)	(180)	(200)	—	1	1	6	(6)	—
Purchases	—	—	—	—	(145)	(145)	13	(10)	3
Settlements	(1)	239	238	—	—	—	(12)	30	18
December 31, 2012 Balance	$36	$(290)	$(254)	$—	$(144)	$(144)	$8	$(9)	$(1)

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

Level 3 Quantitative Information

The following table provides quantitative information for FTRs, NUG contracts and LCAPP contracts that are classified as Level 3 in the fair value hierarchy for the period ended December 31, 2012:

	Fair Value as of December 31, 2012 (In millions)	Valuation Technique	Significant Input	Range	Weighted Average	Units
FTRs	$(1)	Model	RTO auction clearing prices	($3.20) to $6.30	$0.50	Dollars/MWH
NUG Contracts	$(254)	Model	Generation Electricity regional prices	700 to 6,525,000 $50.00 to $57.30	1,920,000 $53.90	MWH Dollars/MWH
LCAPP Contracts	$(144)	Model	Regional capacity prices	$158.60 to $197.30	$174.50	Dollars/MW-Day

FES

Recurring Fair Value Measurements	December 31, 2012				December 31, 2011			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets	(In millions)							
Corporate debt securities	$—	$703	$—	$703	$—	$1,010	$—	$1,010
Derivative assets - commodity contracts	—	252	—	252	—	248	—	248
Derivative assets - FTRs	—	—	6	6	—	—	1	1
Equity securities(1)	294	—	—	294	124	—	—	124
Foreign government debt securities	—	61	—	61	—	3	—	3
U.S. government debt securities	—	27	—	27	—	7	—	7
U.S. state debt securities	—	—	—	—	—	5	—	5
Other(2)	—	104	—	104	—	132	—	132
Total assets	$294	$1,147	$6	$1,447	$124	$1,405	$1	$1,530
Liabilities								
Derivative liabilities - commodity contracts	$(3)	$(151)	$—	$(154)	$—	$(234)	$—	$(234)
Derivative liabilities - FTRs	—	—	(6)	(6)	—	—	(7)	(7)
Total liabilities	$(3)	$(151)	$(6)	$(160)	$—	$(234)	$(7)	$(241)
Net assets (liabilities)(3)	$291	$996	$—	$1,287	$124	$1,171	$(6)	$1,289

(1) NDT funds hold equity portfolios whose performance is benchmarked against the Alerian MLP Index.

(2) Primarily consists of short-term cash investments.

(3) Excludes $94 million and $(58) million as of December 31, 2012 and December 31, 2011, respectively, of receivables, payables, taxes and accrued income associated with the financial instruments reflected within the fair value table.

Rollforward of Level 3 Measurements

The following table provides a reconciliation of changes in the fair value of FTRs held by FES and classified as Level 3 in the fair value hierarchy for the periods ended December 31, 2012 and December 31, 2011:

	Derivative Asset FTRs	Derivative Liability FTRs	Net FTRs
	(In millions)		
January 1, 2011 Balance	$—	$—	$—
Unrealized gain (loss)	4	(8)	(4)
Purchases	2	(1)	1
Settlements	(5)	2	(3)
December 31, 2011 Balance	$1	$(7)	$(6)
Unrealized gain (loss)	4	(4)	—
Purchases	9	(7)	2
Settlements	(8)	12	4
December 31, 2012 Balance	$6	$(6)	$—

Level 3 Quantitative Information

The following table provides quantitative information for FTRs held by FES that are classified as Level 3 in the fair value hierarchy for the period ended December 31, 2012:

	Fair Value as of December 31, 2012 (In millions)	Valuation Technique	Significant Input	Range	Weighted Average	Units
FTRs	$—	Model	RTO auction clearing prices	($3.20) to $6.30	$0.30	Dollars/MWH

OE

Recurring Fair Value Measurements	December 31, 2012				December 31, 2011			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets	(In millions)							
Corporate debt securities	$—	$—	$—	$—	$—	$3	$—	$3
U.S. government debt securities	—	137	—	137	—	132	—	132
Other(1)	—	4	—	4	—	2	—	2
Total assets(2)	$—	$141	$—	$141	$—	$137	$—	$137

(1) Primarily consists of short-term cash investments.

(2) Excludes $1 million as of December 31, 2012 and 2011, of receivables, payables, taxes and accrued income associated with the financial instruments reflected within the fair value table.

JCP&L

Recurring Fair Value Measurements	December 31, 2012				December 31, 2011			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets	(In millions)							
Corporate debt securities	$—	$142	$—	$142	$—	$144	$—	$144
Derivative assets - NUG contracts(1)	—	—	1	1	—	—	4	4
Equity securities(2)	—	—	—	—	30	—	—	30
Foreign government debt securities	—	17	—	17	—	—	—	—
U.S. government debt securities	—	5	—	5	—	2	—	2
U.S. state debt securities	—	232	—	232	—	219	—	219
Other(3)	—	32	—	32	—	15	—	15
Total assets	—	428	1	429	30	380	4	414
Liabilities								
Derivative liabilities - NUG contracts(1)	—	—	(121)	(121)	—	—	(147)	(147)
Derivative liabilities - LCAPP contracts(1)	—	—	(144)	(144)	—	—	—	—
Total liabilities	—	—	(265)	(265)	—	—	(147)	(147)
Net assets (liabilities)(4)	$—	$428	$(264)	$164	$30	$380	$(143)	$267

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

(2) NDT funds hold equity portfolios whose performance is benchmarked against the Alerian MLP Index.

