LARGE FILING SEPARATOR SHEET

CASE NUMBER 14-1297-EL-SSO

FILE DATE 10/30/2015

SECTION: 1 of 2

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OCC 32

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PUCO EXHIBIT FILING

Date of Hearing: 10/26/2015

Case No. 14-1297-EL-SSO

PUCO Case Caption: In the Matter of the Application of Ohio Edison, The Cleveland Electric Illuminating Company, and The Toledo Edison Company for Authority to Provide for a Standard Service Offer Pursuant to R.C. 4928.143 in the Form of an Electric Security Plan.

List of exhibits being filed: Volume XXXII

OCC 32

Reporter's Signature: Karen Sue Gibson

Date Submitted: 10/30/2015

BEFORE THE PUBLIC UTILITIES COMMISSION OF OHIO

\- - -

In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company for Authority to Provide for a Standard Service Offer Pursuant to R.C. 4928.143 in the Form of an Electric Security Plan.	Case No. 14-1297-EL-SSO

\- - -

PROCEEDINGS

before Mr. Gregory Price, Ms. Mandy Chiles, and Ms. Megan Addison, Attorney Examiners, at the Public Utilities Commission of Ohio, 180 East Broad Street, Room 11-A, Columbus, Ohio, called at 9:00 a.m. on Monday, October 26, 2015.

\- - -

VOLUME XXXII

ARMSTRONG & OKEY, INC.
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Columbus, Ohio 43215-5201
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Section 1: 10-K (10-K)

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K
(Mark One)

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

For the FISCAL YEAR ended December 31, 2014

OR

☐ 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

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

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

Yes ☑ No ☐ FirstEnergy Corp.
Yes ☐ No ☑ FirstEnergy Solutions Corp.

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 ☐ No ☑ FirstEnergy Corp. and FirstEnergy Solutions Corp.

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 ☑ No ☐ FirstEnergy Corp. and FirstEnergy Solutions Corp.

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 ☑ No ☐ FirstEnergy Corp. and FirstEnergy Solutions Corp.

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.

☑ FirstEnergy Corp.
☐ FirstEnergy Solutions Corp.

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 ☑	FirstEnergy Corp.
Accelerated Filer ☐	N/A
Non-accelerated Filer (Do not check if a smaller reporting company) ☑	FirstEnergy Solutions Corp.
Smaller Reporting Company ☐	N/A

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

Yes ☐ No ☑ FirstEnergy Corp. and FirstEnergy Solutions Corp.

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., $14,551,349,320 as of June 30, 2014; and for FirstEnergy Solutions Corp., 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, 2015
FirstEnergy Corp., $0.10 par value	421,182,123
FirstEnergy Solutions Corp., no par value	7

FirstEnergy Corp. is the sole holder of FirstEnergy Solutions Corp. common stock.

Documents Incorporated By Reference

PART OF FORM 10-K INTO WHICH

DOCUMENT	DOCUMENT IS INCORPORATED
Proxy Statement for 2015 Annual Meeting of Shareholders to be held May 19, 2015	Parts II and III

This combined Form 10-K is separately filed by FirstEnergy Corp. and FirstEnergy Solutions Corp. 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 FirstEnergy Solutions Corp. is also attributed to FirstEnergy Corp.

OMISSION OF CERTAIN INFORMATION

FirstEnergy Solutions Corp. meets the conditions set forth in General Instruction I(1)(a) and (b) of Form 10-K and is therefore filing this Form 10-K with the reduced disclosure format specified in General Instruction I(2) to Form 10-K.

Forward-Looking Statements: Certain of the matters discussed in this Annual Report on Form 10-K are forward-looking statements, within the meaning of the Private Securities Litigation Reform Act of 1995, that are subject to risks and uncertainties. The factors that could cause actual results to differ materially from the forward-looking statements made by a Registrant include those factors discussed herein, including those factors with respect to such Registrants discussed in (a) ITEM 1A. Risk Factors, (b) ITEM 7. Management's Discussion and Analysis of Financial Condition and Results of Operations, and (c) other factors discussed herein and in other filings with the SEC by the Registrants. Readers are cautioned not to place undue reliance on these forward-looking statements, which apply only as of the date of this Form 10-K. None of the Registrants undertake any obligation to update these statements, except as required by law.

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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, which subsequently merged with and into FE on January 1, 2014
AESC	Allegheny Energy Service Corporation
AE Supply	Allegheny Energy Supply Company, LLC, an unregulated generation subsidiary
AGC	Allegheny Generating Company, a generation subsidiary of AE Supply and equity method investee of MP
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
Buchanan Energy	Buchanan Energy Company of Virginia, LLC
CEI	The Cleveland Electric Illuminating Company, an Ohio electric utility operating subsidiary
CES	*Competitive Energy Services, a reportable operating segment of FirstEnergy*
FE	FirstEnergy Corp., a public utility holding company
FELHC	FirstEnergy License Holding Company, Inc.
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, 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 wholly-owned 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
MP	Monongahela Power Company, a West Virginia electric utility operating subsidiary
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 FE 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 and West Virginia electric utility operating subsidiary
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

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

AEP	American Electric Power Company, Inc.
AFS	Available-for-sale
AFUDC	Allowance for Funds Used During Construction

ALJ	Administrative Law Judge
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
Apple®	Apple®, iPad® and iPhone® are registered trademarks of Apple Inc.
ARO	Asset Retirement Obligation
ARR	Auction Revenue Right
ASLB	Atomic Safety and Licensing Board
BGS	Basic Generation Service
BRA	PJM RPM Base Residual Auction
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
CBA	Collective Bargaining Agreement
CCR	Coal Combustion Residuals
CDWR	California Department of Water Resources
CERCLA	Comprehensive Environmental Response, Compensation, and Liability Act of 1980
CFR	Code of Federal Regulations
CFTC	Commodity Futures Trading Commission
CO_2	Carbon Dioxide
CONE	Cost-of-New-Entry
CSA	Coal Sales Agreement
CSAPR	Cross-State Air Pollution Rule
CTA	Consolidated Tax Adjustments
CWA	Clean Water Act
DCPD	Deferred Compensation Plan for Outside Directors
DCR	Delivery Capital Recovery
DOE	United States Department of Energy
DR	Demand Response
DSP	Default Service Plan
EDC	Electric Distribution Company
EDCP	Executive Deferred Compensation Plan
EE&C	Energy Efficiency and Conservation
EGS	Electric Generation Supplier
ELPC	Environmental Law & Policy Center
EMAAC	Eastern Mid-Atlantic Area Council of PJM
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
Facebook®	Facebook is a registered trademark of Facebook, Inc.
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

GLOSSARY OF TERMS, *Continued*

IBEW	International Brotherhood of Electrical Workers
ICE	IntercontinentalExchange, Inc.
ICG	International Coal Group Inc.
ICP	Amended and Restated 2007 Incentive Plan
IRS	Internal Revenue Service
ISO	Independent System Operator
kV	Kilovolt
KWH	Kilowatt-hour
LBR	Little Blue Run
LCAPP	Long-Term Capacity Agreement Pilot Program
LMP	*Locational Marginal Price*
LOC	Letter of Credit
LSE	Load Serving Entity
MAAC	Mid-Atlantic Area Council of PJM
MATS	Mercury and Air Toxics Standards
MDPSC	Maryland Public Service Commission
MISO	Midcontinent Independent System Operator, Inc.
MISO LTTR	MISO Long Term Financial Transmission Right
mmBTU	One Million British Thermal Units
Moody's	Moody's Investors Service, Inc.
MVP	Multi-Value Project
MW	Megawatt
MWD	Megawatt-day
MWH	Megawatt-hour
NDT	Nuclear Decommissioning Trust
NEIL	Nuclear Electric Insurance Limited
NERC	North American Electric Reliability Corporation
Ninth Circuit	United States Court of Appeals for the Ninth Circuit
NJBPU	New Jersey Board of Public Utilities
NMB	Non-Market Based
NOL	Net Operating Loss
NOV	Notice of Violation
NOx	Nitrogen Oxide
NPDES	National Pollutant Discharge Elimination System
NRC	Nuclear Regulatory Commission
NRG	NRG Energy, Inc.
NSR	New Source Review
NUG	Non-Utility Generation
NYISO	New York Independent System Operator
NYPSC	New York State Public Service Commission
OCC	Ohio Consumers' Counsel
OEPA	Ohio Environmental Protection Agency
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 L.L.C.

GLOSSARY OF TERMS, *Continued*

PJM Region	The aggregate of the zones within PJM
PJM Tariff	PJM Open Access Transmission Tariff
PM	Particulate Matter
POLR	Provider of Last Resort
PPUC	Pennsylvania Public Utility Commission
PSA	Power Supply Agreement
PSD	Prevention of Significant Deterioration
PTC	*Price-to-Compare*
PUCO	Public Utilities Commission of Ohio
PURPA	Public Utility Regulatory Policies Act of 1978
R&D	Research and Development
RCRA	Resource Conservation and Recovery Act
REC	Renewable Energy Credit
REIT	Real Estate Investment Trust
RFC	Reliability*First* Corporation
RFP	Request for Proposal
RGGI	Regional Greenhouse Gas Initiative
RMR	Reliability Must-Run
ROE	Return on Equity
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
SB221	Amended Substitute Senate Bill No. 221
SB310	Substitute Senate Bill No. 310
SBC	Societal Benefits Charge
SEC	United States Securities and Exchange Commission
SERTP	Southeastern Regional Transmission Planning
Seventh Circuit	United States Court of Appeals for the Seventh Circuit
SF_6	Sulfur Hexafluoride
SIP	State Implementation Plan(s) Under the Clean Air Act
SO_2	Sulfur Dioxide
SOS	Standard Offer Service
SPE	Special Purpose Entity
SREC	Solar Renewable Energy Credit
SSO	Standard Service Offer
TDS	Total Dissolved Solid
TMI-2	Three Mile Island Unit 2
TSC	Transmission Service Charge
Twitter®	Twitter is a registered trademark of Twitter, Inc.
U.S. Court of Appeals for the D.C. Circuit	United States Court of Appeals for the District of Columbia Circuit
UWUA	Utility Workers Union of America
VIE	Variable Interest Entity
VRR	Variable Resource Requirement
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. FE'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, FESC, FES and its principal subsidiaries (FG and NG), AE Supply, MP, PE, WP, FET and its principal subsidiaries (ATSI and TrAIL), and AESC. In addition, FE holds all of the outstanding common stock of other direct subsidiaries including: FirstEnergy Properties, Inc., FEV, FENOC, FELHC, Inc., GPU Nuclear, Inc., and AE Ventures, Inc.

Subsidiaries

FirstEnergy's revenues are primarily derived from electric service provided by its utility operating subsidiaries (OE, CEI, TE, Penn, JCP&L, ME, PN, MP, PE, and WP), ATSI 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 13.5 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 0.3 million. Penn complies with the regulations, orders, policies and practices prescribed by the SEC, FERC and PPUC.

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

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

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 a 50% ownership interest (210 MW) 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 portions of Maryland and West Virginia and provides transmission services in Virginia in an area totaling approximately 5,500 square miles. 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, 2014, MP owned or contractually controlled 3,580 MWs of generation capacity that is supplied to its electric utility business. In addition, MP is contractually obligated to provide power to PE 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.

ATSI was organized under the laws of the State of Ohio in 1998. ATSI owns major, high-voltage transmission facilities, which consist of approximately 7,500 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.

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, including a 500 kV 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 generating facilities and owns, through its NG subsidiary, 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, and purchases 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.

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 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 (1,200 MW) 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, FERC, and applicable state regulatory authorities. 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.

FirstEnergy's reportable operating segments are as follows: Regulated Distribution, Regulated Transmission and CES.

The Regulated Distribution segment distributes electricity through FirstEnergy's ten utility operating companies, serving approximately six 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, SSO and default service requirements in Ohio, Pennsylvania, New Jersey and Maryland.

The Regulated Transmission segment transmits electricity through transmission facilities owned and operated by ATSI, TrAIL, and certain of FirstEnergy's utilities (JCP&L, ME, PN, MP, PE and WP), and the regulatory asset associated with the abandoned PATH project.

The CES segment, through FES and AE Supply, primarily 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.

Corporate/Other con corporate support and other businesses that are below the quantifiable threshold for separate disclosure as a repor segment and interest expense on stand-alone holding company debt and corporate income taxes. Additionally, reconcili djustments for the elimination of inter-segment transactions are included in Corporate/Other. As of December 31, 2014 porate/Other had $4.2 billion of stand-alone holding company long-term debt, of which 28% was subject to variable-in rates, and $1.7 billion was borrowed by FE under its revolving credit facility.

Additional information garding FirstEnergy's reportable segments, which information is incorporated herein by reference, is provided in Note 18 ment Information, of the Combined Notes to Consolidated Financial Statements. FES does not have separate reportable ting segments.

Competitive an gulated Generation

As of February 17, 2 FirstEnergy's generating portfolio consists of 17,858 MW of diversified capacity (CES — 14,068 MW, including 885 MWs pacity scheduled to be deactivated by April 2015, and Regulated Distribution — 3,790 MW). Of the generation asset po , approximately 10,113 MW (56.5%) consist of coal-fired capacity; 4,048 MW (22.7%) consist of nuclear capacity; 1, W (7.9%) consist of hydroelectric capacity; 1,603 MW (9.0%) consist of oil and natural gas units; 496 MW (2.8%) consist d and solar power arrangements; and 188 MW (1.1%) consist of capacity entitlements to output from generation assets o by OVEC. All units are located within PJM and sell electric energy, capacity and other products into the wholesale marke at are operated by PJM. Within the CES segment's generation portfolio, 11,086 MW consist of FES' facilities that are ope by FENOC and FG (including entitlements from OVEC, wind and solar power arrangements), and except for portions o ain facilities that are subject to the sale and leaseback arrangements with non-affiliates for which the corresponding outpu ese arrangements is available to FES through power sales agreements, are all owned directly by NG and FG. Another 2, V of the CES' portfolio consists of AE Supply's facilities, including AE Supply's entitlement to 713 MW from AGC's Bath Co Virginia hydroelectric facility and 67 MW of AE Supply's 3.01% entitlement from OVEC's generation output. FES' genera cilities are concentrated primarily in Ohio and Pennsylvania and AE Supply's generating facilities are primarily located in P lvania, West Virginia, Virginia and Ohio.

Within the Regulated ibution segment's portfolio, 210 MW consist of JCP&L's 50% ownership interest in the Yards Creek hydroelectric facility w Jersey; and 3,580 MW consist of MP's facilities, including 487 MW from AGC's Bath County, Virginia hydroelectric ity that MP partially owns and 11 MW of MP's 0.49% entitlement from OVEC's generation output. MP's facilities are co rated primarily in West Virginia.

Utility Regulation

State Regulati

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

As competitive retail ic suppliers serving retail customers primarily in Ohio, Pennsylvania, Illinois, Michigan, New Jersey and Maryland, FES AE Supply are subject to state laws applicable to competitive electric suppliers in those states, including affiliate co conduct that apply to FES, AE Supply and their public utility affiliates. In addition, if any of the FirstEnergy affiliates to engage in the construction of significant new transmission or generation facilities, depending on the state, they may uired to obtain state regulatory authorization to site, construct and operate the new transmission or generation facility.

Federal Regu

With respect to their esale services and rates, the Utilities, AE Supply, ATSI, AGC, FES, FG, NG, PATH and TrAIL are subject to regulation RC. Under the FPA, FERC regulates rates for interstate wholesale sales, transmission of electric power, accounting and er matters, including construction and operation of hydroelectric projects. FERC regulations require ATSI, JCP&L, ME, MP , PN, WP and TrAIL to provide open access transmission service at FERC-approved rates, terms and conditions. Trans on facilities of ATSI, JCP&L, ME, MP, PE, PN, WP and TrAIL are subject to functional control by PJM and transmission vice using their transmission facilities is provided by PJM under the PJM 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 showing that the seller cannot exert market power in generation or transmission or erect barriers to entry into markets. The Utilities, AE Supply, FES, FG, NG, FirstEnergy Generation Mansfield Unit 1 Corp., Buchanan Generation, LLC, and Green Valley Hydro, LLC each have been authorized by FERC to sell wholesale power in interstate commerce and have a market-based rate tariff on file with FERC; although major wholesale purchases remain subject to regulation by the relevant state commissions. As a condition to selling electricity on a wholesale basis at market-based rates, the Utilities, AE Supply, FES, FG, NG, FirstEnergy Generation Mansfield Unit 1 Corp., Buchanan Generation, LLC, and Green Valley Hydro, LLC, like other entities granted market-based rate authority, must file electronic quarterly reports with FERC listing their sales transactions for the prior quarter. However, consistent with its historical practice, FERC has granted AE Supply, FES, FG, NG, FirstEnergy Generation Mansfield Unit 1 Corp., Buchanan Generation, LLC, and Green Valley Hydro, LLC a waiver from certain 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, NG, FirstEnergy Generation Mansfield Unit 1 Corp., Buchanan Generation, LLC, and Green Valley Hydro, LLC blanket authority to issue securities and assume liabilities under Section 204 of the FPA.

The nuclear generating facilities owned and leased by NG, OE and TE, 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.

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, NG, 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 occurrences are found, FirstEnergy develops information about the occurrence and develops a remedial response to the specific circumstances, including in appropriate cases "self-reporting" an occurrence to RFC. Moreover, it is clear that NERC, RFC and FERC will continue to refine existing reliability standards as well as to develop and adopt new reliability standards. Any inability on FirstEnergy's part to comply with the reliability standards for its bulk electric 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.

Regulatory Accounting

The Utilities, AGC, ATSI, PATH and TrAIL recognize, as regulatory assets and regulatory liabilities, costs which FERC and the various state utility commissions, as applicable, have authorized for recovery/return from/to customers in future periods or for which authorization is probable. Without the probability of such authorization, costs currently recorded as regulatory assets and regulatory liabilities would have been charged to income as incurred. All regulatory assets and liabilities are expected to be recovered/returned from/to customers. Based on current ratemaking procedures, the Utilities, AGC, 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, AGC, 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, AGC, 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 or liabilities are removed from the balance sheet in accordance with GAAP.

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 adopted a statute in 2008 codifying the EmPOWER Maryland goals to reduce electric consumption by 10% and reduce electricity demand by 15%, in each case by 2015. PE's initial plan submitted in compliance with the statute was approved in 2009, at which time expenditures were estimated to be approximately $101 million for the PE programs for the entire period of 2009-2015. PE's third plan, covering the three-year period 2015-2017, was approved by the MDPSC on December 23, 2014. The projected costs of the 2015-2017 plan are approximately $64 million for that three year period. PE continues to recover program costs subject to a five-year amortization. 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.

The MDPSC adopted rules, effective May 28, 2012, that set utility-specific SAIDI and SAIFI targets for 2012-2015; prescribed detailed tree-trimming requirements, outage restoration and downed wire response deadlines; imposed other reliability and customer satisfaction requirements; and established annual reporting requirements. The MDPSC is required to assess each utility's compliance with the new rules, and may assess penalties of up to $25,000 per day, per violation. The MDPSC issued orders accepting PE's reports on compliance under the new rules on September 3, 2013 and August 27, 2014.

On February 27, 2013, the MDPSC issued an order (the February 27 Order) requiring the Maryland electric utilities to submit analyses, relating to the costs and benefits of making further system and staffing enhancements in order to attempt to reduce storm outage durations. The order further required the Staff of the MDPSC to report on possible performance-based rate structures and to propose additional rules relating to feeder performance standards, outage communication and reporting, and sharing of special needs customer information. PE's final filing on September 3, 2013, discussed the steps needed to harden the utility's system in order to attempt to achieve various levels of storm response speed described in the February 27 Order, and projected that it would require approximately $2.7 billion in infrastructure investments over 15 years to attempt to achieve the quickest level of response for the largest storm projected in the February 27 Order. On July 1, 2014, the Staff of the MDPSC issued a set of reports that recommended the imposition of extensive additional requirements in the areas of storm response, feeder performance, estimates of restoration times, and regulatory reporting. The Staff also recommended the imposition of penalties, including customer rebates, for a utility's failure or inability to comply with the escalating standards of storm restoration speed proposed by the Staff. In addition, the Staff proposed that the utilities be required to develop and implement system hardening plans, up to a rate impact cap on cost. The MDPSC conducted a hearing September 15-18, 2014, to consider certain of these matters, and has not yet scheduled further proceedings on any of the matters.

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.

In an order issued July 31, 2012, the NJBPU 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 by JCP&L requesting approval to increase revenues by approximately $31 million, which included the recovery of 2011 storm restoration costs but excluded approximately $603 million of costs incurred in 2012 associated with the impact of Hurricane Sandy. In the initial briefs of the parties, the Division of Rate Counsel recommended that base rate revenues be reduced by $214.9 million while the NJBPU Staff recommended a $207.4 million reduction (such amounts do not address the revenue requirements associated with the major storm events of 2011 and 2012). On May 5, 2014, JCP&L submitted updated schedules to reflect the result of the generic storm cost proceeding, discussed below, to revise the debt rate to 5.93%, and to request that base rate revenues be increased by $9.1 million, including the recovery of 2011 storm costs. The record in the case was closed as of June 30, 2014. The ALJ provided his initial Decision on January 8, 2015, which recommended an annual revenue reduction of $107.5 million and did not include the recovery of 2012 storm costs or any CTA. On February 11, 2015, the NJBPU approved a 45-day extension to render a final decision.

On January 23, 2013, the NJBPU opened a generic proceeding to review its policies with respect to the use of a CTA in base rate cases. The NJBPU and its Staff solicited, and were provided, input from interested stakeholders, including utilities and the Division of Rate Counsel. On June 18, 2014, the NJBPU Staff proposed to amend current CTA policy by: 1) calculating savings using a 5 year look back from the beginning of the test year; 2) allocating savings with 75% retained by the company and 25% allocated to rate payers; and 3) excluding transmission assets of electric distribution companies in the savings calculation. JCP&L and other stakeholders filed written comments on the Staff proposal. In its Order issued October 22, 2014, the NJBPU stated it would continue to apply its current CTA policy in base rate cases, subject to incorporating the staff proposed modifications (as discussed above). For pending base rate cases in which the record had closed, such as JCP&L's, the NJBPU would, following an initial decision of the ALJ, reopen the record for the limited purpose of adding a CTA calculation reflecting the modified policy and allow parties the opportunity to comment. FirstEnergy expects the application of the modified policy in the pending JCP&L base rate case to reduce annual revenues by approximately $5 million. On November 5, 2014, the Division of Rate Counsel appealed the NJBPU Order to the New Jersey Superior Court. JCP&L has filed to participate as a respondent in that proceeding.

On March 20, 2013, the NJBPU ordered that a generic proceeding be established to investigate the prudence of costs incurred by all New Jersey utilities for service restoration efforts associated with the major storm events of 2011 and 2012. The Order provided that if any utility had already filed a proceeding for recovery of such storm costs, to the extent the amount of approved recovery had not yet been determined, the prudence of such costs would be reviewed in the generic proceeding. On May 31, 2013, the NJBPU clarified its earlier order to indicate that the 2011 major storm costs would be reviewed expeditiously in the generic proceeding, with the goal of maintaining the base rate case schedule established by the ALJ where recovery of such costs would be addressed. The NJBPU further indicated that it would review the 2012 major storm costs in the generic proceeding and the recovery of such costs would be considered through a Phase II in the existing base rate case or through another appropriate method to be determined at the conclusion of the generic proceeding. On June 21, 2013, JCP&L filed a detailed report in support of recovery of major storm costs with the NJBPU. On February 24, 2014, a Stipulation was filed with the NJBPU by JCP&L, the Division of Rate Counsel and NJBPU Staff which will allow recovery of $736 million of JCP&L's $744 million of costs related to the significant weather events of 2011 and 2012. As a result, FirstEnergy recorded a regulatory asset impairment charge of approximately $8 million (pre-tax) as of December 31, 2013. By its Order of March 19, 2014, the NJBPU approved the Stipulation of Settlement. Although the settlement permits recovery of 2011 and 2012 storm costs, the recovery of the 2011 costs will be addressed in the pending base rate case; whereas the manner and timing of recovery of the 2012 storm costs totaling $580 million will be determined by the NJBPU.

Ohio Regulatory Matters

The Ohio Companies primarily operate under their ESP 3 plan which expires on May 31, 2016. The material terms of ESP 3 include:

- Continuing the current base distribution rate freeze through May 31, 2016;
- Continues collection of lost distribution revenues associated with energy efficiency and peak demand reduction programs;
- Continuing to provide economic development and assistance to low-income customers for the two-year plan period at levels established in the prior ESP;
- A 6% generation rate 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);
- Continuing to provide power to non-shopping customers at a market-based price set through an auction process;
- Continuing Rider DCR that allows continued investment in the distribution system for the benefit of customers;
- Continuing commitment not to recover from retail customers certain costs related to transmission cost allocations 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, subject to the outcome of certain FERC proceedings;
- 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, Ohio's renewable energy and energy efficiency standard, 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.

Notices of appeal of the Ohio Companies' ESP 3 plan to the Supreme Court of Ohio were filed by the Northeast Ohio Public Energy Council and the ELPC. The matter has not yet been scheduled for oral argument.

The Ohio Companies filed an application with the PUCO on August 4, 2014 seeking approval of their ESP IV entitled *Powering Ohio's Progress*. The Ohio Companies have requested a decision by the PUCO by April 8, 2015. The Ohio Companies filed a partial Stipulation and Recommendation on December 22, 2014. The evidentiary hearing on the ESP IV is scheduled to commence on April 13, 2015. The material terms of the proposed plan include:

- Continuing a base distribution rate freeze through May 31, 2019;
- Continuing collection of lost distribution revenues associated with energy efficiency and peak demand reduction programs;
- Providing economic development and assistance to low-income customers for the three-year plan period;
- An Economic Stability Program providing for a retail rate stability rider to flow through charges or credits representing the net result of the costs paid to FES through a proposed 15-year purchase power agreement for the output of Sammis, Davis-Besse and FES' share of OVEC against the revenues received from selling the output into the PJM markets over the same period;
- Continuing to provide power to non-shopping customers at a market-based price set through an auction process;
- Continuing Rider DCR with increased revenue caps of approximately $30 million per year that allows continued investment supporting the distribution system for the benefit of customers;
- A commitment not to recover from retail customers certain costs related to transmission cost allocations for the longer of the five-year period from June 1, 2011 through May 31, 2016 or when the amount of such costs avoided by customers for certain types of products totals $360 million, including appropriately such costs from MISO along with such costs from PJM, subject to the outcome of certain FERC proceedings; and
- General updates to electric service regulations and tariffs to reflect regulatory orders, administrative rule changes, and current practices.

Under Ohio's energy efficiency standards (SB221 and SB310), and the Ohio Companies' filing of amended energy efficiency plans, the Ohio Companies are required to implement energy efficiency programs that achieve a total annual energy savings equivalent of approximately 2,237 GWHs in 2014, 2015 and 2016. The Ohio Companies are also required to reduce peak demand in 2009 by 1%, with an additional 0.75% reduction each year thereafter through 2014, and retain the 2014 level for 2015 and 2016, and then increase the benchmark by an additional 0.75% thereafter through 2020.

On March 20, 2013, the PUCO approved the three-year energy efficiency portfolio plans for 2013-2015, estimated to cost the Ohio Companies approximately $250 million over the three-year period, which is expected to be recovered in rates. Applications for rehearing were filed by the Ohio Companies and several other parties. On July 17, 2013, the PUCO denied the Ohio Companies' application for rehearing, in part, but authorized the Ohio Companies to receive 20% of any revenues obtained from offering energy efficiency and DR reserves into the PJM auction. The PUCO also confirmed that the Ohio Companies can recover PJM costs and applicable penalties associated with PJM auctions, including the costs of purchasing replacement capacity from PJM incremental auctions, to the extent that such costs or penalties are prudently incurred. On August 16, 2013, ELPC and OCC filed applications for rehearing, which were granted for the sole purpose of further consideration of the issue. On September 24, 2014, the Ohio Companies filed an amendment to their portfolio plan as contemplated by SB310, seeking to suspend certain programs for the 2015-2016 period in order to better align the plan with the new benchmarks under SB310. On November 20, 2014, the PUCO approved the Ohio Companies' amended portfolio plan. Several applications for rehearing were filed, and the PUCO granted those applications for further consideration of the matters specified in those applications.

On September 16, 2013, the Ohio Companies filed with the Supreme Court of Ohio a notice of appeal of the PUCO's July 17, 2013 Entry on Rehearing related to energy efficiency, alternative energy, and long-term forecast rules stating that the rules issued by the PUCO are inconsistent with, and are not supported by, statutory authority. On October 23, 2013, the PUCO filed a motion to dismiss the appeal, which is still pending. The matter has not been scheduled for oral argument.

Ohio law requires electric utilities and electric service companies in Ohio to serve part of their load from renewable energy resources measured by an annually increasing percentage amount through 2024, except 2015 and 2016 that remain at the 2014 level. The Ohio Companies conducted RFPs in 2009, 2010 and 2011 to secure RECs to help meet these renewable energy requirements. In September 2011, the PUCO opened a docket to review the Ohio Companies' alternative energy recovery rider through which the Ohio Companies recover the costs of acquiring these RECs. The PUCO issued an Opinion and Order on August 7, 2013 approving the Ohio Companies' acquisition process and their purchases of RECs to meet statutory mandates in all instances except for part of the purchases arising from one auction and directing the Ohio Companies to credit non-shopping customers in the amount of $43.4 million, plus interest, on the basis that the Ohio Companies did not prove such purchases were prudent. Based on the PUCO ruling, a regulatory charge of approximately $51 million, including interest, was recorded in the fourth quarter of 2013. On December 24, 2013, following the denial of their application for rehearing, the Ohio Companies filed a notice of appeal and a motion for stay of the PUCO's order with the Supreme Court of Ohio, which was granted. On February 18, 2014, the OCC and the ELPC also filed appeals of the PUCO's order. The Ohio Companies filed their merit brief with the Supreme Court of Ohio on March 6, 2014 and the briefing process concluded on December 24, 2014. The matter is not yet scheduled for oral argument.

On April 9, 2014, the PUCO initiated a generic investigation of marketing practices in the competitive retail electric service market, with a focus on the marketing of fixed-price or guaranteed percent-off SSO rate contracts where there is a provision that permits the pass-through of new or additional charges.

Pennsylvania Regulatory Matters

The Pennsylvania Companies currently operate under DSPs that expire on May 31, 2015, 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 July 24, 2014, the PPUC unanimously approved a settlement of the Pennsylvania Companies' DSPs for the period of June 1, 2015 through May 31, 2017, that provides for quarterly descending clock auctions to procure 3, 12 and 24-month energy contracts, as well as one RFP seeking 2-year contracts to secure SRECs for ME, PN and Penn.

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 refunded those amounts to customers over 29-months concluding in the second quarter of 2013. On appeal, the Commonwealth Court affirmed 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. The Pennsylvania Supreme Court denied ME's and PN's Petition for Allowance of Appeal and the Supreme Court of the United States denied ME's and PN's Petition for Writ of Certiorari. The U.S. District Court for the Eastern District of Pennsylvania granted the PPUC's motion to dismiss the complaint filed by ME and PN to obtain 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. As a result of the U.S. District Court's decision, FirstEnergy recorded a regulatory asset impairment charge of approximately $254 million (pre-tax) in the quarter ended September 30, 2013. On appeal, on September 16, 2014, in a split decision, two judges of a three-judge panel of the United States Court of Appeals for the Third Circuit affirmed the U.S. District Court's dismissal of the complaint, agreeing that ME and PN had litigated the issue in the state proceedings and thus were precluded from subsequent litigation in federal court. On September 30, 2014, ME and PN filed for rehearing and rehearing en banc before the Third Circuit and, on October 15, 2014, the Third Circuit rejected that rehearing request. ME and PN filed a Petition for Certiorari with the U.S. Supreme Court on February 12, 2015.

Pursuant to Pennsylvania's EE&C legislation (Act 129 of 2008), 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 directed all of the electric utilities in Pennsylvania to submit by November 15, 2012, a Phase II EE&C Plan that would be in effect for the period June 1, 2013 through May 31, 2016. The PPUC deferred ruling on the need to create peak demand reduction targets and did not include a peak demand reduction requirement in the Phase II plans. On March 14, 2013, the PPUC adopted a settlement among the Pennsylvania Companies and interested parties and approved the Pennsylvania Companies' Phase II EE&C Plans for the period 2013-2016. Total costs of these plans are expected to be approximately $234 million and recoverable through the Pennsylvania Companies' reconcilable EE&C riders.

On August 4, 2014, the Pennsylvania Companies each filed tariffs with the PPUC proposing general rate increases associated with their distribution operations. The filings request approval to increase operating revenues by approximately $151.9 million at ME, $119.8 million at PN, $28.5 million at Penn, and $115.5 million at WP based upon fully projected future test years for the twelve months ending April 30, 2016 at each of the Pennsylvania Companies. On February 3, 2015, each of the Pennsylvania Companies filed a Joint Petition for Settlement seeking PPUC approval of the agreements reached in each proceeding which included, among other things: 1) increases in current distribution revenues of $89.3 million for ME, $90.8 million for PN, $15.9 million for Penn and $96.8 million for WP; 2) a Universal Services Charge Rider to be established for WP; 3) storm reserve accounts for future storm recovery to be established for each of the Pennsylvania Companies; and 4) certain other operational and customer service-related provisions. The sole issue reserved for briefing was with respect to the scope and pricing of the Companies' proposed LED offerings. Orders on the proposed increases are expected in May 2015.

West Virginia Regulatory Matters

On April 30, 2014, MP and PE filed a rate case, as amended on June 13, 2014, requesting a base rate increase of approximately $104 million, or 9.9%, based on an historic 2013 test year. The filing also included a request for an additional $48 million to recover by surcharge costs for new and existing vegetation management programs. On November 3, 2014, a Joint Stipulation was submitted by all parties which settled all issues in the proceeding. The settlement includes, among other things: a $15 million increase in base rate revenues effective February 25, 2015; the implementation of a Vegetation Management Surcharge effective February 25, 2015 to recover all costs related to both new and existing vegetation maintenance programs; authority to establish a regulatory asset for MATS investments placed into service in 2016 and 2017; authority to defer, amortize and recover over a 5-year period approximately $46 million of storm restoration costs; and elimination of the Temporary Transaction Surcharge for costs associated with MP's acquisition of the Harrison plant in October 2013 and movement of those costs into base rates effective February 25, 2015. On February 3, 2015, the WVPSC approved the settlement in full and without modification. MP and PE's new rates will go into effect February 25, 2015.

On August 29, 2014, MP and PE filed their annual ENEC case proposing an approximate $65.8 million annual increase in ENEC rates, which is a 5.7% overall increase to existing rates. The increase is comprised of an actual $51.6 million under-recovered balance as of June 30, 2014, and a projected $14.2 million in under-recovery for the 2015 rate effective period. A settlement was reached by all the parties, which was filed with the WVPSC on December 2, 2014. The parties agreed to defer $16.8 million of the energy portion of the under-recovery balance for medium and large customers for one year at a carrying cost of 4% in order to mitigate the proposed rate impact to those customers. The settlement permits MP and PE to recover all of their costs incurred during the two year review period and closes the review period except for two coal issues for further review in next year's ENEC case. On January 29, 2015, the WVPSC approved the settlement in full without modification and new ENEC rates will go into effect February 25, 2015.

FERC Matters

PJM Transmission Rates

PJM and its stakeholders have been debating the proper method to allocate costs for new transmission facilities. While FirstEnergy and other parties advocate for a traditional "beneficiary pays" (or usage based) approach, others advocate for "socializing" the costs on a load-ratio share basis, where each customer in the zone would pay based on its total usage of energy within PJM. This question has been the subject of extensive litigation before FERC and the appellate courts, including most recently before the Seventh Circuit. On June 25, 2014, a divided three-judge panel of the Seventh Circuit ruled that FERC had not quantified the benefits that western PJM utilities would derive from certain new 500 kV or higher lines and thus had not adequately supported its decision to socialize the costs of these lines. The majority found that eastern PJM utilities are the primary beneficiaries of the lines, while western PJM utilities are only incidental beneficiaries, and that, while incidental beneficiaries should pay some share of the costs of the lines, that share should be proportionate to the benefit they derive from the lines, and not on load-ratio share in PJM as a whole. The court remanded the case to FERC, which issued an order setting the issue of cost allocation for hearing and settlement proceedings. Settlement discussions under a FERC-appointed settlement judge are ongoing.

Order No. 1000, issued by FERC on July 21, 2011, announced new policies regarding transmission planning and transmission cost allocation, requiring the submission of a compliance filing by PJM and 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. On August 15, 2014 the U.S. Court of Appeals for the D.C. Circuit affirmed Order No. 1000, including its termination of certain "right of first refusal" privileges discussed in more detail below. The court subsequently denied a request for rehearing of its decision.

In series of orders, including certain of the orders related to the Order No. 1000 proceedings, FERC has asserted that the PJM transmission owners do not hold an incumbent "right of first refusal" to construct, own and operate transmission projects within their respective footprints that are approved as part of PJM's RTEP process. FirstEnergy and other PJM transmission owners have appealed these rulings, and those appeals are pending before the U.S. Court of Appeals for the D.C. Circuit.

To demonstrate compliance with the regional cost allocation principles of Order No. 1000, the PJM transmission owners, including FirstEnergy, proposed a hybrid allocation of 50% beneficiary pays and 50% socialized to be effective for RTEP projects approved by the PJM Board of Managers on, and after, the requested February 1, 2013 effective date of the compliance filing. FERC has accepted that approach.

Separately, the PJM transmission owners, including FirstEnergy, submitted filings to FERC setting forth the cost allocation method for projects that cross the borders between the PJM Region and: (1) the NYISO region; (2) the MISO region; and (3) the FERC-jurisdictional members of the SERTP region. These filings propose to allocate the cost of these interregional transmission projects based on the costs of projects that otherwise would have been constructed separately in each region, or, in the case of MISO, indicate that the cost allocation provisions for interregional transmission projects provided in the Joint Operating Agreement between PJM and MISO comply with the requirements of Order No. 1000. FERC accepted the PJM/MISO and PJM/SERTP filing, subject to refund and further compliance requirements. The PJM/NYISO cross-border project cost allocation filing remains pending before FERC.

The outcome of these proceedings and their impact, if any, on FirstEnergy cannot be predicted at this time.

RTO Realignment

On June 1, 2011, ATSI and the ATSI zone transferred from MISO to PJM. While many of the matters involved with the move have been resolved, FERC denied recovery under ATSI's transmission rate for certain charges that collectively can be described as "exit fees" and certain other transmission cost allocation charges totaling approximately $78.8 million until such time as ATSI submits a cost/benefit analysis demonstrating net benefits to customers from the move. FERC rejected a proposed settlement agreement to resolve the exit fee and transmission cost allocation issues, stating that its action is without prejudice to ATSI submitting a cost/benefit analysis demonstrating that the benefits of the RTO realignment decisions outweigh the exit fee and transmission cost allocation charges. FirstEnergy's request for rehearing of FERC's order remains pending.