(3) Primarily consists of short-term cash investments.

(4) Excludes $3 million and $2 million as of December 31, 2012 and December 31, 2011, respectively, of receivables, payables, taxes and accrued income associated with the financial instruments reflected within the fair value table.

Rollforward of Level 3 Measurements

The following table provides a reconciliation of changes in the fair value of NUG and LCAPP contracts held by JCP&L and classified as Level 3 in the fair value hierarchy for the periods ended December 31, 2012 and December 31, 2011:

	NUG Contracts[(1)]			LCAPP Contracts[(1)]		
	Derivative Assets	Derivative Liabilities	Net	Derivative Assets	Derivative Liabilities	Net
	(in millions)					
January 1, 2011 Balance	$6	$(233)	$(227)	$—	$—	$—
Unrealized loss	(2)	(11)	(13)	—	—	—
Settlements	—	97	97	—	—	—
December 31, 2011 Balance	$4	$(147)	$(143)	$—	$—	$—
Unrealized gain (loss)	(3)	(27)	(30)	—	1	1
Purchases	—	—	—	—	(145)	(145)
Settlements	—	53	53	—	—	—
December 31, 2012 Balance	$1	$(121)	$(120)	$—	$(144)	$(144)

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

Level 3 Quantitative Information

The following table provides quantitative information for NUG and LCAPP contracts held by JCP&L that are classified as Level 3 in the fair value hierarchy for the period ended December 31, 2012:

	Fair Value as of December 31, 2012 (In millions)	Valuation Technique	Significant Input	Range	Weighted Average	Units
NUG Contracts	$(120)	Model	Generation Electricity regional prices	76,000 to 1,417,000 $52.20 to $59.50	257,000 $56.10	MWH Dollars/MWH
LCAPP Contracts	$(144)	Model	Regional capacity prices	$158.60 to $197.30	$174.50	Dollars/MW-Day

INVESTMENTS

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

At the end of each reporting period, FirstEnergy evaluates its investments for OTTI. Investments classified as available-for-sale securities are evaluated to determine whether a decline in fair value below the cost basis is other than temporary. FirstEnergy first considers its intent and ability to hold an equity security until recovery and then considers, among other factors, the duration and the extent to which the security's fair value has been less than its cost and the near-term financial prospects of the security issuer when evaluating an investment for impairment. For debt securities, FirstEnergy considers its intent to hold the securities, the likelihood that it will be required to sell the securities before recovery of its cost basis and the likelihood of recovery of the securities' entire amortized cost basis. If the decline in fair value is determined to be other than temporary, the cost basis of the securities is written down to fair value.

Unrealized gains and losses on available-for-sale securities are recognized in OCI. However, unrealized losses held in the NDTs of FES and OE are recognized in earnings since the trust arrangements, as they are currently defined, do not meet the required ability and intent to hold criteria in consideration of OTTI. The NDTs of JCP&L are subject to regulatory accounting, and therefore, net unrealized gains and losses are recorded as regulatory assets or liabilities because the difference between investments held in the trust and the decommissioning liabilities is expected to be recovered from or refunded to customers.

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

Available-For-Sale Securities

FES, OE and JCP&L hold debt and equity securities within their NDT, nuclear fuel disposal and NUG trusts. These trust investments are considered available-for-sale securities, recognized at fair market value. FES, OE and JCP&L have no securities held for trading purposes.

The following table summarizes the amortized cost basis, unrealized gains (there were no unrealized losses) and fair values of investments held in NDT, nuclear fuel disposal and NUG trusts as of December 31, 2012 and December 31, 2011:

	December 31, 2012[1]			December 31, 2011[2]		
	Cost Basis	Unrealized Gains	Fair Value	Cost Basis	Unrealized Gains	Fair Value
	(In millions)					
Debt securities						
FirstEnergy	$1,827	$34	$1,861	$1,980	$25	$2,005
FES	778	14	792	1,012	13	1,025
OE	137	—	137	134	—	134
JCP&L	382	11	393	356	7	363
Equity securities						
FirstEnergy	$293	$16	$309	$222	$36	$258
FES	281	13	294	104	20	124
JCP&L	—	—	—	27	3	30

(1) Excludes short-term cash investments: FE Consolidated - $326 million; FES - $196 million; OE - $4 million; JCP&L - $38 million.

(2) Excludes short-term cash investments: FE Consolidated - $164 million; FES - $74 million; OE - $2 million; JCP&L - $19 million.

Proceeds from the sale of investments in available-for-sale securities, realized gains and losses on those sales and interest and dividend income for the three years ended December 31, 2012 , 2011 and 2010 were as follows:

2012	Sale Proceeds	Realized Gains	Realized Losses	Interest and Dividend Income
	(In millions)			
FirstEnergy	$2,980	$179	$(99)	$70
FES	1,464	124	(73)	39
OE	105	—	—	3
JCP&L	516	12	(5)	14
2011	**Sale Proceeds**	**Realized Gains**	**Realized Losses**	**Interest and Dividend Income**
	(In millions)			
FirstEnergy	$4,207	$229	$(90)	$82
FES	1,843	80	(46)	47
OE	154	6	—	3
JCP&L	779	39	(11)	15
2010	**Sale Proceeds**	**Realized Gains**	**Realized Losses**	**Interest and Dividend Income**
	(In millions)			
FirstEnergy	$3,172	$126	$(107)	$79
FES	1,927	92	(75)	47
OE	83	2	—	3
JCP&L	411	10	(10)	14

Held-To-Maturity Securities

The following table provides the amortized cost basis, unrealized gains (there were no unrealized losses) and approximate fair values of investments in held-to-maturity securities as of December 31, 2012 and December 31, 2011:

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	December 31, 2012			December 31, 2011		
	Cost Basis	Unrealized Gains	Fair Value	Cost Basis	Unrealized Gains	Fair Value
	(In millions)					
Debt Securities						
FirstEnergy	$54	$30	$84	$402	$50	$452
OE	132	16	148	163	21	184

Investments in emission allowances, employee benefit trusts and cost and equity method investments totaling $644 million as of December 31, 2012, and $693 million as of December 31, 2011, are excluded from the amounts reported above.

During 2012, FE increased its ownership interest in a cost method investment. The increased investment triggered a change in the investment accounting from the cost method to the equity method. As a result of this change, FE recorded a reduction of $9 million to retained earnings in 2012 to reflect the investment as if it had been historically accounted for under the equity method.

LONG-TERM DEBT AND OTHER LONG-TERM OBLIGATIONS

All borrowings with initial maturities of less than one year are defined as short-term financial instruments under GAAP and are reported as "Short-term borrowings" on the Consolidated Balance Sheets at cost. Since these borrowings are short-term in nature, FirstEnergy believes that their costs approximate their fair market value. The following table provides the approximate fair value and related carrying amounts of long-term debt and other long-term obligations, excluding capital lease obligations and net unamortized premiums and discounts:

	December 31, 2012		December 31, 2011	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	(In millions)			
FirstEnergy	$16,957	$19,460	$17,165	$19,320
FES	4,194	4,524	3,675	3,931
OE	1,157	1,500	1,157	1,434
JCP&L	1,743	2,059	1,777	2,080

The fair values of long-term debt and other long-term obligations reflect the present value of the cash outflows relating to those securities based on the current call price, the yield to maturity or the yield to call, as deemed appropriate at the end of each respective period. The yields assumed were based on securities with similar characteristics offered by corporations with credit ratings similar to those of FirstEnergy and its subsidiaries. FirstEnergy classified short-term borrowings, long-term debt and other long-term obligations as Level 2 in the fair value hierarchy as of December 31, 2012 and December 31, 2011.

9. DERIVATIVE INSTRUMENTS

FirstEnergy is exposed to financial risks resulting from fluctuating interest rates and commodity prices, including prices for electricity, natural gas, coal and energy transmission. To manage the volatility relating to these exposures, FirstEnergy’s Risk Policy Committee, comprised of senior management, provides general management oversight for risk management activities throughout FirstEnergy. The Risk Policy Committee is responsible for promoting the effective design and implementation of sound risk management programs and oversees compliance with corporate risk management policies and established risk management practice. FirstEnergy also uses a variety of derivative instruments for risk management purposes including forward contracts, options, futures contracts and swaps. FirstEnergy accounts for derivative instruments on its Consolidated Balance Sheets at fair value unless they meet the normal purchases and normal sales criteria. Derivatives that meet those criteria are accounted for under the accrual method of accounting, and their effects are included in earnings at the time of contract performance. Changes in the fair value of derivative instruments that qualified and were designated as cash flow hedge instruments are recorded in AOCI. Changes in the fair value of derivative instruments that are not designated as cash flow hedge instruments are recorded in net income on a mark-to-market basis. FirstEnergy has contractual derivative agreements through 2018.

Cash Flow Hedges

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

Total net unamortized gains included in AOCI associated with instruments previously designated to be in a cash flow hedging relationship totaled $10 million and $19 million as of December 31, 2012 and December 31, 2011, respectively. Since the forecasted transactions remain probable of occurring, these amounts will be amortized into earnings over the life of the hedging instruments. Reclassifications from AOCI into other operating expense were $9 million of income and $26 million of loss during 2012 and 2011, respectively. Approximately $8 million of income is expected to be amortized to income during the next twelve months.

FirstEnergy has used forward starting swap agreements to hedge a portion of the consolidated interest rate risk associated with anticipated issuances of fixed-rate, long-term debt securities of its subsidiaries. These derivatives were treated as cash flow hedges, protecting against the risk of changes in future interest payments resulting from changes in benchmark U.S. Treasury rates between the date of hedge inception and the date of the debt issuance. No forward starting swap agreements accounted for as a cash flow hedge were outstanding as of December 31, 2012 or December 31, 2011. Total unamortized losses included in AOCI associated with prior interest rate cash flow hedges totaled $70 million and $79 million as of December 31, 2012 and December 31, 2011, respectively. Based on current estimates, approximately $9 million will be amortized to interest expense during the next twelve months. Reclassifications from AOCI into interest expense totaled $9 million and $12 million during 2012 and 2011, respectively.