Separately, the question of ATSI's responsibility for certain costs for the "Michigan Thumb" transmission project continues to be disputed. Potential responsibility arises under the MISO MVP tariff, which has been litigated in complex proceedings before FERC and certain U.S. appellate courts. In the event of a final non-appealable order that rules that ATSI must pay these charges, ATSI will seek recovery of these charges through its formula rate. On a related issue, FirstEnergy joined certain other PJM transmission owners in a protest of MISO's proposal to allocate MVP costs to energy transactions that cross MISO's borders into the PJM Region. On January 22, 2015, FERC issued an order establishing a paper hearing on remand from the Seventh Circuit of the issue of whether any limitation on "export pricing" for sales of energy from MISO into PJM is justified in light of applicable FERC precedent. Initial comments on the MISO/PJM MVP issue are due March 9, 2015, and reply comments are due April 8, 2015.

In addition, in a May 31, 2011 order, FERC ruled that the costs for certain "legacy RTEP" transmission projects in PJM approved before ATSI joined PJM could be charged to transmission customers in the ATSI zone. The amount to be paid, and the question of derived benefits, is pending before FERC as a result of the Seventh Circuit's June 25, 2014 order described above under PJM Transmission Rates.

The outcome of those proceedings that address the remaining open issues related to ATSI's move into PJM cannot be predicted at this time.

2014 ATSI Formula Rate Filing

On October 31, 2014, ATSI filed a proposal with FERC to change the structure of its formula rate. The proposed change requested to move from an "historical looking" approach, where transmission rates reflect actual costs for the prior year, to a "forward looking" approach, where transmission rates would be based on the estimated costs for the coming year, with an annual true up. Several parties protested ATSI's filing. On December 31, 2014, FERC issued an order accepting ATSI's filing effective January 1, 2015, as requested, subject to refund and the outcome of hearing and settlement proceedings. Settlement discussions under a FERC-appointed settlement judge are ongoing. FERC also initiated an inquiry pursuant to Section 206 of the FPA into ATSI's ROE and certain other matters, with a refund effective date of January 12, 2015, for any refund resulting from the inquiry. A procedural schedule for the Section 206 inquiry has not yet been established.

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 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. The California Parties appealed FERC's decision back to the Ninth Circuit, where the appeal remains pending. AE Supply joined with other intervenors in the case and filed a brief in support of FERC's dismissal of the case. Oral argument was held on February 11, 2015. The matter is now before the Ninth Circuit for decision.

In another proceeding, in June 2009, the California Attorney General, on behalf of certain California parties, filed a 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 FERC granted. The California Attorney General 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

On August 24, 2012, the PJM Board of Managers canceled the PATH project, a proposed transmission line from West Virginia through Virginia and into Maryland which PJM had previously suspended in February 2011. As a result of PJM canceling the project, approximately $62 million and approximately $59 million in costs incurred by PATH-Allegheny and PATH-WV (an equity method investment for FE), respectively, were reclassified from net property, plant and equipment to a regulatory asset for future recovery. PATH-Allegheny and PATH-WV requested authorization from FERC to recover the costs with a proposed ROE of 10.9% (10.4% base plus 0.5% for RTO membership) from PJM customers over five years. FERC issued an order denying the 0.5% ROE 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 proceedings and hearing if the parties do not agree to a settlement. On March 24, 2014, the FERC Chief ALJ terminated settlement judge procedures and appointed an ALJ to preside over the hearing phase of the case. The FERC Chief ALJ later extended the procedural schedule to allow time for the parties to address the applicability of FERC's Opinion No. 531 to the PATH proceedings. FERC's Opinion No. 531, as discussed below, revises FERC's methodology for calculating ROE. The hearing is scheduled to commence in March 2015.

MISO Capacity Portability

On June 11, 2012, in response to certain arguments advanced by MISO, 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. FirstEnergy and other parties have submitted filings arguing that MISO's concerns largely are without foundation and suggested that FERC address the remaining concerns in the existing stakeholder process that is described in the PJM/MISO Joint Operating Agreement. FERC has not mandated a solution, and the RTOs and affected parties are working to address the MISO's proposal in stakeholder proceedings. In January 2015, the RTOs and affected parties indicated to FERC that discussions on the various issues are continuing. 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.

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. FE also performs bilateral transactions for the purpose of hedging the price differences between the location of supply resources and retail load obligations. 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 2010, FES and AE Supply have lost more than $94 million in revenues that they otherwise would have received as FTR holders to hedge congestion costs. FES and AE Supply expect to continue to experience significant underfunding.

On February 15, 2013, FES and AE Supply filed a renewed complaint with FERC for the purpose of changing the PJM Tariff to eliminate FTR underfunding. On June 5, 2013, FERC issued its order denying the new complaint. Requests for rehearing, and all subsequent filings in the docket, are pending before FERC. The PJM stakeholders continue to discuss FTR underfunding.

A recent and related issue is the effect that certain financial trades have on congestion. On August 29, 2014, FERC instituted an investigation to address the question of whether the current rules regarding "Up-to Congestion" transactions are just and reasonable. FESC, on behalf of FES and the Utilities, filed comments supporting the investigation, arguing that PJM Tariff changes would decrease the incidence of Up-to Congestion transactions, and funding for FTRs likely would increase. FERC convened a technical conference on January 7, 2015 to discuss application of certain FTR-related rules to Up-to Congestion and virtual transactions and whether PJM's current uplift allocation for Up-to Congestion and virtual transactions is just and reasonable. FERC action following the technical conference is pending.

PJM Market Reform: 2014 PJM RPM Tariff Amendments

In late 2013 and early 2014, PJM submitted a series of amendments to the PJM Tariff to ensure that resources that clear in the RPM auctions are available as physical resources in the delivery year and that the rules implement comparable obligations for different types of resources. PJM's filings can be grouped into four categories: (i) DR; (ii) imports; (iii) modeling of transmission upgrades in calculating geographic clearing prices; and (iv) arbitrage/capacity replacement. In each of the relevant dockets, FirstEnergy and other parties submitted comments largely supporting PJM's proposed amendments. FERC largely approved the PJM Tariff amendments as proposed by PJM regarding DR, imports, and transmission upgrade modeling. Compliance filings pursuant to and requests for rehearing of certain of these orders are pending before FERC. However, FERC rejected the arbitrage/capacity replacement amendments, directing instead that a technical conference be convened to further examine the issues. The technical conference has yet to be scheduled.

PJM Market Reform: PJM Capacity Performance Proposal and 2015/2016 Reliability Filings

On December 12, 2014, PJM submitted two filings to implement its proposed "Capacity Performance" reform of the RPM capacity market. PJM proposes to revise the PJM Tariff to, among other things: (i) adopt a modified version of the FERC-approved ISO New England Inc. capacity performance payment structure; (ii) allow no excuses for nonperformance except under certain defined circumstances; (iii) maintain DR as a supply-side resource; and (iv) impose a Capacity Performance Resource must-offer requirement (units that can perform as a Capacity Performance Resource must offer into the capacity market, except certain defined resources, including DR). PJM also proposes, among other things, to revise the PJM Operating Agreement to provide limits in energy market offers based on specific physical characteristics and to ensure that capacity resources are available when the PJM Region needs them to perform. PJM requested an effective date of April 1, 2015 for these proposed reforms. Numerous parties filed comments on and protests to PJM's Capacity Performance filings. FESC, on behalf of its affected affiliates, and, as part of a coalition of certain other PJM utilities, filed comments and protests on the proposed reforms. PJM's filings and all related pleadings are pending before FERC.

In addition, on December 24, 2014, PJM submitted two filings seeking to ensure enough capacity is available during the 2015/2016 Delivery Year. First, PJM proposed to revise the PJM Tariff to allow PJM to procure an undetermined amount of additional capacity for the 2015/2016 Delivery Year to address reliability concerns. PJM requested an effective date of February 23, 2015 for this revision. Second, PJM requested a one-time PJM Tariff waiver that would permit PJM to keep approximately 2,000 MW of committed capacity that should be released for the third incremental auction for the 2015/2016 Delivery Year. Without the waiver, PJM would be required under the PJM Tariff to release this capacity. PJM requests an effective date of February 23, 2015 for the waiver. Numerous parties filed comments on and protests to these PJM filings. FESC, on behalf of its affected affiliates, and, as part of a coalition of certain other PJM utilities, filed comments in support of both PJM filings and seeking additional information from PJM about the scope of any capacity shortfall. PJM's filings and all related pleadings are pending before FERC.

PJM Market Reform: PJM RPM Auctions - Calculation of Unit-Specific Offer Caps

The PJM Tariff describes the rules for calculating the "offer cap" for each unit that offers into the RPM auctions. FES disagreed with the PJM Market Monitor's approach for calculating the offer caps and in 2014, FES asked FERC to determine which PJM Tariff interpretation, FES's or the PJM Market Monitor's, was correct. On August 25, 2014, FERC issued a declaratory order agreeing with the FES interpretation of the PJM Tariff language. FERC went on, however, to initiate a new proceeding to examine whether the existing PJM Tariff language is just and reasonable. PJM filed its brief explaining why the existing PJM Tariff language is just and reasonable. Other parties, including FES, submitted responsive briefs. The briefs and related pleadings are pending before FERC.

PJM Market Reform: FERC Order No. 745 - DR

On May 23, 2014, a divided three-judge panel of the U.S. Court of Appeals for the D.C. Circuit issued an opinion vacating FERC Order No. 745, which required that, under certain parameters, DR participating in organized wholesale energy markets be compensated at LMP. The majority concluded that DR is a retail service, and therefore falls under state, and not federal, jurisdiction, and that FERC, therefore, lacks jurisdiction to regulate DR. The majority also found that even if FERC had jurisdiction over DR, Order No. 745 would be arbitrary and capricious because, under its requirements, DR was inappropriately receiving a double payment (LMP plus the savings of foregone energy purchases). On January 15, 2015, FERC and a coalition of DR providers and industrial end-user groups filed separate petitions for U.S. Supreme Court review of the May 23, 2014 decision. Responses to those petitions are due March 19, 2015. The U.S. Court of Appeals for the D.C. Circuit will withhold issuance of the mandate pending the United States Supreme Court's disposition of those petitions.

On May 23, 2014, FESC, on behalf of its affiliates with market-based rate authorization, filed a complaint asking FERC to issue an order requiring the removal of all portions of the PJM Tariff allowing or requiring DR to be included in the PJM capacity market, with a refund effective date of May 23, 2014. FESC also requested that the results of the May 2014 PJM BRA be considered void and legally invalid to the extent that DR cleared that auction because the participation of DR in that auction was unlawful in light of the May 23, 2014 U.S. Court of Appeals for the D.C. Circuit decision discussed above. FESC, on behalf of FES, subsequently filed an amended complaint renewing its request that DR be removed from the May 2014 BRA. Specifically, FESC requested that FERC direct PJM to recalculate the results of the May 2014 BRA by: (i) removing DR from the PJM capacity supply pool; (ii) leaving the offers of actual capacity suppliers unchanged; and then (iii) determining which capacity suppliers clear the auction on the basis of the offers they submitted consistent with the existing PJM Tariff once the unlawful DR resources have been removed. The complaint remains pending before FERC. The timing of FERC action and the outcome of this proceeding cannot be predicted at this time.

On January 14, 2015, PJM filed proposed amendments to the PJM Tariff for the purpose of addressing the uncertainty of DR. The amendments, which will become effective only in certain defined conditions, purport to be in response to the U.S. Court of Appeals for the D.C. Circuit's May 23, 2014 decision regarding FERC's jurisdiction to regulate DR, as discussed above. If implemented, the amendments will move DR from the supply side to the load side for purposes of PJM's RPM capacity markets, and will permit loads to bid load reductions into the RPM auctions occurring after April 1, 2015. On February 13, 2015, FirstEnergy, as part of a coalition, filed a protest against PJM's proposed amendments. FirstEnergy expects further filings before FERC rules on this matter.

PJM Market Reform: PJM 2014 Triennial RPM Review

The PJM Tariff obligates PJM to perform a thorough review of its RPM program every three years. On September 25, 2014, PJM filed proposed changes to the PJM Tariff as part of the latest review cycle. Among other adjustments, the filing included: (i) shifting the VRR curve one percentage point to the right, which would increase the amount of capacity supply that is procured in the RPM auctions and the clearing price; and (ii) a change to the index used for calculating the generation plant construction costs of the Net CONE formula for the future years between triennial reviews. On November 28, 2014, FERC accepted the PJM Tariff amendments as proposed, subject to a minor compliance requirement. PJM subsequently submitted the required compliance filing. On December 23, 2014, a coalition including FESC, on behalf of its affected affiliates, requested rehearing of FERC's order. PJM's compliance filing, and the coalition's and others' requests for rehearing, remain pending before FERC.

Market-Based Rate Authority, Triennial Update

The Utilities, AE Supply, FES, FG, NG, FirstEnergy Generation Mansfield Unit 1 Corp., Buchanan Generation, LLC, and Green Valley Hydro, LLC each hold authority from FERC to sell electricity at market-based rates. One condition for retaining this authority is that every three years each entity must file an update with the FERC that demonstrates that each entity continues to meet FERC's requirements for holding market-based rate authority. On December 20, 2013, FESC, on behalf of its affiliates with market-based rate authority, submitted to FERC the most recent triennial market power analysis filing for each market-based rate holder for the current cycle of this filing requirement. On August 13, 2014, FERC accepted the triennial filing as submitted.

FERC Opinion No. 531

On June 19, 2014, FERC issued Opinion No. 531, in which FERC revised its approach for calculating the discounted cash flow element of FERC's ROE methodology, and announced a qualitative adjustment to the ROE methodology results. Under the old methodology, FERC used a five-year forecast for the dividend growth variable, whereas going forward the growth variable will consist of two parts: (a) a five-year forecast for dividend growth (2/3 weight); and (b) a long-term dividend growth based on a forecast for the U.S. economy (1/3 weight). Regarding the qualitative adjustment, FERC formerly pegged ROE at the mid-point of the "zone of reasonableness" that came out of the ROE formula, whereas going forward, FERC may rely on record evidence to make qualitative adjustments to the outcome of the ROE methodology in order to reach a level sufficient to attract future investment. Requests for rehearing of Opinion No. 531 are currently pending before FERC. On October 16, 2014, FERC issued its Opinion No. 531-A, applying the revised ROE methodology to certain ISO New England Inc. transmission owners. FirstEnergy is evaluating the potential impact of Opinion No. 531 on the authorized ROE of our FERC-regulated transmission utilities and the cost-of-service wholesale power generation transactions of MP.

Capital Requirements

Our capital spending for 2015 is expected to be approximately $2.9 billion, which includes approximately $970 million for Regulated Transmission. Planned capital initiatives are intended to promote reliability, improve operations, and support current environmental and energy efficiency directives.

Actual capital expenditures for 2014 and anticipated expenditures for 2015 are shown in the following table. Such costs include expenditures for the improvement of existing facilities and for the construction of transmission lines, distribution lines and substations, and other assets.

	2014 Actual[1]	2014 Pension/OPEB Mark-to-Market Capital Costs	2014 Actual Excluding Pension/OPEB Mark-to-Market Capital Costs	Capital Expenditures Forecast 2015[2][3]
		(In millions)		
OE	$ 212	$ 69	$ 143	$ 171
Penn	54	16	38	43
CEI	126	22	104	115
TE	55	18	37	44
JCP&L	306	84	222	267
ME	158	39	119	104
PN	182	42	140	153
MP	277	24	253	273
PE	141	16	125	106
WP	168	33	135	143
ATSI	933	—	933	560
TrAIL	242	—	242	249
FES	673	14	659	508
AE Supply	62	—	62	94
Other subsidiaries	96	10	86	112
Total	$ 3,685	$ 387	$ 3,298	$ 2,942

(1) Includes an increase of approximately $387 million related to the capital component of the pension and OPEB mark-to-market adjustment.
(2) Excludes the capital component for pension and OPEB mark-to-market adjustments, which cannot be estimated.
(3) At the Bruce Mansfield Power Station, while the plant continues to operate, if market reforms prove unsatisfactory and market conditions remain unfavorable, FirstEnergy may continue to minimize certain capital expenditures at the plant, including the delay of the new water treatment upgrades necessary for the continued operation of the plant after the LBR CCR Impoundment closes on December 31, 2016, which would reduce planned capital expenditures at FES.

The following table presents scheduled debt repayments for outstanding long-term debt as of December 31, 2014, excluding capital leases for the next five years. PCRBs that can be tendered for mandatory purchase prior to maturity are reflected in 2015.

	2015	2016-2019	Total
		(In millions)	
FirstEnergy	$ 769	$ 6,835	$ 7,604
FES	$ 501	$ 1,402	$ 1,903

The following tables display consolidated operating lease commitments as of December 31, 2014.

Operating Leases	Lease Payments	FirstEnergy PNBV[1]	Net
		(In millions)	
2015	$ 245	$ 40	$ 205
2016	197	13	184
2017	122	3	119
2018	128	—	128
2019	109	—	109

Years thereafter	1,482	—	1,482
Total minimum lease payments	$ 2,283	$ 56	$ 2,227

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

Operating Leases	**FES**
	(In millions)
2015	$ 142
2016	131
2017	81
2018	101
2019	97
Years thereafter	1,383
Total minimum lease payments	$ 1,935

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. FE's primary source of cash for continuing operations as a holding company is cash from the operations of its subsidiaries. During 2014, FirstEnergy received $735 million of cash dividends and capital returned from its subsidiaries and paid $604 million in cash dividends to common shareholders. In addition to internal sources to fund liquidity and capital requirements for 2015 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. In the future, FirstEnergy may consider additional equity to fund capital investments in the Regulated Transmission business.

FE and certain of its subsidiaries participate in three five-year syndicated revolving credit facilities with aggregate commitments of $6.0 billion (Facilities), which are available until March 31, 2019. FirstEnergy had $1,799 million and $3,404 million of short-term borrowings under the Facilities as of December 31, 2014 and 2013, respectively. FirstEnergy's available liquidity under the Facilities as of January 31, 2015 was $3,962 million.

In January 2015, FirstEnergy's Board of Directors declared a quarterly dividend of $0.36 per share of outstanding common stock. The dividend is payable March 1, 2015, to shareholders of record at the close of business on February 6, 2015. This dividend equates to an indicated annual dividend of $1.44 per share and is consistent with the dividends declared in 2014.

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 an opportunity for a hearing on the Davis-Besse license renewal application to a group of Intervenors, subject to admissible contentions. On September 29, 2014, the Intervenors filed a petition, accompanied by a request to admit a new contention, to suspend the final licensing decision on Davis-Besse license renewal. These filings argue that the NRC's Continued Storage Rule failed to make necessary safety findings regarding the technical feasibility of spent fuel disposal and the adequacy of future repository capacity required by the Atomic Energy Act. On October 31, 2014, FENOC and the NRC Staff filed their opposition to these requests.

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, 2014, FirstEnergy had approximately $2.3 billion invested in external trusts to be used for the decommissioning and environmental remediation of Davis-Besse, Beaver Valley, Perry and TMI-2. The values of FirstEnergy's NDTs 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 NDTs. By a letter dated July 2, 2014, FENOC submitted a $155 million FES parental guaranty relating to a shortfall in nuclear decommissioning funding for Beaver Valley Unit 1 and Perry to the NRC for approval. FE and FES have also entered into a total of $23 million in parental guaranties in support of the decommissioning of the spent fuel storage facilities located at the nuclear facilities. As required by the NRC, FirstEnergy annually recalculates and adjusts the amount of its parental guaranties, as appropriate.

As part of routine inspections of the concrete shield building at Davis-Besse in 2013, FENOC identified changes to the subsurface laminar cracking condition originally discovered in 2011. These inspections revealed that the cracking condition had propagated a small amount in select areas. FENOC's analysis confirms that the building continues to maintain its structural integrity, and its ability to safely perform all of its functions. On September 2, 2014, the Intervenors in the Davis-Besse license renewal proceeding requested that the ASLB introduce issues based on FENOC's plans to manage the subsurface laminar cracking in the Davis-Besse shield building. On January 15, 2015, the ASLB denied this request. The NRC continues to evaluate FENOC's analysis of the shield building.

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.

Nuclear Insurance

The Price-Anderson Act limits the public liability which can be assessed with respect to a nuclear power plant to $13.6 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) $13.2 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 $127 million (but not more than $19 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 $509 million (NG-$501 million) per incident but not more than $76 million (NG-$75 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 annually, corresponding to their respective nuclear interests, which provide an aggregate indemnity of up to approximately \$1.96 billion (NG-\$1.93 billion) for replacement power costs incurred during an outage after an initial 20-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 (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 \$74 million (NG-\$72 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.

Clean Air Act

FirstEnergy complies with SO_2 and NOx emission 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. 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 D.C. Circuit decided that CAIR violated the CAA but allowed CAIR to remain in effect to "temporarily preserve its environmental values" until the EPA replaced 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 D.C. Circuit and was ultimately vacated by the Court on August 21, 2012. The Court subsequently ordered the EPA to continue administration of CAIR until it finalized a valid replacement for CAIR. On April 29, 2014, the U.S. Supreme Court reversed the U.S. Court of Appeals for the D.C. Circuit decision vacating CSAPR and generally upheld the EPA's authority under the CAA to establish the regulatory structure underpinning CSAPR. On October 23, 2014, the U.S. Court of Appeals for the D.C. Circuit lifted its stay of CSAPR allowing its Phase 1 reductions of NOx and SO_2 emissions to begin in 2015, a three year delay from EPA's original rule. CSAPR Phase 2 will also be delayed by three years to 2017. Depending on the outcome of further proceedings in this matter and how the EPA and the states implement the final rules, the future cost of compliance may be substantial and changes to FirstEnergy's and FES' operations may result.

MATS imposes 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 extension through April 16, 2016 for MATS compliance at the Fort Martin, Harrison and Pleasants stations. On March 20, 2013, the PA

DEP granted an extension through April 16, 2016 for MATS compliance at the Hatfield's Ferry and Bruce Mansfield stations. In December 2014, FG requested an extension through April 16, 2016 for MATS compliance at the Bay Shore and Sammis stations and await a decision from OEPA. 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 was challenged in the U.S. Court of Appeals for the D.C. Circuit by various entities, including FirstEnergy's challenge of the PM emission limit imposed on petroleum coke boilers, such as Bay Shore Unit 1. On April 15, 2014, MATS was upheld by the U.S. Court of Appeals for the D.C. Circuit, however, the Court refused to decide

FirstEnergy's challenge of the PM emission limit imposed on petroleum coke boilers due to a January 2013 petition for reconsideration still pending but not addressed by EPA. On November 25, 2014, the U.S. Supreme Court agreed to review MATS, specifically, to determine if EPA should have evaluated the cost of MATS prior to regulating. Depending on the outcome of the U.S. Supreme Court review and how the MATS are ultimately implemented, FirstEnergy's total capital cost for compliance (over the 2012 to 2018 time period) is currently expected to be approximately $370 million (CES segment of $178 million and Regulated Distribution segment of $192 million), of which $133 million has been spent through 2014 ($56 million at CES and $77 million at Regulated Distribution).

As of September 1, 2012, Albright, Armstrong, Bay Shore Units 2-4, Eastlake Units 4-5, R. Paul Smith, Rivesville and Willow Island were deactivated. FG entered into RMR arrangements with PJM for Eastlake Units 1-3, Ashtabula Unit 5 and Lake Shore Unit 18 through the spring of 2015, when they are scheduled to be deactivated. In February 2014, PJM notified FG that Eastlake Units 1-3 and Lake Shore Unit 18 will be released from RMR status as of September 15, 2014. FG intends to operate the plants through April 2015, subject to market conditions. As of October 9, 2013, the Hatfield's Ferry and Mitchell stations were also deactivated.

FirstEnergy and FES have various long-term coal supply and transportation agreements, some of which run through 2025 and certain of which are related to the plants described above. FE and FES have asserted force majeure defenses for delivery shortfalls under certain agreements, and are in discussion with the applicable counterparties. As to coal transportation agreements, FE and FES have agreed to pay liquidated damages for delivery shortfalls for 2014 in the estimated amount of $70 million. If FE and FES fail to reach a resolution with the applicable counterparties for the agreements associated with the deactivated plants or unresolved aspects of the agreements and it were ultimately determined that, contrary to their belief, the force majeure provisions or other defenses, do not excuse or otherwise mitigate the delivery shortfalls, the results of operations and financial condition of both FirstEnergy and FES could be materially adversely impacted. If that were to occur, FE and FES are unable to estimate the loss or range of loss. Additionally, on July 1, 2014, FES terminated a long-term fuel supply agreement. In connection with this termination, FES recognized a pre-tax charge of $67 million in the second quarter of 2014. In one coal supply agreement, AE Supply has asserted termination rights effective in 2015. In response to the notification of the termination, the coal supplier has commenced litigation alleging AE Supply does not have sufficient justification to terminate the agreement. There are 6 million tons remaining under the contract for delivery. At this time, FirstEnergy cannot estimate the loss or range of loss regarding the on-going litigation with respect to this agreement.

In June 2005, the PA DEP and the Attorneys General of New York, New Jersey, Connecticut and Maryland filed suit against AE, AE Supply, MP, PE and WP in the U.S. District Court for the Western District of Pennsylvania alleging, among other things, that AE performed major modifications in violation of the NSR provisions of the CAA and the Pennsylvania Air Pollution Control Act at the coal-fired Hatfield's Ferry, Armstrong and Mitchell Plants in Pennsylvania. On February 6, 2014, the Court entered judgment for AE, AE Supply, MP, PE and WP finding they had not violated the CAA or the Pennsylvania Air Pollution Control Act. New York, Connecticut, and Maryland withdrew their appeal to the U.S. Court of Appeals for the Third Circuit on December 15, 2014, concluding this litigation. This decision does not change the status of these plants which remain deactivated.

In September 2007, AE received an 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. The EPA's NOV alleges equipment replacements during maintenance outages triggered the pre-construction permitting requirements under the NSR and PSD programs. On June 29, 2012, January 31, 2013, and March 27, 2013, EPA issued 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. On December 12, 2014, EPA issued a CAA section 114 request for the Fort Martin coal-fired plant seeking information and documentation relevant to its operation and maintenance, including capital projects undertaken since 2009. FirstEnergy 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 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.

Climate Change

There are a number of initiatives to reduce GHG emissions at the state, federal and international level. Certain northeastern states are participating in the RGGI and western states led by California, have implemented programs, primarily cap and trade mechanisms, to control emissions of certain GHGs. Additional policies reducing GHG emissions, such as demand reduction programs, renewable portfolio standards and renewable subsidies have been implemented across the nation. A June 2013, Presidential Climate Action Plan outlined goals to: (1) cut carbon pollution in America by 17% by 2020 (from 2005 levels); (2) prepare the United States for the impacts of climate change; and (3) lead international efforts to combat global climate change and prepare for its impacts. GHG emissions have already been reduced by 10% between 2005 and 2012 according to an April, 2014 EPA Report. In a joint announcement on November 12, 2014, President Obama stated a U.S. target of reducing GHG emissions by 26 to 28% by 2025 from 2005 emission levels and China's President stated its GHG emissions will "peak", around 2030 with approximately 20% of its energy generated by non-fossil fuels by that same year. Due to plant deactivations and increased efficiencies, FirstEnergy anticipates its CO_2 emissions will be reduced 25% below 2005 levels by 2015, exceeding the President's Climate Action Plan goals both in terms of timing and reduction levels.

EPA released its final "Endangerment and Cause or Contribute Findings for Greenhouse Gases under the Clean Air Act" in December 2009, concluding that concentrations of several key GHGs constitutes an "endangerment" and may be regulated as "air pollutants" under the CAA and mandated measurement and reporting of GHG emissions from certain sources, including electric generating plants. EPA proposed a new source performance standard in September 2013, which would not apply to any existing, modified, or reconstructed fossil fuel generating units, of 1,000 lbs. CO_2/MWH for large natural gas fired units (> 850 mmBTU/hr), and 1,100 lbs. CO_2/MWH for other natural gas fired units (≤ 850 mmBTU/hr), and 1,100 lbs. CO_2/MWH for fossil fuel fired units which would require partial carbon capture and storage. EPA proposed regulations in June 2014, to reduce CO_2 emissions from existing fossil fuel electric generating units that would require each state to develop state implementation plans by June 30, 2016, to meet EPA's state specific CO_2 emission rate goals. EPA's proposal allows states to request a 1-year extension for single-SIPs (June 30, 2017) or a 2-year extension for multi-state SIPs (June 30, 2018). EPA also proposed separate regulations imposing additional CO_2 emission limits on modified and reconstructed fossil fuel electric generating units. On January 7, 2015, EPA announced it would complete all of these so-called "Carbon Pollution Standards" by "midsummer" 2015. On June 23, 2014, the U.S. Supreme Court decided that CO_2 or other GHG emissions alone cannot trigger permitting requirements under the CAA, but that air emission sources that need PSD permits due to other regulated air pollutants can be required by EPA to install GHG control technologies. On November 13, 2014, the U.S. Court of Appeals for the D.C. Circuit scheduled expedited briefing to consider challenges to prevent EPA from regulating CO_2 emissions from existing fossil fuel electric generating units. Depending on the outcome of appeals and how any final rules are ultimately implemented, the future cost of compliance may be substantial.

At the international level, the United Nations Framework Convention on Climate Change resulted in the Kyoto Protocol requiring participating countries, which does not include the U.S., to reduce GHGs commencing in 2008 and has been extended through 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.

The EPA finalized CWA Section 316(b) regulations in May 2014, requiring cooling water intake structures with an intake velocity greater than 0.5 feet per second to reduce fish impingement when aquatic organisms are pinned against screens or other parts of a cooling water intake system to a 12% annual average and requiring cooling water intake structures exceeding 125 million gallons per day to conduct studies to determine site-specific controls, if any, to reduce entrainment, which occurs when aquatic life is drawn into a facility's cooling water system. 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 cooling water intake channel to divert fish away from the plant's cooling water intake system. Depending on the results of such studies and any final action taken by the states based on those studies, the future costs of compliance with these standards may require material capital expenditures.

The EPA proposed updates to the waste water effluent limitations guidelines and standards for the Steam Electric Power Generating category (40 CFR Part 423) in April 2013. The EPA proposed eight treatment options for waste water discharges from electric power plants, of which four are "preferred" by the agency. The preferred options range from more stringent chemical and biological treatment requirements to zero discharge requirements. The EPA is required to finalize this rulemaking by September 30, 2015, under a consent decree entered by a U.S. District Court and the treatment obligations are proposed to phase-in as permits are renewed on a 5-year cycle from 2017 to 2022. Depending on the content of the EPA's final rule and any final action taken by the states, the future costs of compliance with these standards may require material capital expenditures.

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 ranging from $150 million to $300 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 recommended a sulfate impairment designation for an approximately 68 mile stretch of the Monongahela River north of the West Virginia border which EPA approved in May of 2011. PA DEP subsequently recommended that the sulfate impairment designation for the Monongahela River be removed in its bi-annual water report. The EPA approved the removal of the sulfate impairment designation for the Monongahela River on December 19, 2014.

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 RCRA, as amended, and the Toxic Substances Control Act. Certain coal 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 2014, the EPA finalized regulations for the disposal of CCRs (non-hazardous), establishing national standards regarding landfill design, structural integrity design and assessment criteria for surface impoundments, groundwater monitoring and protection procedures and other operational and reporting procedures to assure the safe disposal of CCRs from electric generating plants. Depending on how the final rules are ultimately implemented, the future costs of compliance with such CCR regulations may require material capital expenditures.

The PA DEP filed a 2012 complaint against FG in the U.S. District Court for the Western District of Pennsylvania with claims under the RCRA and Pennsylvania's Solid Waste Management Act regarding the LBR CCR Impoundment and simultaneously proposed a consent decree between PA DEP and FG to resolve those claims. On December 14, 2012, a modified consent decree 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 required payment of civil penalties of $800,000 to resolve claims under the Solid Waste Management Act. PA DEP issued a 2014 permit requiring FE to provide bonding for 45 years of closure and post-closure activities and to complete closure within a 12-year period, but authorizing FE to seek a permit modification based on "unexpected site conditions that have or will slow closure progress." The permit does not require active dewatering of the CCRs, but does require a groundwater assessment for arsenic and abatement if certain conditions in the permit are met. The Bruce Mansfield Plant is pursuing several options for its CCRs following December 31, 2016. A 2013 complaint filed by Citizens Coal Counsel and other NGOs in the U.S. District Court for the Western District of Pennsylvania, against the owner and operator of a reclamation mine in LaBelle, Pennsylvania that is one possible alternative, alleged the LaBelle site is in violation of RCRA and state laws. On July 14, 2014, Citizens Coal Council served FE, FG and NRG with a citizen suit notice alleging violations of RCRA due to beneficial reuse of "coal ash" at the LaBelle Site.

On October 10, 2013 approximately 61 individuals filed a complaint against FG in the U.S. District Court for the Northern District of West Virginia seeking damages for alleged property damage, bodily injury and emotional distress related to the LBR CCR Impoundment. The complaints state claims for private nuisance, negligence, negligence per se, reckless conduct and trespass related to alleged groundwater contamination and odors emanating from the Impoundment. FG believes the claims are without merit and intends to vigorously defend itself against the allegations made in the complaints, but, at this time, is unable to predict the outcome of the above matter or estimate the possible loss or range of loss. A similar complaint involving approximately 26 individuals filed in the U.S. District Court for the Western District of Pennsylvania has been resolved and was closed on February 9, 2015, pending the filing of a stipulation for dismissal.

FirstEnergy and certain of its subsidiaries 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, 2014 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 $125 million have been accrued through December 31, 2014. Included in the total are accrued liabilities of approximately $85 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 25.4 million tons of coal for the year 2015 which is approximately 100% of its estimated 2015 coal requirements. This contract coal is produced primarily from mines located in Ohio, Pennsylvania, West Virginia, Montana and Wyoming. The contracts expire at various times through

December 31, 2030. See Environmental Matters for factors pertaining to meeting environmental regulations affecting coal-fired generating units.

FirstEnergy has contracts for all uranium requirements through 2018 and a portion of uranium material requirements through 2024. Conversion services contracts fully cover requirements through 2018 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 2020 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 currently adequate for all FENOC operating units. An on-site dry cask storage facility has been constructed at Beaver Valley sufficient to extend spent fuel storage capacity through the end of current operating licenses at Beaver Valley Unit 1 (2036) and Beaver Valley Unity 2 (2047). Davis-Besse is planning to resume dry cask storage operations in 2017 which will extend on-site spent fuel storage capacity through 2037 (end of current operating license plus a 20-year operating license extension). Perry completed plant modification for dry cask storage in 2012, loaded spent fuel into dry cask storage in 2012 and 2014 (referred to as a loading campaign), and has planned to conduct additional dry cask storage loading campaigns that will provide for sufficient spent fuel storage capacity through 2046 (end of current operating license plus a 20-year operating license extension).

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. The current Administration has stated the Yucca Mountain repository will not be completed and a Federal review of potential alternative strategies has been performed.

In light of this uncertainty, FirstEnergy has made arrangements for storage capacity as a contingency for the continuing delays of the DOE acceptance of spent fuel for disposal.

In November, 2013, the DOE was ordered by the U.S. Court of Appeals for the D.C. Circuit to move forward to end the fee of 1 mill per KWH utilities pay for nuclear waste disposal because the government has no defined solution as an alternative to the canceled Yucca Mountain repository. This ruling was issued due to the DOE's failure to establish a court ordered assessment to validate the appropriateness of the fee in the wake of the cancellation of the Yucca Mountain repository. Collection of the fee was suspended in May 2014.

Fuel oil and natural gas are used primarily to fuel peaking units and/or to ignite the burners prior to burning coal when a coal-fired plant is restarted. Fuel oil requirements have historically been low and are forecasted to remain so. Requirements are expected to average approximately 5 million gallons per year over the next five years. Natural gas demand at the combined cycle and peaking units is forecasted at approximately 27 million cubic feet in 2015.

System Demand

The 2014 maximum hourly demand for each of the Utilities was:

- OE—5,294 MW on September 5, 2014;
- Penn—854 MW on September 5, 2014;
- CEI—4,117 MW on September 5, 2014;
- TE—2,097 MW on September 5, 2014;
- JCP&L—5,624 MW on July 2, 2014;
- ME—2,705 MW on July 2, 2014;
- PN—2,699 MW on July 2, 2014;
- MP—1,916 MW on January 7, 2014;
- PE—3,357 MW on January 7, 2014; and
- WP—4,075 MW on January 7, 2014.

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 CES segment, through FES and AE Supply, primarily 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 NERC in accordance with a Delegation Agreement approved by FERC.

Competition

Within FirstEnergy's Regulated Distribution segment, generally there is no competition for electric distribution service in the Utilities' respective service territories in Ohio, Pennsylvania, West Virginia, Maryland, New Jersey and New York. Additionally, there has traditionally been no competition for transmission service in PJM. However, competition for non-incumbent transmission facilities in the service territory of FirstEnergy's Regulated Transmission segment is now permitted pursuant to FERC's Order No. 1000, subject to state and local siting and permitting approvals. This could result in additional competition to build transmission lines in the Regulated Transmission segment's service territory while also allowing the Regulated Transmission segment the opportunity to seek to build facilities in other service territories.