Fair Value Hedges

FirstEnergy has used fixed-for-floating interest rate swap agreements to hedge a portion of the consolidated interest rate risk associated with the debt portfolio of its subsidiaries. These derivative instruments were treated as fair value hedges of fixed-rate, long-term debt issues, protecting against the risk of changes in the fair value of fixed-rate debt instruments due to lower interest rates. As of December 31, 2012 and December 31, 2011, no fixed-for-floating interest rate swap agreements were outstanding.

Unamortized gains included in long-term debt associated with prior fixed-for-floating interest rate swap agreements totaled $79 million and $102 million as of December 31, 2012 and December 31, 2011, respectively. Based on current estimates, approximately $22 million will be amortized to interest expense during the next twelve months. Reclassifications from long-term debt into interest expense totaled approximately $22 million during 2012 and 2011.

Commodity Derivatives

FirstEnergy uses both physically and financially settled derivatives to manage its exposure to volatility in commodity prices. Commodity derivatives are used for risk management purposes to hedge exposures when it makes economic sense to do so, including circumstances where the hedging relationship does not qualify for hedge accounting. Electricity forwards are used to balance expected sales with expected generation and purchased power. Natural gas futures are entered into based on expected consumption of natural gas primarily for use in FirstEnergy's combustion turbine units. Heating oil futures are entered into based on expected consumption of oil and the financial risk in FirstEnergy's coal transportation contracts. Derivative instruments are not used in quantities greater than forecasted needs.

As of December 31, 2012, FirstEnergy's net asset position under commodity derivative contracts was $98 million, which related to FES positions. Under these commodity derivative contracts, FES posted $29 million of collateral. Certain commodity derivative contracts include credit risk related contingent features that would require FES to post $10 million of additional collateral if the credit rating for its debt were to fall below investment grade.

Based on commodity derivative contracts held as of December 31, 2012, a decrease of 10% in commodity prices would decrease net income by approximately $3 million during the next twelve months.

Interest Rate Swaps

FirstEnergy has used forward starting swap agreements to hedge a portion of the consolidated interest rate risk associated with issuances of fixed-rate, long-term debt securities of its subsidiaries. These derivatives were considered economic hedges, protecting against the risk of increases in future interest payments resulting from increases in benchmark U.S. Treasury rates between the date of hedge inception and the date of the debt issuance. Changes in fair value of the forward starting swap agreements were recorded in net income on a market-to-market basis. FirstEnergy terminated $1.6 billion forward starting swap agreements on August 16, 2012 resulting in cash proceeds and a pre-tax gain, recorded as a reduction to interest expense, of approximately $6 million.

LCAPP

The LCAPP law was enacted in New Jersey during 2011 to promote the construction of qualified electric generation facilities. JCP&L maintains two LCAPP contracts, which are financially settled agreements that allow eligible generators to receive payments from, or make payments to, JCP&L pursuant to an annually calculated load-ratio share of the capacity produced by the generator based upon the annual forecasted peak demand as determined by PJM. During the second quarter of 2012, JCP&L began to account for these contracts as derivatives as a result of the generators clearing the 2015/2016 PJM RPM capacity auction. JCP&L expects to recover from its customers payments made to the generators and give credit to customers for payments from the generators under these contracts. As a result, the projected future obligations for the LCAPP contracts are reflected on the Consolidated Balance

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Sheets as derivative liabilities with a corresponding regulatory asset. Since the LCAPP contracts are subject to regulatory accounting, changes in their fair value do not impact earnings.

FTRs

FirstEnergy holds FTRs that generally represent an economic hedge of future congestion charges that will be incurred in connection with FirstEnergy's load obligations. FirstEnergy acquires the majority of its FTRs in an annual auction through a self-scheduling process involving the use of ARRs allocated to members of an RTO that have load serving obligations and through the direct allocation of FTRs from the PJM RTO. The PJM RTO has a rule that allows directly allocated FTRs to be granted to LSEs in zones that have newly entered PJM. For the first two planning years, PJM permits the LSEs to request a direct allocation of FTRs in these new zones at no cost as opposed to receiving ARRs. The directly allocated FTRs differ from traditional FTRs in that the ownership of all or part of the FTRs may shift to another LSE if customers choose to shop with the other LSE.

The future obligations for the FTRs acquired at auction are reflected on the Consolidated Balance Sheets and have not been designated as cash flow hedge instruments. FirstEnergy initially records these FTRs at the auction price less the obligation due to the RTO, and subsequently adjusts the carrying value of remaining FTRs to their estimated fair value at the end of each accounting period prior to settlement. Changes in the fair value of FTRs held by FES and AE Supply are included in other operating expenses as unrealized gains or losses. Unrealized gains or losses on FTRs held by FirstEnergy's utilities are recorded as regulatory assets or liabilities. Directly allocated FTRs are accounted for under the accrual method of accounting, and their effects are included in earnings at the time of contract performance.

The following tables summarize the fair value of derivative instruments on FirstEnergy's Consolidated Balance Sheets:
Derivatives not designated as hedging instruments:

Derivative Assets	Fair Value December 31, 2012	December 31, 2011	Derivative Liabilities	Fair Value December 31, 2012	December 31, 2011
	(In millions)			(In millions)	
Power Contracts			Power Contracts		
Current Assets	$153	$185	Current Liabilities	$(115)	$(196)
Noncurrent Assets	99	79	Noncurrent Liabilities	(36)	(51)
FTRs			FTRs		
Current Assets	7	1	Current Liabilities	(7)	(22)
Noncurrent Assets	1	—	Noncurrent Liabilities	(2)	(1)
NUGs - Noncurrent	36	56	NUGs - Noncurrent	(290)	(349)
LCAPP - Noncurrent	—	—	LCAPP - Noncurrent	(144)	—
Other Current Assets	—	—	Other Current Liabilities	(3)	—
	$296	$321		$(597)	$(619)

The following table summarizes the volumes associated with FirstEnergy's outstanding derivative transactions as of December 31, 2012:

	Purchases	Sales	Net	Units
	(In millions)			
Power Contracts	23	44	(21)	MWH
FTRs	46	—	46	MWH
NUGs	15	—	15	MWH
LCAPP	408	—	408	MW
Natural Gas	25	—	25	BTUs

The effect of derivative instruments on the Consolidated Statements of Income during 2012 and 2011, are summarized in the following tables:

	Years Ended December 31				
	Power Contracts (In millions)	FTRs	Interest Rate Swaps	Other	Total
Derivatives in a Hedging Relationship					
2012					
Loss Recognized in AOCI	$(9)	$—	$—	$—	$(9)
2011					
Gain Recognized in AOCI	$11	$—	$1	$—	$12
Effective Gain (Loss) Reclassified to:					
Purchased Power Expense	16	—	—	—	16
Revenues	(12)	—	—	—	(12)
Derivatives Not in a Hedging Relationship					
2012					
Unrealized Gain (Loss) Recognized in:					
Other Operating Expense	$92	$13	$—	$(3)	$102
Realized Gain (Loss) Reclassified to:					
Purchased Power Expense	$(277)	$—	$—	$—	$(277)
Revenues	302	22	—	—	324
Other Operating Expense	—	(61)	—	—	(61)
Fuel Expense	—	—	—	5	5
Interest Expense	—	—	6	—	6
2011					
Unrealized Gain (Loss) Recognized in:					
Purchased Power Expense	$120	$—	$—	$—	$120
Revenues	(3)	—	—	—	(3)
Other Operating Expense	(52)	(6)	2	—	(56)
Realized Gain (Loss) Reclassified to:					
Purchased Power Expense	$(159)	$—	$—	$—	$(159)
Revenues	16	42	(2)	—	56
Other Operating Expense	—	(100)	—	—	(100)

The unrealized and realized gains (losses) on FirstEnergy's derivative instruments subject to regulatory accounting during 2012 and 2011, are summarized in the following tables:

	Years Ended December 31				
	NUGs	LCAPP	Regulated FTRs	Other	Total
	(In millions)				
Derivatives Not in a Hedging Relationship with Regulatory Offset					
2012					
Unrealized Gain (Loss) on Derivative Instrument	$(201)	$(144)	$1	$—	$(344)
Realized Gain on Derivative Instrument	240	—	7	—	247
2011					
Unrealized Loss on Derivative Instrument	$(202)	$—	$(5)	$—	$(207)
Realized Gain (Loss) on Derivative Instrument	254	—	(3)	(10)	241

The following table provides a reconciliation of changes in the fair value of certain contracts that are deferred for future recovery from (or credit to) customers during 2012 and 2011:

	Years Ended December 31				
Derivatives Not in a Hedging Relationship with Regulatory Offset[(1)]	NUGs	LCAPP	Regulated FTRs	Other	Total
	(In millions)				
Outstanding net liability as of January 1, 2012	$(293)	$—	$(8)	$—	$(301)
Additions/Change in value of existing contracts	(201)	(144)	1	—	(344)
Settled contracts	240	—	7	—	247
Outstanding net liability as of December 31, 2012	$(254)	$(144)	$—	$—	$(398)
Outstanding net asset (liability) as of January 1, 2011	$(345)	$—	$—	$10	$(335)
Additions/Change in value of existing contracts	(202)	—	(5)	—	(207)
Settled contracts	254	—	(3)	(10)	241
Outstanding net liability as of December 31, 2011	$(293)	$—	$(8)	$—	$(301)

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

10. IMPAIRMENT OF LONG-LIVED ASSETS

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

FirstEnergy considers a variety of factors, including wholesale power prices, in its decision to operate, or not operate, a generating plant. If wholesale power prices represent a lower cost option, FirstEnergy may elect to fulfill its load obligation through purchasing electricity in the wholesale market as opposed to operating a generating plant. The effect of this decision on its results of operations would be to displace higher per unit fuel expense with lower per unit purchased power.