FirstEnergy's CES segment participates in deregulated energy markets in Ohio, Pennsylvania, Maryland, Michigan, New Jersey and Illinois, through FES and AE Supply. In these markets, the CES 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, FENOC and ATSI 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 programs and projects are directed toward business solutions and their applications to problems 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 17, 2015

Name	Age	Positions Held During Past Five Years	Dates
A. J. Alexander	63	Executive Chairman of the Board (A)	2015-present
		Chief Executive Officer (F)	*-2015
		President and Chief Executive Officer (A)(B)	*-2014
L. M. Cavalier	63	Senior Vice President, Human Resources (B)	*-present
M. J. Dowling	50	Senior Vice President, External Affairs (B)	2011-present
		Vice President, External Affairs (B)	2010-2011
		Vice President, Communications (B)	* - 2010
B. L. Gaines	61	Senior Vice President, Corporate Services and Chief Information Officer (B)	2012-present
		Vice President, Corporate Services and Chief Information Officer (B)	2011-2012
		Vice President, Shared Services, Administration and Chief Information Officer (B)	*-2011
C. E. Jones	59	President and Chief Executive Officer (A)(B)	2015-present
		Chief Executive Officer (F)	2015-present
		Executive Vice President & President, FirstEnergy Utilities (A)(B)	2014
		Senior Vice President & President, FirstEnergy Utilities (B)	2010-2013
		President (H)(I)	2011-2015
		President (C)(D)(L)	2010-2015
		Senior Vice President & President, FirstEnergy Utilities (A)	2010-2011
		Senior Vice President, Energy Delivery & Customer Service (B)	*-2010
		Senior Vice President (C)(D)	*-2010
J. H. Lash	64	President, FE Generation (B)	2011-present
		President (G)(J)	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	60	Senior Vice President and Chief Financial Officer (A)(B)(C)(D)(E)(F)(G)(H)(I)(J)(L)	2013-present
		Senior Vice President and Treasurer (A)(B)(C)(D)(E)(F)(G)(H)(I)(J)(L)	2012
		Vice President and Treasurer (A)(B)(C)(D)(E)(F)(J)(L)	*-2012
		Vice President and Treasurer (G)(H)(I)	2011-2012
D. R. Schneider	53	President (E)	*-present
S. E. Strah	51	Senior Vice President & President, FirstEnergy Utilities (B)	2015-present
		President (C)(D)(H)(I)(L)	2015-present
		Vice President, Distribution Support (B)	2011-2015
		Regional President (K)	*-2011
K. J. Taylor	41	Vice President, Controller and Chief Accounting Officer (A)(B)	2013-present
		Vice President and Controller (C)(D)(E)(F)(G)(H)(I)(J)(L)	2013-present
		Vice President and Assistant Controller (A)(B)(C)(D)(E)(F)(G)(H)(I)(J)(L)	2012-2013
		Assistant Controller (A)(B)(C)(D)(L)	2010-2012
		Assistant Controller (H)(I)	2011-2012

		Assistant Controller (E)(F)(G)(J)	2012
		Manager, Financial Reporting & Technical Accounting (B)	*-2010
L. L. Vespoli	55	Executive Vice President, Markets & Chief Legal Officer (A)(B)(C)(D)(E)(F)(G)(H)(I)(J)(L)	2014-present
		Executive Vice President and General Counsel (A)(B)(C)(D)(E)(F)(J)(L)	*-2013
		Executive Vice President and General Counsel (G)(H)(I)	2011-2013

* Indicates position held at least since January 1, 2010
(A) Denotes executive officer of FE
(B) Denotes executive officer of FESC
(C) Denotes executive officer of OE, CEI and TE
(D) Denotes executive officer of ME, PN and Penn
(E) Denotes executive officer of FES
(F) Denotes executive officer of FENOC
(G) Denotes executive officer of AGC
(H) Denotes executive officer of MP, PE and WP
(I) Denotes executive officer of TrAIL and FET
(J) Denotes executive officer of FG
(K) Denotes executive officer of OE
(L) Denotes executive officer of ATSI

Employees

As of December 31, 2014, FirstEnergy's subsidiaries had 15,557 employees located in the United States as follows:

	Total Employees	Bargaining Unit Employees
FESC [1]	3,979	590
OE	1,095	722
CEI	858	573
TE	333	238
Penn	191	144
JCP&L	1,348	1,047
ME	644	489
PN	753	503
FES	143	—
FG	1,935	1,169
FENOC	2,638	1,103
MP	520	334
PE	449	271
WP	671	429
Total	**15,557**	**7,612**

[1] As of December 31, 2014, ATSI employees were transferred to FESC.

As of December 31, 2014, the IBEW, the UWUA and the OPEIU unions collectively represented approximately 49% of FirstEnergy's total employees. There are various CBAs between FirstEnergy's subsidiaries and these unions, most of which have three year terms. In 2014, certain of FirstEnergy's subsidiaries reached agreements on CBAs for seven UWUA locals and three IBEW locals, covering approximately 2,978 employees. These contracts will expire in 2017, 2018 and 2019.

On August 7, 2014, UWUA Local 180, which represents approximately 140 employees at PN and was previously working under an expired CBA, notified PN that its members ratified a new CBA expiring in 2017. Also, on August 7, 2014, UWUA Local 304, which represents approximately 160 employees at the Harrison generating facility and was previously working without a CBA, ratified a new CBA expiring in 2018. The CBA with IBEW Local 272, which represents approximately 300 employees at the Bruce Mansfield Plant, expired on February 16, 2014. FirstEnergy continues to engage in negotiations with Local 272, and work continuation plans are in place in the event of a work stoppage. On September 24, 2014, IBEW Local 29, which represents approximately 500 employees at the Beaver Valley Power Station, ratified a new CBA expiring in 2018. On October 17, 2014, UWUA Locals 118 and 126, which represent approximately 400 employees at OE, ratified a new CBA expiring in 2020. On October 28, 2014, UWUA Local 140, which represents approximately 140 employees at Penn, ratified a new CBA expiring in 2020. On December 18, 2014, UWUA Local 102, which represents approximately 700 employees at WP and PE, ratified the companies' offer of a CBA expiring in 2019.

FirstEnergy Web Site and Other Social Media Sites and Applications

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 the "Investors" page of FirstEnergy's Internet web site at www.firstenergycorp.com.

These SEC filings are posted on the web site as soon as reasonably practicable after they are electronically filed with the SEC. Additionally, the registrants routinely post additional important information including press releases, investor presentations and notices of upcoming events, under the "Investors" section of 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. Investors may be notified of postings to the web site by signing up for email alerts and RSS feeds on the "Investors" page of FirstEnergy's Internet web site or through push alerts from FirstEnergy Investor Relations apps for Apple Inc.'s iPad® and iPhone® devices, which can be installed for free at the Apple® online store. FirstEnergy also uses Twitter® and Facebook® as additional channels of distribution to reach public investors and as a supplemental means of disclosing material non-public information for complying with its disclosure obligations under SEC Regulation FD. Information contained on FirstEnergy's Internet web site or its Twitter® or Facebook® site, and any corresponding applications of those sites, 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

We Have Taken a Series of Actions to Reposition our Asset Mix to Reflect a More Regulated Business Profile Focusing on Growing Our Regulated Distribution and Regulated Transmission Operations and Earnings. Whether This Repositioning Will Deliver the Desired Result is Subject to Certain Risks Which Could Adversely Affect Profitability and our Financial Condition in the Future

As a result of continuing weak economic conditions and depressed energy prices across our multi-state business territory, we have implemented a strategy to capitalize on investment opportunities available to our regulated operations - particularly in transmission. This strategy will involve continuing to reposition our asset mix over the next several years to reflect a more regulated business profile, and to target more than 80% of our earnings from our Regulated Distribution and Regulated Transmission segments. In connection with this repositioning, we initiated distribution rate cases for certain of our distribution utility subsidiaries and announced plans to grow our regulated transmission business, focusing first on ATSI and extending throughout our service area over time.

The success of our repositioning strategy will depend, in part, on successful recovery of our transmission investments. Factors that may affect rate recovery of our transmission investments may include: (1) whether the investments are included in PJM's RTEP; (2) FERC's evolving policies with respect to incentive rates for transmission assets; (3) FERC's evolving policies with respect to the base ROE component of transmission rates, as articulated in FERC's recent Opinion No. 531; (4) consideration of the objections of those who oppose such investments and their recovery; and (5) timely development, construction, and operation of the new facilities.

The success of this repositioning strategy will also depend, in part, on our achieving positive outcomes in distribution rate cases and transmission rate filings we have filed or will file. Any denial of, or delay in, any distribution or transmission rate request could restrict us from fully recovering our cost of service, may impose risk on operations, and could have a material adverse effect on our regulatory strategy.

Our repositioning strategy also could be impacted by our ability to finance the proposed expansion projects while maintaining adequate liquidity. There can be no assurance that the repositioning of our business to focus on our Regulated Distribution and Regulated Transmission segments will deliver the desired result which could adversely affect our profitability and financial condition.

We Are Subject to Risks Arising from the Operation 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, human error in operations or maintenance, 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, OE and TE 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, OE and TE have a maximum exposure to loss under those provisions of approximately $1.2 billion for FES, $429 million for OE and $231 million for TE. In addition, new and certain existing environmental requirements may force us to shut down such generating facilities or change their operating status, either temporarily or permanently, if we are unable to comply with such environmental requirements, or if we make a determination that the expenditures required to comply with such requirements are uneconomical.

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 short or long-term market price of electricity, which are affected by changes in other commodity costs and other factors including, but not limited to, weather, energy efficiency mandates, DR initiatives and deactivations and retirements at power production facilities, 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 in which 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, deterioration or weakness in the global economy has led to lower international demand for coal, oil and natural gas, which has lowered fossil fuel prices and may put downward pressure on electricity prices.

We Are Exposed to Operational, Price and Credit Risks Associated With Marketing and Selling 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 rate 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, including significant new penalties if PJM's market reforming Capacity Performance proposal is accepted as filed. 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 their 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 exposure 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, actual events may 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 the creditworthiness of counterparties, 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.

Nuclear Generation Involves Risks that Include Uncertainties Relating to Health and Safety, Additional Capital Costs, the Adequacy of Insurance Coverage and Nuclear Plant Decommissioning, Which Could Have a Material Adverse Effect on Our Business, Results of Operations and Financial Condition

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, including loss of life, 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, including any incidents of unplanned radiological release, 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 and increases in minimum funding requirements or costs of decommissioning.

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. Any one of these risks relating to our nuclear generation could have a material adverse effect on our business, results of operations and financial condition.

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, such proceedings relating to 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 a material adverse 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 a material adverse 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 CCRs

Approximately 55% of FirstEnergy's generation fleet capacity is coal-fired. Historically, coal-fired generating plants have greater exposure to the costs of complying with federal, state and local environmental statutes, rules and regulations relating to air emissions, including GHGs, and CCR disposal, than other types of electric generation facilities. These legal requirements and any future initiatives could impose substantial additional costs 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 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 pension and other obligations, requires significant judgment and actual results may differ significantly from current estimates. Capital market conditions that generate investment losses or that negatively impact the discount rate and increase the present value of liabilities may have significant impacts on the value of the pension, decommissioning and other trust funds, which could 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

Owners, operators, and users of the bulk electric system are subject to mandatory reliability standards promulgated by NERC and approved by FERC. 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 million per day for failure to comply with these mandatory electric reliability standards.

In addition to direct regulation by FERC, 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 that are quasi-regulatory in nature and can have a material adverse impact on our business. For example, the independent market monitors of ISOs and RTOs may impose bidding and scheduling rules to curb the perceived potential for exercise of market power and to ensure the market functions appropriately. 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 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 that we may be unable to recover fully or at all.

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 supply and transportation needs, some of which run through 2028 and certain of which relate to deactivated plants. We have asserted force majeure defenses for delivery shortfalls under certain agreements and are in discussions with the applicable counterparties. In one coal supply agreement, FirstEnergy, through a subsidiary, has also asserted termination rights effective in 2015 and is in litigation with the counterparty. We can provide no assurance that these discussions will be favorably resolved with respect to certain unresolved aspects of the agreements or that the litigation will be favorably resolved. If we fail to reach a resolution with the applicable counterparties and if it were ultimately determined that, contrary to our belief, the force majeure provision or other defenses, do not excuse or otherwise mitigate the delivery shortfalls, or if the litigation were resolved unfavorably, the results of operations and financial condition of both FirstEnergy and FES could be materially adversely impacted. In addition, we may from time to time enter into new contracts, or renegotiate certain of these contracts, but can provide no assurance that such contracts will be negotiated or renegotiated, as the case may be, on satisfactory terms, or at all. In addition, if prices for physical delivery are unfavorable, our financial condition, results of operations and cash flows could be materially adversely affected.

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

Weather conditions directly influence the demand for electric power. Demand for power generally peaks during the summer and winter months, with market prices also typically peaking at that time. Overall operating results may fluctuate based on weather conditions. In addition, we have historically sold less power, and consequently received less revenue, when weather conditions are milder. Severe weather, such as tornadoes, hurricanes, ice or snowstorms, or droughts or other natural disasters, may cause outages and property damage that may require us to incur additional costs that are generally not insured and that may not be recoverable from customers. The effect of the failure of our facilities to operate as planned under these conditions would be particularly burdensome during a peak demand period 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 DR 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 impact 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 industries in our business territories, e.g. shale gas, automotive, chemical, steel and other heavy industries, and as these conditions change, our revenues will be impacted. Additionally, the primary market areas of our CES segment overlap, to a large degree, with our Utilities' territories and hence its revenues are substantially impacted by the same economic conditions.

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

We had approximately $6.4 billion of recorded goodwill on our consolidated balance sheet as of December 31, 2014, of which $800 million is attributable to our CES segment. Recorded goodwill is tested for impairment annually or whenever events or changes in circumstances indicate impairment may have occurred. Key assumptions incorporated in the estimated cash flows used for the impairment analysis requiring significant management judgment include: discount rates, growth rates, future energy and capacity pricing, projected operating income, changes in working capital, projected capital expenditures, projected funding of pension plans, expected results of future rate proceedings, the impact of pending carbon and other environmental legislation and terminal multiples. Although the annual goodwill impairment test in 2014 resulted in a conclusion that goodwill is not impaired, the fair value of the CES reporting unit exceeded its carrying value by approximately 10%, impacted by near term weak economic conditions and low energy and capacity prices. We are unable to predict whether future impairment charges to goodwill may be necessary. In addition, we also review our long-lived assets for impairment when circumstances indicate the carrying value of these assets may not be recoverable. We are unable to predict whether impairment charges on one or more of our long-lived assets may occur in the future. The actual timing and amounts of any impairments to recorded goodwill or any long-lived assets in the future 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. A determination that recorded goodwill or any long-lived assets are deemed to be impaired would result in a non-cash charge that could materially adversely affect our results of operations and total capitalization.

We Face Certain Human Resource Risks Associated with Potential Labor Disruptions and/or 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. Further, a significant number of our physical workforce are represented by unions and while we believe that our relations with our employees are generally fair, we cannot provide assurances that the company will be completely free of labor disruptions such as work stoppages, work slowdowns, union organizing campaigns, strikes, lockouts or that any labor disruption will be favorably resolved. 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.

Security Breaches, Including Cybersecurity Breaches, and Other Disruptions Could Compromise Our Business Operations and Critical and Proprietary Information and Expose Us to Liability, Which Could Adversely Affect our Business, Financial Condition and Reputation

In the ordinary course of our business, we store sensitive data, intellectual property and proprietary information regarding our business, employees, shareholders, customers, suppliers, business partners and other individuals in our data centers and on our networks. Additionally, we use and are dependent upon information technology systems that utilize sophisticated operational systems and network infrastructure to run all facets of our generation, transmission and distribution services. The secure maintenance of information and information technology systems is critical to our operations. Despite security measures we have employed, including certain measures implemented pursuant to mandatory NERC Critical Infrastructure Protection standards, our infrastructure may be increasingly vulnerable to attacks by hackers or terrorists as a result of the rise in the sophistication and volume of cyber attacks. Also, our information and information technology systems may be breached due to viruses, human error, malfeasance or other malfunctions and disruptions. Any such attack or breach could: (i) compromise our generation, transmission and distribution services, development and construction of new facilities or capital improvement projects; (ii) adversely affect our customer operations; (iii) corrupt data; or (iv) result in unauthorized access to the information stored on our networks, including, company proprietary information, employee data, and personal customer data, causing the information to be publicly disclosed, lost or stolen or result in incidents that could result in harmful effects on the environment and human health, including loss of life. Any such attack, breach, access, disclosure or other loss of information could result in lost revenue, the inability to conduct critical business functions and serve customers, legal claims or proceedings, regulatory penalties, increased regulation, increased protection costs for enhanced cyber security systems or personnel, damage to our reputation and/or the rendering of our disclosure controls and procedures ineffective, all of which could adversely affect our business and financial condition.

Physical Acts of War, Terrorism or Other Attacks on any of Our Facilities or Other Infrastructure Could Have an Adverse Effect on Our Business, Results of Operations and Financial Condition

As a result of the continued threat of physical acts of war, terrorism, or other attacks in the United States, our electric generation, fuel storage, transmission and distribution facilities and other infrastructure, including nuclear and other power plants, transformer and high voltage lines and substations, or the facilities or other infrastructure of an interconnected company, could be direct targets of, or indirect casualties of, an act of war, terrorism, or a cyber or other attack, which could result in disruption of our ability to generate, purchase, transmit or distribute electricity, otherwise disrupt our customer operations and/or result in incidents that could result in harmful effects on the environment and human health, including loss of life. Any such disruption or incident could result in a significant decrease in revenue, significant additional capital and operating costs, including additional costs to implement additional security systems or personnel to purchase electricity and to replace or repair our assets over and above any available insurance reimbursement, higher insurance deductibles, higher premiums and more restrictive insurance policies, greater regulation with higher attendant costs, generally, and significant damage to our reputation, which could have an adverse effect on our business, results of operations and financial condition.

Capital Improvements and Construction Projects May Not be Completed Within Forecasted Budget, Schedule or Scope Parameters or Could be Canceled Which Could Adversely Affect Our Business and Results of Operations

Our business plan calls for extensive capital investments in electric generation, transmission and distribution, including but not limited to our *Energizing the Future* transmission expansion program. We may be exposed to the risk of substantial price increases in the costs of labor and materials used in construction, nonperformance of equipment and increased costs due to delays, including delays relating to the procurement of permits or approvals, adverse weather or environmental matters. We engage numerous contractors and enter into a large number of construction 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. Also, because we enter into construction agreements for the necessary materials and to obtain the required construction related services, any cancellation by FirstEnergy of a construction agreement could result in significant termination payments or penalties. Any delays, increased costs or losses or cancellation of a construction project could adversely affect our business and results of operations, particularly if we are not permitted to recover any such costs in rates.

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 unit costs than newer technologies such as fuel cells, microturbines, windmills and photovoltaic solar cells. It is possible that advances in technologies will reduce costs of new technology and/or changes in regulatory policy will create benefits that make these new technologies more competitive with central station electricity production. Such advances in technologies and/or changes in regulatory policy could decrease sales and revenues from our existing generation assets, and this could have a material adverse effect on our results of operations. To the extent that new generation technologies are connected directly to load, bypassing the transmission and distribution systems, potential impacts could include decreased transmission and distribution revenues, stranded assets and increased uncertainty in load forecasting and integrated resource planning.

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. Certain FirstEnergy companies also provide guarantees to third party creditors on behalf of other FirstEnergy affiliate companies under transactions of the type described above or under financing transactions. Any failure to perform under such a guarantee by such 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.

Certain FirstEnergy Companies Have Guaranteed the Performance of Third Parties, Which May Result in Substantial Costs in the Event of Non-Performance

Certain FirstEnergy companies have issued certain guarantees of the performance of others, which obligates such FirstEnergy companies to perform in the event that the third parties do not perform. FE is a guarantor under a syndicated three-year senior secured term loan facility due October 18, 2015, under which Global Holding borrowed $350 million in connection with the repayment of a prior term loan facility under which Signal Peak and Global Rail were borrowers. In the event of non-performance by the third parties, FirstEnergy could incur substantial cost to fulfill the obligations under such guarantees. Such performance guarantees could have a material adverse impact on our financial position and operating results.

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

To the Extent Our Policies to Control Costs Designed to Mitigate Low Energy, Capacity and Market Prices are Unsuccessful, We Could Experience a Negative Impact on Our Results of Operations and Financial Condition

The May 2013 PJM RPM auction for the 2016/2017 Delivery Year capacity produced prices in the region served by our competitive generation segment that were lower than expected, and the May 2014 PJM RPM auction for the 2017/2018 Delivery Year capacity reflected some, but still less than expected, improvement. These results may be a broader indication of an underlying supply/demand imbalance that continues to affect power producers in this region, adding pressure on already depressed energy prices and potentially pushing any significant power price recovery further into the future than we, or the industry at large, previously expected. Since 2012, as part of our ongoing comprehensive review of competitive operations related to, among other things, plant economics, we have deactivated more than 5,000 MW of competitive generation. To the extent our policies designed to control our costs, or other facets of our financial plan, are unsuccessful, we could experience a negative impact on our results of operations and financial condition. To address problems in the capacity market, PJM in December 2014 proposed significant market reforms, including its Capacity Performance proposal. To the extent PJM's Capacity Performance proposal does not work as intended, or to the extent that the proposed changes to the PJM Tariff are not accepted, energy and capacity market prices may remain volatile and low.

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 transmission and operating 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 FERC or by one or more of the state regulatory commissions in which our utility subsidiaries operate. Also, these rates may not be set to recover such 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 or 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. Further, there can be no assurance that we will retain the expected recovery in future rate cases.