Generating Plant Deactivations

On January 26, 2012 and February 8, 2012, FG, MP and AE Supply announced the deactivation 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, Lakeshore, R. Paul Smith, Rivesville and Willow Island) with a total capacity of 3,349 MW due to MATS and other environmental regulations. As a result of this decision, FirstEnergy recorded a pre-tax impairment of $334 million to continuing operations during the year ended 2011. This impairment consisted of a $311 million write down of the carrying value of the plant assets, approximately $5 million in excessive SO2 emission allowances and an $18 million charge for excessive or obsolete inventory at these facilities. On April 25, 2012, PJM concluded its initial analysis of the reliability impacts from the previously announced plant deactivations and requested RMR arrangements for Eastlake Units 1-3, Ashtabula Unit 5 and Lake Shore Unit 18 through the spring of 2015. On July 10, 2012, and as amended on October 31, 2012, FirstEnergy filed with FERC, for informational purposes, the compensation arrangements for these units which will remain in effect for as long as these generating units continue to operate. As of September 1, 2012, Albright, Armstrong, Bay Shore (except for generating unit 1), Eastlake Units 4-5, R. Paul Smith, Rivesville and Willow Island have been deactivated. During the year ended December 31, 2012, FirstEnergy recognized pre-tax severance expense of approximately $14 million ($10 million by FES) as a result of the deactivations. These costs are included in "other operating expenses" in the Consolidated Statements of Income.

In addition to the emission allowance impairments in connection with the plant closures, FirstEnergy recorded during 2011, pre-tax impairment charges of approximately $6 million ($1 million for FES and $5 million for AE Supply) for NOx emission allowances that were expected to be obsolete after 2011 and approximately $16 million ($13 million for FES and $3 million for AE Supply) for excess SO_2 emission allowances in inventory that it expected will not be consumed in the future.

Fremont Energy Center

On March 11, 2011, FirstEnergy and American Municipal Power, Inc., entered into an agreement for the sale of Fremont Energy Center, which included two natural gas combined-cycle combustion turbines and a steam turbine capable of producing 544 MW of load-following capacity and 163 MW of peaking capacity. The execution of this agreement triggered a need to evaluate the recoverability of the carrying value of the assets associated with the Fremont Energy Center. The estimated fair value of the Fremont Energy Center was based on the purchase price outlined in the sale agreement with American Municipal Power, Inc. The result of this evaluation indicated that the carrying cost of the Fremont Energy Center was not fully recoverable. As a result of the recoverability evaluation, FirstEnergy recorded an impairment charge of $11 million to operating income in the first quarter of 2011. On July 28, 2011, FirstEnergy completed the sale of Fremont Energy Center to American Municipal Power, Inc.

Peaking Facilities

During 2011, FirstEnergy assessed the carrying values of certain peaking facilities that were to be sold or disposed of before the end of their useful lives. The estimated fair values were based on estimated sales prices quoted in an active market and indicated that the carrying costs of the peaking facilities were not fully recoverable. FirstEnergy recorded impairment charges of $23 million during 2011 and on October 18, 2011, FirstEnergy closed on the sale of the Richland and Stryker peaking facilities.

11. CAPITALIZATION

COMMON STOCK

Retained Earnings and Dividends

As of December 31, 2012, FirstEnergy’s unrestricted retained earnings were $2.9 billion. Dividends declared in 2012 were $2.20 per share, which included dividends of $0.55 per share paid in the second, third and fourth quarters of 2012 and dividends of $0.55 per share payable in the first quarter of 2013. Dividends declared in 2011 were $2.20 per share, which included dividends of $0.55 per share paid in the second, third and fourth quarter of 2011 and dividends of $0.55 per share paid in the first quarter of 2012. The amount and timing of all dividend declarations are subject to the discretion of the Board of Directors and its consideration of business conditions, results of operations, financial condition and other factors.

In addition to paying dividends from retained earnings, OE, CEI, TE, Penn, JCP&L, ME and PN have authorization from the FERC to pay cash dividends to FirstEnergy from paid-in capital accounts, as long as their FERC-defined equity to total capitalization ratio remains above 35%. In addition, TrAIL and AGC have authorization from the FERC to pay cash dividends to FE from paid-in capital accounts, as long as their FERC-defined equity to total capitalization ratio remains above 50% and 45%, respectively. The articles of incorporation, indentures, regulatory limitations and various other agreements relating to the long-term debt of certain FirstEnergy subsidiaries contain provisions that could further restrict the payment of dividends on their common stock. None of these provisions materially restricted FirstEnergy’s subsidiaries’ abilities to pay cash dividends to FirstEnergy as of December 31, 2012.

In 2011, FirstEnergy elected to change its method of recognizing actuarial gains and losses for its defined benefit pension plans and other postemployment benefit plans and applied this change retrospectively to all periods presented. The retrospective application of this change caused accumulated deficits for certain of the Utilities during those prior periods, including periods when dividends were paid from retained earnings. Previous to this accounting change, retained earnings were sufficient for those dividends that were declared and paid.