In addition, as a U.S. corporation, we are subject to U.S. laws, Executive Orders, and regulations administered and enforced by the U.S. Department of Treasury and the Department of Justice restricting or prohibiting business dealings in or with certain nations and with certain specially designated nationals (individuals and legal entities). If any of our existing or future operations or investments, including our joint venture investment in Signal Peak or our continued procurement of uranium from existing suppliers, are subsequently determined to involve such prohibited parties we could be in violation of certain covenants in our financing documents and unless we cease or modify such dealings, we could also be in violation of such U.S. laws, Executive Orders and sanctions regulations, each of which could have a material adverse effect on our business, financial condition, results of operations and cash flows.

State Rate Regulation May Delay or Deny Full Recovery of Costs and Impose Risks on Our Operations. Any Denial of or Delay in, Cost Recovery Could Have an Adverse Effect on Our Business, Results of Operations, Cash Flows and Financial Condition.

Each of the Utilities' retail rates is set by its respective regulatory agency for utilities in the state 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 through traditional, cost-based regulated utility ratemaking. As a result, any of the Utilities may not be permitted to recover its costs and, even if it is able to do so, there may be a significant delay between the time it incurs such costs and the time it is allowed to recover them. Factors that may affect outcomes in the distribution rate cases include: (i) the value of plant in service; (ii) authorized rate of return; (iii) capital structure (including hypothetical capital structures); (iv) depreciation rates; (v) the allocation of shared costs, including consolidated deferred income taxes and income taxes payable across the FirstEnergy utilities; (vi) regulatory approval of rate recovery mechanisms for capital spending programs (including for example accelerated deployment of smart meters); and (vii) the accuracy of forecasts used for ratemaking purposes in "future test year" cases. FirstEnergy can provide no assurance that any base rate request filed by any of the Utilities, including the pending rate cases in New Jersey and Pennsylvania, and the pending ESP IV in Ohio discussed below will be granted in whole or in part. Any denial of, or delay in, any base rate request could restrict the applicable Utility from fully recovering its costs of service, may impose risks on its operations, and may negatively impact its results of operations and financial condition. In addition, to the extent that any of the Utilities seeks rate increases after an extended period of frozen or capped rates, pressure may be exerted on the applicable legislators and regulators to take steps to control rate increases, including through some form of rate increase moderation, reduction or freeze. Any related public discourse and debate can increase uncertainty associated with the regulatory process, the level of rates and revenues that are ultimately obtained, and the ability of the Utility to recover costs. Such uncertainty may restrict operational flexibility and resources, and reduce liquidity and increase financing costs.

Any Denial of, or Delay in, Cost Recovery Resulting from JCP&L's Pending Base Rate Case or in Association with the Generic Storm Proceeding Before the NJBPU May Impose Risks on our Operations and May Negatively Impact our Credit Rating, Results of Operations and Financial Condition

Our distribution rates in New Jersey are set by the NJBPU through traditional, cost-based regulated utility ratemaking. As a result, JCP&L may not be able to recover all of its increased, unexpected or necessary costs and, even if it is able to do so, there may be a significant delay between the time it incurs such costs and the time it is allowed to recover them.

We can provide no assurance that JCP&L's request to increase rates in its pending base rate case, or any future proceeding, will be granted in whole or in part, or when it will receive a decision on such requests from the NJBPU. Any denial of, or delay in, its request to increase rates in the pending base rate case or any continued delay in its request to recover costs associated with Hurricane Sandy and other 2011 or 2012 major storms could negatively impact our results of operations and financial condition. Any denial of, or delay in, the request to increase rates embodied in an Order from the NJBPU resulting from the base rate case could restrict it from fully recovering its costs of service, may impose risks on our operations, and may negatively impact our results of operations and financial condition. Also, the uncertainty regarding JCP&L's pending rate case and generic storm proceedings have already led to adverse credit rating agency action, and could lead to further adverse rating agency actions in the future.

Any Denial of, or Delay in, Cost Recovery Resulting from OE's, CEI's and TE's Pending ESP IV Before the PUCO May Impose Risks on our Operations and May Negatively Impact our Credit Rating, Results of Operations and Financial Condition

ESPs may be filed in Ohio as a means to establish the mechanism by which generation rates are set and may also include other provisions related to distribution and transmission service, all of which is subject to the approval of the PUCO. As a result, OE, CEI, and TE may not be authorized to implement all of the rates, riders, and mechanisms for which they are seeking approval, or there may be a delay in such authorization. OE, CEI, and TE filed their proposed ESP IV entitled *Powering Ohio's*

Progress on August 4, 2014, which included proposals to continue their Rider DCR mechanism, base distribution rate freeze, competitive bidding process for non-shopping load, and to undertake and implement an Economic Stability Program provision, which includes a 15-year purchase power agreement with FES for the output of Sammis, Davis-Besse and FES' share of OVEC, designed to provide customers retail rate stability against market prices over a longer term.

There can be no assurance that OE's, CEI's, and TE's request for approval of the ESP IV: *Powering Ohio's Progress* will be granted in whole or in part. OE, CEI, and TE expect to receive a decision on their ESP IV in the second quarter of 2015. Any denial of, or delay in, the approval of the ESP IV could negatively impact the results of operations and financial conditions of FE and FES.

Any Denial of, or Delay in, Cost Recovery Resulting from the Pennsylvania Companies' Pending Rate Cases Before the PPUC, May Impose Risks on our Operations and May Negatively Impact our Credit Rating, Results of Operations and Financial Condition

Our distribution rates in Pennsylvania are set by the PPUC through traditional, cost-based regulated utility ratemaking. As a result, the Pennsylvania Companies may not be able to recover all of their increased, unexpected or necessary costs and, even if they are able to do so, there may be a significant delay between the time they incur such costs and the time they are allowed to recover them.

There can be no assurance that the Pennsylvania Companies' Joint Petitions for Settlement, which settled all but one issue in the rate proceedings, will be approved by PPUC. Any denial of, or delay in, their request to increase rates in the pending base rate cases or to recover their costs could negatively impact the results of operations and financial condition of FE.

Federal Rate Regulation May Delay or Deny Full Recovery of Costs and Impose Risks on Our Operations. Any Denial of or Delay in Cost Recovery Could Have an Adverse Effect on Our Business, Results of Operations, Cash Flows and Financial Condition.

FERC policy currently permits recovery of prudently-incurred costs associated with wholesale power rates and the expansion and updating of transmission infrastructure within its jurisdiction. If FERC were to adopt a different policy regarding recovery of transmission costs or if transmission needs do not continue or develop as projected, our strategy of investing in transmission could be affected. If FERC were to lower the rate of return it has authorized for FirstEnergy's cost-based wholesale power rates or transmission investments and facilities, it could reduce future net income and cash flows and impact our financial condition.

On October 31, 2014, ATSI filed a proposal with FERC to change the structure of its formula rate. The proposed change requested to move from an "historical looking" approach, where transmission rates reflect actual costs for the prior year, to a "forward looking" approach, where transmission rates would be based on the estimated costs for the coming year, with an annual true up. FERC accepted the formula rate proposal effective January 1, 2015, but also set the rate for hearing and settlement proceedings subject to refund. Settlement discussions under a FERC-appointed settlement judge are ongoing. FERC also initiated an inquiry into ATSI's ROE and certain other matters, also subject to refund. A procedural schedule for the ROE hearing has not yet been established. There can be no assurance as to the outcome of these proceedings or the impact on ATSI's recovery mechanism and an adverse result could have an adverse impact on our results of operations and business conditions.

Regulatory Changes in the Electric Industry Could Affect Our Competitive Position and Result in Unrecoverable Costs Adversely Affecting Our Business and Results of Operations

As a result of regulatory 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 and competitive energy providers conduct their business. FERC and the U.S. Congress propose changes from time to time in the structure and conduct of the electric utility industry.

If any regulatory 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 regulatory efforts to modify our business or the industry.

The Business Operations of Our Regulated Transmission Segment and Certain Activities of Our CES Segment Are Subject to Regulation by FERC and Could be Adversely Affected by Such Regulation

FERC granted certain FirstEnergy generating subsidiaries authority to sell electric energy, capacity and ancillary services at market-based rates. These orders also granted waivers of certain FERC accounting, record-keeping and reporting requirements, as well as, for certain of these subsidiaries, waivers of the requirements to obtain FERC approval for issuances of securities. FERC's orders that grant this market-based rate authority reserve with FERC the right to revoke or revise that authority if FERC subsequently determines that these companies can exercise market power in transmission or generation, or create barriers to entry, or have engaged in prohibited affiliate transactions. In the event that one or more of FirstEnergy's market-based rate authorizations were to be revoked or adversely revised, the affected FirstEnergy subsidiary(ies) would be required to file with FERC for authorization of individual wholesale sales transactions, which could involve costly and possibly lengthy regulatory proceedings. In addition, such subsidiary(ies) would no longer enjoy the flexibility afforded by the waivers associated with the current market-based rate authorizations.

There Are Uncertainties Relating to Our Participation in RTOs

RTO rules could affect our ability to sell energy and capacity produced by our generating facilities to users in certain markets. The rules governing the various regional power markets may change from time to time, which could affect our costs or revenues. In some cases these changes are contrary to our interests and adverse to our financial returns. The prices in day-ahead and real-time energy markets and RTO capacity markets have been volatile and RTO rules may contribute to this volatility.

All of our generating assets currently participate in PJM, which conducts RPM auctions for capacity on an annual planning year basis. The prices our generating companies can charge for their capacity are determined by the results of the PJM auctions, which are impacted by the supply and demand of capacity resources and load within PJM and also may be impacted by transmission system constraints and PJM rules relating to bidding for DR, energy efficiency resources, and imports, among others. Auction prices could fluctuate substantially over relatively short periods of time. To the extent PJM's December 2014 Capacity Performance proposal does not work as intended or proposed changes to the PJM Tariff are not accepted, energy and capacity market prices may remain volatile and low. We cannot predict the outcome of future auctions, but if the auction prices are sustained at low levels, our results of operations, financial condition and cash flows could be adversely impacted.

We incur fees and costs to participate in RTOs. Administrative costs imposed by RTOs, including the cost of administering energy markets, may increase. To the degree we incur significant additional fees and increased costs to participate in an RTO, and are limited with respect to recovery of such costs from retail customers, our results of operations and cash flows could be significantly impacted.

We may be allocated a portion of the cost of transmission facilities built by others due to changes in RTO transmission rate design. We may be required to expand our transmission system according to decisions made by an RTO rather than our own internal planning processes. Various proposals and proceedings before FERC may cause transmission rates to change from time to time. In addition, RTOs have been developing rules associated with the allocation and methodology of assigning costs associated with improved transmission reliability, reduced transmission congestion and firm transmission rights that may have a financial impact on us.

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.

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 time frame 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 distribution 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 comprehensive review of FirstEnergy's coal-fired generating facilities in light of the MATS and other expanded environmental requirements, we deactivated twenty-one (21) older coal-fired generating units in 2012 and 2013, and as previously announced, we intend to deactivate five (5) additional older coal-fired generating units in 2015. 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. EPA has investigated 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. On December 21, 2011, the EPA finalized the MATS to establish emission standards for, among other things, mercury, PM and HCL, for electric generating units. The costs associated with MATS compliance, and other environmental laws, is substantial. MATS is also being challenged by numerous entities before the U.S. Supreme Court. Depending on the outcome of these legal proceedings and how MATS and other EPA 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.

Moreover, new environmental laws or regulations including, but not limited to EPA proposed GHG emission and water discharge regulations, or changes to existing environmental laws or regulations may materially increase our costs of compliance or accelerate the timing of capital expenditures. Because of the deregulation of certain of our generation facilities, 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 EPA has proposed regulations at the federal level to reduce GHG emissions (including CO_2) from electric generating facilities. Due to the uncertainty of control technologies available to reduce GHG emissions, any legal obligation that would require us to substantially reduce our GHG emissions could result in substantial additional costs, adversely affecting cash flow and profitability, and raise uncertainty about the future viability of fossil fuels, particularly coal, as an energy source for new and existing electric generation facilities.

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 and the federal, state and international initiatives seeking to reduce GHG emissions.

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.

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

The EPA has proposed regulatory changes, specifically, eight treatment options for waste water discharge from electric power plants, of which four are "preferred" by the agency. The preferred options range from more stringent chemical and biological treatment requirements to zero discharge requirements and the EPA is scheduled to finalize these regulatory changes in September 2015. The EPA has also 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, reducing impingement mortality (when aquatic organisms are pinned against screens or other parts of a cooling water intake system) to a 12% annual average and entrainment (which occurs when aquatic life is drawn into a facility's cooling water system) using site-specific controls based on studies to be submitted to permitting authorities. 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 implementation of impingement and entrainment performance standards by permitting authorities, 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 CCR Regulations Could Have an Adverse Impact on Our Results of Operations and Financial Condition

As an owner and operator of coal-fired generating units, we are subject to various federal and state solid, non-hazardous and hazardous waste regulations. On December 19, 2014, EPA finalized regulations for CCRs (non-hazardous waste), establishing national standards for the safe disposal of CCRs from electric generating plants. Depending on how the final rules are ultimately implemented, the future costs of compliance with such CCR regulations may require material capital expenditures. See Note 15, Commitments, Guarantees and Contingencies - Environmental Matters of the Combined Notes to the Consolidated Financial Statements.

We Are or May be Subject to Costs of Remediation of Environmental Contamination at Current or Formerly Owned Facilities

We may be 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. We are currently involved in a number of proceedings relating to sites where other hazardous substances have been deposited and we 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. Remediation activities associated with our former MGP operations are one source of such costs. 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.

Mandatory Renewable Portfolio Requirements Could Negatively Affect Our Costs

Where federal or state legislation mandates the use of renewable and alternative fuel sources, such as wind, solar, biomass and geothermal and such legislation does 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. Such mandatory renewable portfolio requirements 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.

Changes in Local, State or Federal Tax Laws Applicable To Us or Adverse Audit Results or Tax Rulings, and Any Resulting Increases in Taxes and Fees, May Adversely Affect Our Results of Operation, Financial Audit and Cash Flow

FirstEnergy is subject to various local, state and federal taxes, including income, franchise, real estate, sales and use and employment-related taxes. We exercise significant judgment in calculating such tax obligations, booking reserves as necessary to reflect potential adverse outcomes regarding tax positions we have taken and utilizing tax benefits, such as carryforwards and credits. Additionally, various tax rate and fee increases may be proposed or considered in connection with such changes in local, state or federal tax law. 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. Any such changes, or any adverse tax audit results or adverse tax rulings on positions taken by FirstEnergy or its subsidiaries could have a negative impact on its results of operations, financial condition and cash flows.

Risks Associated With Financing and Capital Structure

Volatility or Unfavorable Conditions in the Capital and Credit Markets May Adversely Affect Our Business, Including the Immediate 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. We also deposit cash in short-term investments. Volatility in the capital and credit markets could adversely affect our ability to draw on our credit facilities and cash. 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. 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.

Fluctuations 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. Unfavorable conditions 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 that 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 Counterparties Could Adversely Affect Us

We are exposed to the risk that counterparties that owe us money, power, fuel or other commodities could breach their obligations. 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, which would cause our financial results to be diminished and we might incur losses. Some of our agreements contain provisions that require the counterparties to provide credit support to secure all or part of their obligations to FirstEnergy or its subsidiaries. If the counterparties to these arrangements fail to perform, we may have a right to receive the proceeds from the credit support provided, however the credit support may not always be adequate to cover the related obligations. In such event, we may incur losses in addition to amounts, if any, already paid to the counterparties, including by being forced to enter into alternative arrangements at then-current market prices that may exceed our contractual prices. Although our estimates take into account the expected probability of default by a counterparty, our actual exposure to a default by customers or other counterparties may be greater than the estimates predict, which 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, including our ability to pay dividends and service debt, 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 and that the Recent Reduction in Our Dividend, or any Future Reductions Declared by our Board, Will Have a Positive Impact on Our Results of Operations

On January 21, 2014, in connection with actions taken to refocus our business strategy as a result of continuing weak economic conditions and depressed energy prices, our Board of Directors declared a revised quarterly dividend of $0.36 per share of outstanding common stock, which equates to an indicated annual dividend of $1.44 per share and is lower than the $0.55 per share per quarter ($2.20 per share annually) that FirstEnergy previously paid since 2008. Our Board of Directors will continue to regularly evaluate our common stock dividend and determine an appropriate dividend each quarter taking into account such factors as, 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. Additionally, we cannot assure common shareholders that the recent reduction, or any future reduction, in our dividend will be successful in strengthening our results of operations and liquidity.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

The first mortgage indentures for the Ohio Companies, Penn, MP, PE, WP, 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 Note 6, Leases and Note 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.

FirstEnergy controls the following generation sources as of January 31, 2015, 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	Competitive FES	Competitive AE Supply	Regulated
			Net Demonstrated Capacity (MW)		
Super-critical Coal-fired:					
Bruce Mansfield (Shippingport, PA)	1	830 [1]	830	—	—
Bruce Mansfield (Shippingport, PA)	2	830	830	—	—
Bruce Mansfield (Shippingport, PA)	3	830	830	—	—
Harrison (Haywood, WV)	1-3	1,984	—	—	1,984
Pleasants (Willow Island, WV)	1-2	1,300	—	1,300	—
W. H. Sammis (Stratton, OH)	6-7	1,200	1,200	—	—
Fort Martin (Maidsville, WV)	1-2	1,098	—	—	1,098
		8,072	3,690	1,300	3,082
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	—	—
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
		2,229	2,151	67	11
Nuclear:					
Beaver Valley (Shippingport, PA)	1	939	939	—	—
Beaver Valley (Shippingport, PA)	2	933 [4]	933	—	—
Davis-Besse (Oak Harbor, OH)	1	908	908	—	—
Perry (N. Perry Village, OH)	1	1,268 [5]	1,268	—	—
		4,048	4,048	—	—
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	—
Hunlock CT (Hunlock Creek, PA)	1	45	—	45	—

Buchanan (Oakwood, VA)	1-2	43 [6]	—	43	—
Other		156	156	—	—
		1,603	701	902	—
Pumped-storage Hydro:					
Bath County (Warm Springs, VA)	1-6	1,200 [7]	—	713	487
Yard's Creek (Blairstown Twp., NJ)	1-3	210 [8]	—	—	210
		1,410	—	713	697
Wind and Solar Power		496 [9]	496	—	—
Total		**17,858**	**11,086**	**2,982**	**3,790**

(1) Includes FE's leasehold interest of 93.83% (779 MW) from non-affiliates.
(2) Scheduled to be deactivated in 2015.
(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 2.60% (24 MW) from non-affiliates.
(5) Includes OE's leasehold interest of 3.75% (48 MW) from non-affiliates.
(6) Represents Buchanan Energy's 50% interest. 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 AGC's 40% interest in Bath County, a pumped-storage hydroelectric station. The station is operated by 60% owner Virginia Electric and Power Company. AGC is 59% owned by AE Supply and 41% owned by MP.
(8) Represents JCP&L's 50% ownership interest.
(9) 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 24,136 pole miles.

The Utilities' electric distribution systems include 267,880 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 154,635,024 kV-amperes.

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

FirstEnergy's distribution and transmission systems as of December 31, 2014, consist of the following:

	Distribution Lines[(1)]	Transmission Lines[(1)]	Substation Transformer Capacity[(2)]
			kV Amperes
OE	61,084	468	7,664,462
Penn	13,507	—	1,090,120
CEI	33,312	—	10,339,429
TE	18,980	77	2,973,973
JCP&L	23,150	2,579	22,234,086
ME	18,820	1,403	11,527,235
PN	27,382	2,870	16,372,087
ATSI[(4)]	—	7,500	28,862,400
WP	21,938	2,598	14,866,132
MP	25,464	2,113	15,372,834
PE	24,243	4,314	19,130,266
TrAIL[(3)]	—	214	4,202,000
Total	267,880	24,136	154,635,024

(1) Circuit 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 assets of 138 kV and greater located in the service territories of MP, PE and WP.
(4) Represents transmission line assets of 69 kV and greater located in the service territories of OE, Penn, CEI and TE.

ITEM 3. LEGAL PROCEEDINGS

Reference is made to Note 14, Regulatory Matters, and Note 15, Commitments, Guarantees and Contingencies of the Combined Notes to Consolidated Financial Statements for a description of certain legal proceedings involving FirstEnergy and FES.

ITEM 4. MINE SAFETY DISCLOSURES

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 is not disclosed because it is a wholly owned subsidiary of FirstEnergy and there is no market for its common stock.

Information regarding compensation plans for which shares of FirstEnergy common stock may be issued is incorporated herein by reference to FirstEnergy's 2015 proxy statement to be filed with the SEC pursuant to Regulation 14A under the Securities Exchange Act.

The table below includes information regarding purchases of FE common stock during the fourth quarter of 2014:

	Period			
	October	November	December	Fourth Quarter
Total Number of Shares Purchased[1]	2,592	—	33,301	35,893
Average Price Paid per Share	$ 33.51	—	$ 39.71	$ 39.26

[1] Share amounts reflect shares associated with Restricted Stock awards vesting during the quarter which were sold to cover tax obligations.

FirstEnergy does not currently have any publicly announced plan or program for share purchases.

ITEM 6. SELECTED FINANCIAL DATA

For the Years Ended December 31,	2014	2013	2012	2011	2010
	(In millions, except per share amounts)				
Revenues	$ 15,049	$ 14,892	$ 15,255	$ 16,087	$ 13,299
Income From Continuing Operations	$ 213	$ 375	$ 755	$ 856	$ 696
Earnings Available to FirstEnergy Corp.	$ 299	$ 392	$ 770	$ 885	$ 742
Earnings per Share of Common Stock:					
Basic - Continuing Operations	$ 0.51	$ 0.90	$ 1.81	$ 2.19	$ 2.37
Basic - Discontinued Operations (Note 19)	0.20	0.04	0.04	0.03	0.07
Basic - Earnings Available to FirstEnergy Corp.	$ 0.71	$ 0.94	$ 1.85	$ 2.22	$ 2.44
Diluted - Continuing Operations	$ 0.51	$ 0.90	$ 1.80	$ 2.18	$ 2.35
Diluted - Discontinued Operations (Note 19)	0.20	0.04	0.04	0.03	0.07
Diluted - Earnings Available to FirstEnergy Corp.	$ 0.71	$ 0.94	$ 1.84	$ 2.21	$ 2.42
Weighted Average Shares Outstanding:					
Basic	420	418	418	399	304
Diluted	421	419	419	401	305
Dividends Declared per Share of Common Stock	$ 1.44	$ 1.65	$ 2.20	$ 2.20	$ 2.20
Total Assets	$ 52,166	$ 50,424	$ 50,494	$ 47,410	$ 35,611
Capitalization as of December 31:					
Total Equity	$ 12,422	$ 12,695	$ 13,093	$ 13,299	$ 8,952
Long-Term Debt and Other Long-Term Obligations	19,176	15,831	15,179	15,716	12,579
Total Capitalization	$ 31,598	$ 28,526	$ 28,272	$ 29,015	$ 21,531

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.

	2014		2013	
	High	Low	High	Low
First Quarter	$ 34.28	$ 30.10	$ 42.50	$ 38.26
Second Quarter	$ 35.59	$ 31.17	$ 46.77	$ 35.72
Third Quarter	$ 34.95	$ 29.98	$ 39.88	$ 35.46
Fourth Quarter	$ 40.84	$ 33.04	$ 38.92	$ 31.29

Yearly	$	40.84	$	29.98	$	46.77	$	31.29

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

SHAREHOLDER RETURN

The following graph shows the total cumulative return from a $100 investment on December 31, 2009 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 96,265 and 96,090 holders of 421,102,570 and 421,182,123 shares of FirstEnergy's common stock as of December 31, 2014 and January 31, 2015, 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.

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," "forecast," "will," "intend," "believe," "project," "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, which may include the following:

- The speed and nature of increased competition in the electric utility industry, in general, and the retail sales market in particular.
- The ability to experience growth in the Regulated Distribution and Regulated Transmission segments and to successfully implement our revised sales strategy for the CES segment.
- The accomplishment of our regulatory and operational goals in connection with our transmission investment plan, pending transmission and distribution rate cases and the effectiveness of our repositioning strategy to reflect a more regulated business profile.
- Changes in assumptions regarding economic conditions within our territories, assessment of the reliability of our transmission system, or the availability of capital or other resources supporting identified transmission investment opportunities.
- The impact of the regulatory process on the pending matters at the federal level and in the various states in which we do business including, but not limited to, matters related to rates and pending rate cases, including the ESP IV in Ohio.
- The impact of the federal regulatory process on FERC-regulated entities and transactions, in particular FERC regulation of wholesale energy and capacity markets, including PJM markets and FERC-jurisdictional wholesale transactions; FERC regulation of cost-of-service rates, including FERC Opinion No. 531's revised ROE methodology for FERC-jurisdictional wholesale generation and transmission utility service; and FERC's compliance and enforcement activity, including compliance and enforcement activity related to NERC's mandatory reliability standards.
- 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 such as a polar vortex or other significant weather events, and all associated regulatory events or actions.
- Regulatory outcomes associated with storm restoration costs, including but not limited to, Hurricane Sandy, Hurricane Irene and the October snowstorm of 2011.
- Changing energy, capacity and commodity market prices including, but not limited to, coal, natural gas and oil, and their availability and impact on retail margins.
- The continued ability of our regulated utilities to recover their costs.
- Costs being higher than anticipated and the success of our policies to control costs and to mitigate low energy, capacity and market prices.
- Other legislative and regulatory changes, and revised environmental requirements, including, but not limited to, proposed GHG emission and water discharge regulations and the effects of the EPA's CCR regulations, CSAPR, MATS, including our estimated costs of compliance, and CWA 316(b) water intake regulation.
- 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 regulated and competitive fossil units, including the impact on vendor commitments, and the timing thereof as they relate to the reliability of the transmission grid.
- The impact of other future changes to the operational status or availability of our generating units.
- Adverse regulatory or legal decisions and outcomes with respect to our nuclear operations (including, but not limited to the revocation or non-renewal of necessary licenses, approvals or operating permits by the NRC or as a result of the incident at Japan's Fukushima Daiichi Nuclear Plant).
- Issues arising from the indications of cracking in the shield building at Davis-Besse.
- The risks and uncertainties associated with litigation, arbitration, mediation and like proceedings, including, but not limited to, any such proceedings related to vendor commitments.
- The impact of labor disruptions by our unionized workforce.
- Replacement power costs being higher than anticipated or not fully 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 continue to reduce costs and to successfully execute our financial plans designed to improve our credit

metrics and strengthen our balance sheet through, among other actions, our previously-implemented dividend reduction and our other proposed capital raising initiatives.

- 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.

- Changing market conditions that could affect the measurement of certain liabilities and the value of assets held in our NDTs, pension trusts and other trust funds, and cause us and/or 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 announced financial 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/or 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/or our major industrial and commercial customers, and other counterparties with which we do business, including fuel suppliers.
- The impact of any changes in tax laws or regulations or adverse tax audit results or rulings.
- Issues concerning the stability of domestic and foreign financial institutions and counterparties with which we do business.
- The risks associated with cyber-attacks on our electronic data centers that could compromise the information stored on our networks, including proprietary information and customer data.
- 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 period may in the aggregate vary from prior periods 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.

FIRSTENERGY CORP.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF
FINANCIAL CONDITION AND RESULTS OF OPERATIONS

FIRSTENERGY'S BUSINESS

FirstEnergy's reportable segments are as follows: Regulated Distribution, Regulated Transmission, and CES.

The Regulated Distribution segment distributes electricity through FirstEnergy's ten utility operating companies, serving approximately six 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, SSO and default service requirements in Ohio, Pennsylvania, New Jersey and Maryland. This segment also includes regulated electric generation facilities located primarily in West Virginia, Virginia and New Jersey that MP and JCP&L, respectively, own or contractually control. The segment's results reflect the commodity costs of securing electric generation and the deferral and amortization of certain fuel costs. This business segment currently controls approximately 3,790 MWs of generation capacity.

The service areas of, and customers served by, FirstEnergy's regulated distribution utilities are summarized below (in thousands):

Company	Area Served	Customers Served [1]
OE	Central and Northeastern Ohio	1,036
Penn	Western Pennsylvania	162
CEI	Northeastern Ohio	745
TE	Northwestern Ohio	308
JCP&L	Northern, Western and East Central New Jersey	1,103
ME	Eastern Pennsylvania	558
PN	Western Pennsylvania	588
WP	Southwest, South Central and Northern Pennsylvania	721
MP	Northern, Central and Southeastern West Virginia	390
PE	Western Maryland and Eastern West Virginia	397
		6,008

[1] As of December 31, 2014

The Regulated Transmission segment transmits electricity through transmission facilities owned and operated by ATSI, TrAIL, and certain of FirstEnergy's utilities (JCP&L, ME, PN, MP, PE and WP), and the regulatory asset associated with the abandoned PATH project. 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 project regulatory asset, these revenues are primarily from transmission services provided pursuant to the PJM Tariff to LSEs. The segment's results also reflect the net transmission expenses related to the delivery of electricity on FirstEnergy's transmission facilities.

The CES segment, through FES and AE Supply, primarily 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 currently controls approximately 14,068 MWs of capacity, including 885 MWs of capacity scheduled to be deactivated by April 2015. The segment's net income is primarily derived from electric generation sales less the related costs of electricity generation, including fuel, purchased power and net transmission (including congestion) and ancillary and capacity costs charged by PJM to deliver energy to the segment's customers.

The CES segment derives its revenues from the sale of generation to direct, governmental aggregation, POLR, structured 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 DR 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.

Corporate/Other contains corporate support and other businesses that are below the quantifiable threshold for separate disclosure as a reportable segment and interest expense on stand-alone holding company debt and corporate income taxes. Additionally, reconciling adjustments for the elimination of inter-segment transactions are included in Corporate/Other. As of December 31, 2014, Corporate/Other had $4.2 billion of stand-alone holding company long-term debt, of which 28% was subject to variable-interest rates, and $1.7 billion was borrowed by FE under its revolving credit facility.

EXECUTIVE SUMMARY

In 2014, FirstEnergy launched programs to begin reinvesting in its Regulated Transmission and Regulated Distribution segments. This investment strategy is focused on delivering enhanced customer service and reliability, strengthening grid and cyber-security, and adding resiliency and operating flexibility to its transmission and distribution infrastructure.

Focusing on reinvestment in its regulated operations will also provide stability and growth for FirstEnergy as this plan is implemented over the coming years.

This pivotal year featured the launch of FirstEnergy's transmission investment program, economic growth in the territory served by FirstEnergy's Regulated Distribution segment, active rate plans at ten utility operating companies, and an adjusted competitive strategy designed to reduce risk while preserving value in that business.

The centerpiece of FirstEnergy's regulated investment strategy is the *Energizing the Future* transmission expansion plan, which was introduced in late 2013. The initial phase of this plan includes $4.2 billion in investments through 2017 to modernize the transmission system owned by FirstEnergy's Regulated Transmission segment. In 2014, $1.4 billion was invested across more than 1,100 projects to improve the durability and flexibility of this transmission system.

The transmission investment program is also designed to prepare the electrical system for load growth, including increased demand related to continued development in the Marcellus and Utica shale regions of the utilities' western Pennsylvania, eastern Ohio and West Virginia service areas. While FirstEnergy continues to monitor recent developments in shale related activity, in 2014, more than 400 MWs of new industrial demand associated with shale gas activity came online in FirstEnergy's region, and more than 1,100 MWs of additional planned expansion is expected at customer facilities through 2019. Five consecutive years of growth in the industrial customer class is another strong indicator of the region's positive economic future.

FirstEnergy also pursued regulatory initiatives across its utility footprint in 2014, focused on providing significant benefits to customers while ensuring the timely and appropriate recovery of investments. These initiatives include:

- A rate case application in West Virginia, filed in April 2014, and a settlement agreement approved by the WVPSC on February 3, 2015, that will result in recovery of $63 million annually for reliability investments, storm damage expenses, and investments in operating improvements and environmental compliance at MP's and PE's regulated, coal-fired power plants in the state.
- Rate case applications in Pennsylvania filed in August 2014, with a current settlement agreement in place that, if approved by the PPUC, would result in an increase in current distribution revenues of approximately $293 million, annually, across ME, PN, Penn and WP.
- The Ohio Companies' ESP IV, *Powering Ohio's Progress,* filed in August 2014, with an expected decision in the second quarter of 2015 that would freeze base distribution rates for three years while ensuring continued availability of more than 3,200 MWs, if approved by the PUCO, of FirstEnergy's critical baseload generating assets primarily located in the state and serving the long-term energy needs of Ohio customers.
- ATSI's October 2014 rate filing with FERC to request transmission rates using a "forward looking" approach, where transmission rates would be based on estimated costs for the current year with an annual true up. On December 31, 2014, FERC issued an order accepting ATSI's rate filing to become effective January 1, 2015, as requested, subject to refund and the outcome of hearing and settlement proceedings and FERC's inquiry into ATSI's ROE.

Additionally, JCP&L continues with its base rate proceeding in New Jersey as well as the NJBPU's ongoing generic storm proceeding. In March 2014, New Jersey regulators approved the recovery of $736 million in costs incurred to restore service following devastating storms in 2011 and 2012, and the company awaits final resolution of its base rate case, while continuing to advocate for a decision that supports continued investments in service reliability. In January 2015, the ALJ issued a recommended decision that, if approved by the NJBPU, would reduce annual revenues $107.5 million without considering any adjustment for 2012 storm costs or CTA.

In 2014, FirstEnergy set a new course for CES designed to limit risk in the current difficult energy market, while positioning the business to take advantage of future market upside.

Extreme weather events, including record low temperatures in January 2014, resulted in increased electricity demand and revealed weaknesses in the region's power supply. The situation underscored the implications of a growing dependence on less-reliable generating resources, DR and intermittent renewables. The volatility also raised concerns about whether the current capacity market can provide the right incentives to maintain adequate generating resources to meet demand in the PJM Region, especially in extreme conditions. In response to this crisis, FirstEnergy began repositioning its competitive business to focus on reducing exposure to weather-sensitive load in certain sales channels, and pursuing high-margin sales while leaving a portion of its generation available to capture future market opportunities. This strategy is designed to better position CES to benefit from opportunities as markets improve while limiting risk from continued challenging market conditions. At the same time, FirstEnergy continues to advocate for reforms that can ensure competitive energy markets adequately value baseload generation, which is essential to maintaining grid reliability.

The CES 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, 2014, committed contract sales for calendar year 2015, 2016 and 2017 are approximately 63 million MWHs, 36 million MWHs and 20 million MWHs, respectively. On average, CES expects to produce approximately 75 - 80 million MWHs of electricity annually, with an additional 5 million MWHs related to purchased power agreements for wind, solar and its entitlement to OVEC.

FirstEnergy has also reduced the size and shifted the mix of its generating assets, while reducing operating expenses and capital expenditures, including the deactivation of certain plants and the 2014 sale of certain hydro assets for approximately $394 million in February 2014. As a result, the remaining competitive fleet is more cost-effective, efficient and environmentally sound. FirstEnergy is on track to exceed benchmarks established by MATS and other environmental regulations. Several new opportunities to lower costs were identified in 2014, and FirstEnergy's total cost for MATS compliance is expected to be approximately $370 million ($178 million at CES and $192 million at Regulated Distribution), of which $133 million has been spent through 2014 ($56 million at CES and $77 million at Regulated Distribution).

In other generation matters, the replacement of two steam generators was successfully completed during a refueling outage at the Davis-Besse Nuclear Power Station during the spring of 2014. At the Beaver Valley Nuclear Power Station, the company deferred from 2017 to 2020 a planned Unit 2 reactor head and steam generator replacement after determining the unit can operate safely and reliably until that time. Additionally, at the Bruce Mansfield Power Station, while the plant continues to operate, if market reforms prove unsatisfactory and market conditions remain unfavorable, FirstEnergy may continue to minimize certain capital expenditures at the plant, including a delay of the new water treatment upgrades necessary for the continued operation of the plant after the LBR CCR Impoundment closes on December 31, 2016.

FirstEnergy's net income in 2014 was $299 million, or basic earnings of $0.71 per share of common stock ($0.71 diluted), compared with $392 million, or $0.94 per share of common stock ($0.94 diluted) in 2013, and $771 million, or $1.85 per share of common stock ($1.84 diluted) in 2012.

				Increase (Decrease)	
	2014	2013	2012	2014 vs 2013	2013 vs 2012
Basic earnings per share:					
Continuing operations	$ 0.51	$ 0.90	$ 1.81	$ (0.39)	$ (0.91)
Discontinued operations	0.20	0.04	0.04	0.16	—
Earnings per basic share	$ 0.71	$ 0.94	$ 1.85	$ (0.23)	$ (0.91)
Diluted earnings per share:					
Continuing operations	$ 0.51	$ 0.90	$ 1.80	$ (0.39)	$ (0.90)
Discontinued operations	0.20	0.04	0.04	0.16	—
Earnings per diluted share	$ 0.71	$ 0.94	$ 1.84	$ (0.23)	$ (0.90)

In 2014, FirstEnergy's revenues increased $157 million as compared to 2013. The increase is primarily attributable to a $331 million increase in wholesale generation sales at Regulated Distribution resulting from the October 2013 Harrison/Pleasants asset transfer whereby MP acquired 1,476 MWs of generation from AE Supply. Additionally, Regulated Transmission's revenues increased $38 million, or 5%, year over year resulting from incremental cost of service and rate base recovery. Partially offsetting these increases was a decrease in CES revenues of approximately $209 million. As discussed above, in 2014 CES began to reduce its exposure to weather sensitive load and eliminate load obligations that do not adequately cover risk premiums. This change in strategy resulted in a 9% decrease in MWH sales compared to 2013. Going forward, CES expects to target 65 to 75 million MWHs in contract sales with a projected target portfolio mix of approximately 10 to 15 million MWHs in Governmental Aggregation sales, 0 to 10 million MWHs of POLR sales, 0 to 20 million MWHs in large commercial and industrial sales (Direct),10 to 20 million MWHs in block wholesale sales, including Structured sales, and 10 to 20 million MWHs of spot wholesale sales. The target portfolio mix of contract sales and wholesale sales is consistent with CES' expected annual generation of 80-85 million MWHs.

Operating expenses increased $677 million in 2014 as compared to 2013. This increase includes a $1.1 billion increase in FirstEnergy's Pension and OPEB mark-to-market adjustment partially offset by the absence of impairment charges on regulatory assets and long lived assets of $1.1 billion recognized in 2013. FirstEnergy immediately recognizes in the fourth quarter of each year (or when a plan is determined to qualify for re-measurement) the change in fair value of plan assets and net actuarial gains and losses. Given the decline in the current interest rate environment and its impact on discount rates and revisions to mortality assumptions extending the expected life in key demographics, FirstEnergy's Pension and OPEB mark-to-market adjustment was $835 million in 2014 versus a credit of $256 million in 2013. The 2013 impairment charges resulted from CES's deactivation of the Hatfield and Mitchell generating units and Regulated Distribution's impairment resulting from the Harrison/Pleasants asset transfer reducing the net book value of the Harrison plant to the amount permitted to be included in rate base.