PREFERRED AND PREFERENCE STOCK

FirstEnergy and the Utilities were authorized to issue preferred stock and preference stock as of December 31, 2012, as follows:

	Preferred Stock Shares Authorized	Par Value	Preference Stock Shares Authorized	Par Value
FirstEnergy	5,000,000	$100		
OE	6,000,000	$100	8,000,000	no par
OE	8,000,000	$25		
Penn	1,200,000	$100		
CEI	4,000,000	no par	3,000,000	no par
TE	3,000,000	$100	5,000,000	$25
TE	12,000,000	$25		
JCP&L	15,600,000	no par		
ME	10,000,000	no par		
PN	11,435,000	no par		
MP	940,000	$100		
PE	10,000,000	$0.01		
WP	32,000,000	no par		

As of December 31, 2012, and 2011, there were no preferred or preference shares outstanding.

LONG-TERM DEBT AND OTHER LONG-TERM OBLIGATIONS

The following tables present outstanding long-term debt and capital lease obligations for FirstEnergy, FES, OE and JCP&L as of December 31, 2012 and 2011:

	As of December 31, 2012		As of December 31,	
(Dollar amounts in millions)	Maturity Date	Interest Rate	2012	2011
FirstEnergy:				
FMBs	2013 - 2038	3.340% - 9.740%	$2,587	$2,487
Secured notes - fixed rate	2013 - 2037	4.982% - 7.880%	2,113	2,725
Secured notes - variable rate	2013	0.140%	50	50
Total secured notes			2,163	2,775
Unsecured notes - fixed rate	2013 - 2039	2.150% - 7.700%	11,145	10,961
Unsecured notes - variable rate	2013	0.100% - 2.815%	959	782
Total unsecured notes			12,104	11,743
Capital lease obligations			176	108
Unamortized debt premiums			45	64
Unamortized merger fair value adjustments			103	160
Currently payable long-term debt			(1,999)	(1,621)
Total long-term debt and other long-term obligations			$15,179	$15,716
FES:				
Secured notes - fixed rate	2013 - 2018	5.150% - 12.000%	$689	$899
Secured notes - variable rate	2013	0.140%	50	50
Total secured notes			739	949
Unsecured notes - fixed rate	2013 - 2039	2.150% - 6.800%	2,769	2,218
Unsecured notes - variable rate	2013	0.130% - 0.160%	686	508
Total unsecured notes			3,455	2,726
Capital lease obligations			27	31
Unamortized debt discounts			(1)	(2)
Currently payable long-term debt			(1,102)	(905)
Total long-term debt and other long-term obligations			$3,118	$2,799
OE:				
FMBs	2018 - 2038	6.090% - 9.740%	$407	$407
Unsecured notes - fixed rate	2015 - 2036	5.450% - 6.875%	750	750
Capital lease obligations			29	11
Unamortized debt discounts			(10)	(11)
Currently payable long-term debt			(4)	(2)
Total long-term debt and other long-term obligations			$1,172	$1,155
JCP&L:				
Secured notes - fixed rate	2013 - 2021	5.410% - 6.160%	$243	$277
Unsecured notes - fixed rate	2016 - 2037	4.800% - 7.350%	1,500	1,500
Unamortized debt discounts			(6)	(7)
Currently payable long-term debt			(36)	(34)
Total long-term debt			$1,701	$1,736

See Note 5, Leases for additional information related to capital leases.