Other changes in operating expenses include the following:

- Lower fuel expense of $216 million, primarily reflected the deactivation of power plants in 2013 and increased outages. Fuel expense at CES and Regulated Distribution was further impacted by the October 2013 Harrison/Pleasants asset transfer.
- Purchased power increased $753 million, primarily reflecting higher CES purchases resulting from plant deactivations, increased outages and the asset transfer discussed above as well as higher unit pricing and capacity expense. The increase in unit pricing primarily resulted from the extreme weather events in the first quarter of 2014, which included the polar vortex. These weather events significantly increased the demand for electricity and natural gas throughout the PJM Region resulting in average prices for electricity nearly double the three-year average at $68 per MWH.
- Other operating expenses increased $369 million primarily resulting from higher costs at Regulated Distribution associated with transmission expenses, which are deferred for future recovery with no material impact on earnings, increased vegetation management expenses in West Virginia, which are also deferred for future recovery, as well as higher operating and maintenance costs of $98 million associated with distribution maintenance activities, storm restoration costs and the Harrison/Pleasants asset transfer. Although CES other operating expenses were higher year over year, the increase was primarily attributable to higher transmission costs, which resulted from the extreme market conditions in the first quarter of 2014, and higher mark-to-market expenses on derivative contracts, partially offset by lower generation operating and maintenance costs primarily resulting from the deactivation of generating plants and the Harrison/Pleasants asset transfer.

FirstEnergy's other expenses decreased $121 million year over year, primarily resulting from the absence of a loss on debt redemptions of $124 million recognized in 2013. Higher interest expense was offset by higher investment income and capitalized financing costs, which is primarily attributable to Regulated Transmission's *Energizing the Future* investment plan.

FirstEnergy's effective tax rate on income from continuing operations was (24.6%) in 2014 compared to 34.2% in 2013. The decrease in the effective tax rate was attributable to several tax planning initiatives executed during 2014, including tax benefits associated with a change in accounting method with the IRS for costs associated with the refurbishment of meters and transformers and the expiration of the statute of limitations on uncertain state tax positions. Additionally, during 2014, FirstEnergy recognized tax benefits of $25 million that related to prior periods resulting from adjustments to its tax basis balance sheet.

Finally, in February 2014, CES sold certain hydro generating assets for $394 million and recorded an after-tax gain of approximately $78 million included in discontinued operations.

STRATEGY AND OUTLOOK

FirstEnergy owns a large and diverse mix of assets managed in an integrated model, featuring an electric distribution service area and transmission footprint that are among the largest in the nation, as well as a significant competitive generation fleet and competitive sales business. As the initiatives launched to develop the transmission business, strengthen the regulated utilities, and manage overall risk within the competitive business are implemented, 2015 is expected be a transformational year for FirstEnergy.

Regulated Transmission

FirstEnergy's strategy is focused on investments in its regulated operations. The centerpiece of this strategy is the $4.2 billion *Energizing the Future* investment plan. This program is focused on a large number of small projects within the existing 24,000 mile service territory that improve service to customers. The projects within the program are either regulatory required or support reliability enhancement. Regulatory required projects include those requested by PJM to support grid reliability, generator deactivations, or shale gas expansion activities. The second category of projects, those that support reliability enhancement, focus on replacing aging equipment; increasing automation, communication, and security within the system; and increasing load serving capability. In the initial years of the program, the majority of the projects are located within the ATSI system, with expectations to move east across FirstEnergy's service territory over time. FirstEnergy currently expects to fund these investments through a combination of debt and previously announced equity issuances through its stock investment plan, to the extent available, employee benefit plans, and cash. In 2015, FirstEnergy expects Regulated Transmission capital expenditures of $970 million for regulatory required and reliability enhancement projects. In total, FirstEnergy has identified approximately $15 billion in transmission investment opportunities across its system beyond the 2014-2017 period, making this a continuing and sustainable platform for investment. In the future, FirstEnergy may consider additional equity to fund these capital investments in the Regulated Transmission business.

Regulated Distribution

In the five-state service territory served by FirstEnergy's Regulated Distribution segment, the economy has begun to recover from the recession. While residential sales have been relatively flat, commercial and industrial sales have grown consistently over the past year. The location of the Marcellus and Utica shale gas region has provided a source of this growth and distribution sales in 2015 are forecasted to increase 1% over 2014 to approximately 151 million MWHs and industrial sales through 2019 are forecasted to increase by approximately 15% from 2013 levels, about half of which are driven by shale related projects. Additionally, FirstEnergy expects to resolve all of its remaining pending rate case applications during the first half of 2015.

CES

FirstEnergy continues to focus on maintaining the value of its competitive business given continued challenging conditions within the PJM market. The business is projected to be self-sustaining over the next several years, with positive cash-flow over the 2015-2018 period. While it cannot predict if or when a power price recovery may occur, FirstEnergy believes it has taken appropriate action over the last several years to reposition this business for such a recovery. CES expects to sell its output through a combination of retail and wholesale sales, while maintaining 10-20 million MWHs for spot wholesale sales in order to optimize risk management and market upside opportunities.

In addition to the strategy of growing the Regulated Transmission and Regulated Distribution segments and repositioning the CES segment, FirstEnergy is also focused on improving the balance sheet over time consistent with its business profile, maintaining investment grade metrics at each business unit, and maintaining strong liquidity for an overall stable financial position.

The following represents a high level summary of assumptions and drivers that management expects will impact 2015 results of operations:

- Increased CES capacity revenue resulting from higher capacity rates as well as decreased transmission expenses resulting from lower retail sales volumes.
- Increased Regulated Transmission revenues resulting from a higher rate base and a forward-looking rate structure at ATSI.
- Increased Regulated Distribution revenues from projected sales of approximately 151 million MWHs in 2015 versus 149.5 million MWHs in 2014 and expected base rate increases considering outcomes in the Pennsylvania and New Jersey utilities assuming the final orders in the rate cases are consistent with settlement agreements or current expectations.
- Increased regulatory asset amortization for storm costs incurred by JCP&L in 2011 and 2012.
- Increased depreciation and property taxes as a result of a higher rate base for the Regulated Distribution and Regulated Transmission businesses.
- Increased operation and maintenance expenses resulting from higher Regulated Distribution expenses and three planned nuclear outages in 2015 verses two in 2014.
- Increased net financing costs related to certain 2014 financing activities including new debt issuances at the Regulated Distribution and Regulated Transmission businesses and the refinancing of pollution control bonds at CES.
- Increased pension/OPEB expense primarily impacting the Regulated Distribution and CES segments due to lower amortization of prior service credits and updated actuarial assumptions as of December 31, 2014.
- An effective corporate income tax rate of 37% to 38% in 2015.

RESULTS OF OPERATIONS

The financial results discussed below include revenues and expenses from transactions among FirstEnergy's business segments. A reconciliation of segment financial results is provided in Note 18. Segment Information, of the Combined Notes to Consolidated Financial Statements. Certain prior year amounts have been reclassified to conform to the current year presentation. Net income by business segment was as follows:

				Increase (Decrease)	
	2014	2013	2012	2014 vs 2013	2013 vs 2012
	(In millions, except per share amounts)				
Net Income (Loss) By Business Segment:					
Regulated Distribution	$ 465	$ 501	$ 540	$ (36)	$ (39)
Regulated Transmission	223	214	226	9	(12)
Competitive Energy Services	(337)	(220)	215	(117)	(435)
Corporate/Other [1]	(52)	(103)	(210)	51	107
Net Income	$ 299	$ 392	$ 771	$ (93)	$ (379)
Basic Earnings Per Share:					
Continuing operations	$ 0.51	$ 0.90	$ 1.81	$ (0.39)	$ (0.91)
Discontinued operations (Note 19)	0.20	0.04	0.04	0.16	—

Earnings per basic share	$ 0.71	$ 0.94	$ 1.85	$ (0.23)	$ (0.91)
Diluted Earnings Per Share:					
Continuing operations	$ 0.51	$ 0.90	$ 1.80	$ (0.39)	$ (0.90)
Discontinued operations (Note 19)	0.20	0.04	0.04	0.16	—
Earnings per diluted share	$ 0.71	$ 0.94	$ 1.84	$ (0.23)	$ (0.90)

(1) Consists primarily of interest on stand-alone holding company debt, none-core business related activity and corporate income taxes.

Summary of Results of Operations — 2014 Compared with 2013

Financial results for FirstEnergy's business segments in 2014 and 2013 were as follows:

2014 Financial Results	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Corporate/Other and Reconciling Adjustments	FirstEnergy Consolidated
			(In millions)		
Revenues:					
External					
Electric	$ 8,898	$ 769	$ 5,281	$ (193)	$ 14,755
Other	204	—	189	(99)	294
Internal	—	—	819	(819)	—
Total Revenues	9,102	769	6,289	(1,111)	15,049
Operating Expenses:					
Fuel	567	—	1,713	—	2,280
Purchased power	3,385	—	2,150	(819)	4,716
Other operating expenses	2,081	139	2,075	(333)	3,962
Pension and OPEB mark-to-market	506	2	327	—	835
Provision for depreciation	658	127	387	48	1,220
Amortization of regulatory assets, net	1	11	—	—	12
General taxes	693	70	171	28	962
Total Operating Expenses	7,891	349	6,823	(1,076)	13,987
Operating Income (Loss)	1,211	420	(534)	(35)	1,062
Other Income (Expense):					
Loss on debt redemptions	—	—	(8)	—	(8)
Investment income	56	—	45	(29)	72
Interest expense	(589)	(131)	(189)	(164)	(1,073)
Capitalized financing costs	14	55	37	12	118
Total Other Expense	(519)	(76)	(115)	(181)	(891)
Income (Loss) From Continuing Operations Before Income Taxes (Benefits)	692	344	(649)	(216)	171
Income taxes (benefits)	227	121	(226)	(164)	(42)
Income (Loss) From Continuing Operations	465	223	(423)	(52)	213
Discontinued Operations, net of tax	—	—	86	—	86
Net Income (Loss)	$ 465	$ 223	$ (337)	$ (52)	$ 299

2013 Financial Results	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Corporate/Other and Reconciling Adjustments	FirstEnergy Consolidated
			(In millions)		
Revenues:					
External					
Electric	$ 8,499	$ 731	$ 5,542	$ (161)	$ 14,611
Other	221	—	186	(126)	281
Internal	—	—	770	(770)	—
Total Revenues	8,720	731	6,498	(1,057)	14,892
Operating Expenses:					
Fuel	377	—	2,119	—	2,496
Purchased power	3,308	—	1,425	(770)	3,963
Other operating expenses	1,773	131	2,007	(318)	3,593
Pension and OPEB mark-to-market	(149)	—	(107)	—	(256)
Provision for depreciation	606	114	439	43	1,202
Amortization of regulatory assets, net	529	10	—	—	539
General taxes	697	54	202	25	978
Impairment of long-lived assets	322	—	473	—	795
Total Operating Expenses	7,463	309	6,558	(1,020)	13,310
Operating Income (Loss)	1,257	422	(60)	(37)	1,582
Other Income (Expense):					
Gain (Loss) on debt redemptions	—	—	(149)	17	(132)
Investment income	57	—	11	(35)	33
Interest expense	(543)	(93)	(222)	(158)	(1,016)
Capitalized financing costs	31	14	42	16	103
Total Other Expense	(455)	(79)	(318)	(160)	(1,012)
Income (Loss) From Continuing Operations Before Income Taxes (Benefits)	802	343	(378)	(197)	570
Income taxes (benefits)	301	129	(141)	(94)	195
Income (Loss) From Continuing Operations	501	214	(237)	(103)	375
Discontinued Operations, net of tax	—	—	17	—	17
Net Income (Loss)	$ 501	$ 214	$ (220)	$ (103)	$ 392

Changes Between 2014 and 2013 Financial Results Increase (Decrease)	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Corporate/Other and Reconciling Adjustments	FirstEnergy Consolidated
			(In millions)		
Revenues:					
External					
Electric	$ 399	$ 38	$ (261)	$ (32)	$ 144
Other	(17)	—	3	27	13
Internal	—	—	49	(49)	—
Total Revenues	382	38	(209)	(54)	157
Operating Expenses:					
Fuel	190	—	(406)	—	(216)
Purchased power	77	—	725	(49)	753
Other operating expenses	308	8	68	(15)	369
Pension and OPEB mark-to-market	655	2	434	—	1,091
Provision for depreciation	52	13	(52)	5	18
Amortization of regulatory assets, net	(528)	1	—	—	(527)
General taxes	(4)	16	(31)	3	(16)
Impairment of long-lived assets	(322)	—	(473)	—	(795)
Total Operating Expenses	428	40	265	(56)	677
Operating Income (Loss)	(46)	(2)	(474)	2	(520)
Other Income (Expense):					
Loss on debt redemptions	—	—	141	(17)	124
Investment income	(1)	—	34	6	39
Interest expense	(46)	(38)	33	(6)	(57)
Capitalized financing costs	(17)	41	(5)	(4)	15
Total Other Expense	(64)	3	203	(21)	121
Income (Loss) From Continuing Operations Before Income Taxes (Benefits)	(110)	1	(271)	(19)	(399)
Income taxes (benefits)	(74)	(8)	(85)	(70)	(237)
Income (Loss) From Continuing Operations	(36)	9	(186)	51	(162)
Discontinued Operations, net of tax	—	—	69	—	69
Net Income (Loss)	$ (36)	$ 9	$ (117)	$ 51	$ (93)

Regulated Distribution — 2014 Compared with 2013

Regulated Distribution's net income decreased $36 million in 2014 compared to 2013. Regulated Distribution's Pension and OPEB mark-to-market adjustment increased $655 million which was partially offset by a reduction in regulatory asset impairment charges of $305 million and an impairment on long-lived assets of $322 million incurred in 2013. Excluding the impact of these charges, year over year earnings were impacted by higher distribution operating and maintenance costs, including the impact of higher benefit costs, higher depreciation and property taxes, and higher interest expense from debt issuances. These items were partially offset by slightly higher distribution deliveries, higher earnings associated with the October 2013 Harrison/Pleasants asset transfer, and a lower effective tax rate.

Revenues —

The $382 million increase in total revenues resulted from the following sources:

Revenues by Type of Service	For the Years Ended December 31, 2014	2013	Increase (Decrease)
		(In millions)	
Distribution services	$ 3,694	$ 3,762	$ (68)
Generation sales:			
Retail	4,043	3,959	84
Wholesale	661	330	331
Total generation sales	4,704	4,289	415
Transmission	500	448	52
Other	204	221	(17)
Total Revenues	$ 9,102	$ 8,720	$ 382

The decrease in distribution services revenue is primarily related to a decrease in revenues from the ME and PN NUG riders as a result of the expiration of certain NUG contracts in 2013 and a rider rate decrease associated with the recovery of energy efficiency and other customer program costs for the Pennsylvania Companies. This was partially offset by higher electric distribution MWH deliveries of 1.1% as described below, rate increases for the Ohio Companies associated with energy efficiency performance shared savings and the DCR, and higher revenues for the Pennsylvania Companies associated with the recovery of Smart Meter program costs. Certain Ohio energy efficiency programs permit the Ohio Companies to bill and collect shared savings revenues if energy efficiency programs meet or exceed the state mandates. Additionally, the DCR provides for cost of service and rate base recovery associated with incremental distribution plant investments in Ohio. Distribution deliveries by customer class are summarized in the following table:

Electric Distribution MWH Deliveries	For the Years Ended December 31, 2014	2013	Increase
		(In thousands)	
Residential	54,766	54,479	0.5%
Commercial	42,988	42,582	1.0%
Industrial	51,213	50,243	1.9%
Other	586	584	0.3%
Total Electric Distribution MWH Deliveries	149,553	147,888	1.1%

Higher deliveries to residential customers primarily reflect increased weather-related usage resulting from heating degree days that were 7% above 2013, and 9% above normal, partially offset by cooling degree days that were 15% below 2013, and 12% below normal. Increased deliveries to commercial customers reflect improving economic conditions across FirstEnergy's service territories. In the industrial sector, increased sales to steel, automotive and shale gas customers were partially offset by lower sales to chemical and paper customers. Distribution deliveries in 2015 are expected to increase to approximately 151 million MWHs primarily reflecting an increase in the industrial sector resulting from shale gas related activity and remain flat in both the commercial and residential sectors as compared to 2014 levels.

The following table summarizes the price and volume factors contributing to the $415 million increase in generation revenues in 2014 compared to 2013:

Source of Change in Generation Revenues	Increase
	(In millions)
Retail:	
Effect of increase in sales volumes	$ 14
Change in prices	70
	84
Wholesale:	
Effect of increase in sales volumes	166
Change in prices	79
Capacity revenue	86
	331
Increase in Generation Revenues	$ 415

The increase in retail generation sales volume was primarily due to weather-related usage, as described above, and improving economic conditions, partially offset by increased customer shopping in Pennsylvania. The increase in retail generation prices reflects higher Pennsylvania PTC prices, the completion of marginal transmission loss refunds to ME and PN customers in the second quarter of 2013 and a higher generation rate at WP, which includes the recovery of transmission costs effective June 2013. Additionally, the impact on retail generation prices of MP's Temporary Transaction Surcharge (TTS) associated with the October 2013 Harrison/Pleasants asset transfer was offset by a rate reduction associated with the recovery of deferred energy costs. As part of the TTS, MP earns a return on and of the Harrison plant costs.

The increase in wholesale generation revenues of $331 million in 2014 resulted from increased volume and energy prices associated with market conditions related to extreme weather events in January 2014 and increased capacity revenue related to the October 2013 Harrison/Pleasants asset transfer whereby MP acquired from AE Supply 1,476 MWs of net capacity. During January 2014, unprecedented customer demand associated with prolonged periods of bitterly cold temperatures and unit unavailability across the PJM footprint resulted in severe market price volatility for electricity and natural gas throughout PJM. Eight of the ten highest winter demands for electricity on the PJM system occurred in January 2014. The difference between wholesale generation revenues, primarily associated with MP's regulated generation, and certain energy costs are deferred for future recovery, with no material impact to earnings.

The increase in transmission revenues of $52 million reflects higher PJM revenues at MP associated with market conditions related to extreme weather events described above and an increase in the Ohio Companies' NMB transmission rider revenues, partially offset by the termination of WP's network transmission rider effective June 2013 as discussed above. Network transmission costs are now recovered through WP's generation rate.

Other revenues decreased $17 million primarily due to less customer requested work in 2014 compared to 2013.

Operating Expenses —

Total operating expenses increased $428 million primarily due to the following:

- Fuel expense was $190 million higher in 2014 primarily related to increased generation as a result of the October 2013 Harrison/Pleasants asset transfer.

- Purchased power costs were $77 million higher in 2014 primarily due to increased unit prices and capacity expense reflecting higher auction clearing prices, partially offset by a decrease in purchased volumes required.

Source of Change in Purchased Power		Increase (Decrease)
		(In millions)
Purchases from non-affiliates:		
Change due to increased unit costs	$	127
Change due to decreased volumes		(134)
		(7)
Purchases from affiliates:		
Change due to increased unit costs		39
Change due to increased volumes		2
		41
Capacity expense		58
Increase in costs deferred		(15)
Increase in Purchased Power Costs	$	77

- Other operating expenses increased $308 million primarily due to:

  - Higher transmission expenses of $130 million primarily due to PJM transmission costs associated with higher congestion rates at MP as a result of market conditions related to extreme weather events in January 2014 and higher PJM transmission costs resulting from the October 2013 Harrison/Pleasants asset transfer. The differences between current transmission revenues and transmission costs incurred are deferred for future recovery, resulting in no material impact on current period earnings.

  - Higher distribution operating and maintenance expenses of $75 million