Securitized Bonds
Environmental Control Bonds
The consolidated financial statements of FirstEnergy include environmental control bonds issued by two bankruptcy remote, special purpose limited liability companies that are indirect subsidiaries of MP and PE. Proceeds from the bonds were used to construct environmental control facilities. The special purpose limited liability companies own the irrevocable right to collect non-bypassable environmental control charges from all customers who receive electric delivery service in MP's and PE's West Virginia service territories. Principal and interest owed on the environmental control bonds is secured by, and payable solely from, the proceeds of the environmental control charges. The right to collect environmental control charges is not included as an asset on FirstEnergy's consolidated balance sheets. Creditors of FirstEnergy, other than the special purpose limited liability companies, have no recourse to any assets or revenues of the special purpose limited liability companies. As of December 31, 2012 and 2011, $493 million and $513 million of environmental control bonds were outstanding, respectively.
Transition Bonds
The consolidated financial statements of FirstEnergy and JCP&L include the accounts of JCP&L Transition Funding and JCP&L Transition Funding II, wholly owned limited liability companies of JCP&L. In June 2002, JCP&L Transition Funding sold transition bonds to securitize the recovery of JCP&L's bondable stranded costs associated with the previously divested Oyster Creek Nuclear Generating Station. In August 2006, JCP&L Transition Funding II sold transition bonds to securitize the recovery of deferred costs associated with JCP&L's supply of BGS. JCP&L did not purchase and does not own any of the transition bonds, which are included as long-term debt on FirstEnergy's and JCP&L's Consolidated Balance Sheets. The transition bonds are the sole obligations of JCP&L Transition Funding and JCP&L Transition Funding II and are collateralized by each company's equity and assets, which consist primarily of bondable transition property. As of December 31, 2012 and 2011, $243 million and $287 million of the transition bonds were outstanding, respectively.
Bondable transition property represents the irrevocable right under New Jersey law of a utility company to charge, collect and receive from its customers, through a non-bypassable TBC, the principal amount and interest on transition bonds and other fees and expenses associated with their issuance. JCP&L sold its bondable transition property to JCP&L Transition Funding and JCP&L Transition Funding II and, as servicer, manages and administers the bondable transition property, including the billing, collection and remittance of the TBC, pursuant to separate servicing agreements with JCP&L Transition Funding and JCP&L Transition Funding II. For the two series of transition bonds, JCP&L is entitled to aggregate annual servicing fees of up to $628 thousand that are payable from TBC collections.
Other Long-term Debt
The Ohio Companies, Penn, FG and NG each have a first mortgage indenture under which they can issue FMBs secured by a direct first mortgage lien on substantially all of their property and franchises, other than specifically excepted property.
Based on the amount of FMBs authenticated by the respective mortgage bond trustees as of December 31, 2012, the sinking fund requirement for all FMBs issued under the various mortgage indentures amounted to payments of $7 million in 2012, all of which relate to Penn. Penn expects to meet its 2013 annual sinking fund requirement with a replacement credit under its mortgage indenture.
As of December 31, 2012, FirstEnergy's currently payable long-term debt included approximately $809 million (FES — $736 million) of variable interest rate PCRBs, the bondholders of which are entitled to the benefit of irrevocable direct pay bank LOCs. The interest rates on the PCRBs are reset daily or weekly. Bondholders can tender their PCRBs for mandatory purchase prior to maturity with the purchase price payable from remarketing proceeds, or if the PCRBs are not successfully remarketed, by drawings on the irrevocable direct pay LOCs. The subsidiary obligor is required to reimburse the applicable LOC bank for any such drawings or, if the LOC bank fails to honor its LOC for any reason, must itself pay the purchase price.
The following table presents scheduled debt repayments for outstanding long-term debt, excluding capital leases, fair value purchase accounting adjustments and unamortized debt discounts and premiums, for the next five years as of December 31, 2012. PCRBs that can be tendered for mandatory purchase prior to maturity are reflected in 2013.

Year	FirstEnergy	FES	OE	JCP&L

	(In millions)			
2013	$1,970	$1,097	$1	$36
2014	1,026	186	1	38
2015	1,639	815	151	41
2016	1,267	422	251	343
2017	1,736	162	1	279

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The following table classifies the outstanding variable rate put PCRBs and variable rate PCRBs by year, excluding unamortized debt discounts and premiums, for the next five years based on the next date on which the debt holders may exercise their right to tender their PCRBs. OE and JCP&L did not have any outstanding PCRBs as of December 31, 2012.

Year	FirstEnergy	FES
	(In millions)	
2013	$1,044	$970
2014	26	26
2015	313	313
2016	391	391
2017	130	130

Obligations to repay certain PCRBs are secured by several series of FMBs. Certain PCRBs are entitled to the benefit of irrevocable bank LOCs, to pay principal of, or interest on, the applicable PCRBs. To the extent that drawings are made under the LOCs, FG, NG and the applicable Utilities are entitled to a credit against their obligation to repay those bonds. FG, NG and the applicable Utilities pay annual fees based on the amounts of the LOCs to the issuing banks and are obligated to reimburse the banks or insurers, as the case may be, for any drawings thereunder. The insurers hold FMBs as security for such reimbursement obligations. In addition, OE has LOCs of $102 million and $31 million in connection with the sale and leaseback of Beaver Valley Unit 2 and Perry Unit 1, respectively.

The amounts and annual fees for PCRB-related LOCs for FirstEnergy and FES as of December 31, 2012, are as follows:

	Aggregate LOC Amount	Annual Fees
	(In millions)	
FirstEnergy	$818	1.65% to 3.30%
FES	744	1.65% to 3.30%

Debt Covenant Default Provisions

FirstEnergy has various debt covenants under certain financing arrangements, including its revolving credit facilities. The most restrictive of the debt covenants relate to the nonpayment of interest and/or principal on such debt and the maintenance of certain financial ratios. The failure by FirstEnergy to comply with the covenants contained in its financing arrangements could result in an event of default, which may have an adverse effect on its financial condition.

Additionally, there are cross-default provisions in a number of the financing arrangements. These provisions generally trigger a default in the applicable financing arrangement of an entity if it or any of its significant subsidiaries default under another financing arrangement in excess of a certain principal amount, typically $100 million. Although such defaults by any of the Utilities, ATSI or TrAIL would generally cross-default FirstEnergy financing arrangements containing these provisions, defaults by any of AE Supply, FES, FG or NG would generally not cross-default to applicable financing arrangements of FirstEnergy. Also, defaults by FirstEnergy would generally not cross-default applicable financing arrangements of any of FirstEnergy's subsidiaries. Cross-default provisions are not typically found in any of the senior notes or FMBs of FirstEnergy, FG, NG or the Utilities.

12. SHORT-TERM BORROWINGS AND BANK LINES OF CREDIT

FirstEnergy had $1,969 million of short-term borrowings as of December 31, 2012, and no significant short-term borrowings as of December 31, 2011. FirstEnergy's available liquidity as of January 31, 2013, was as follows: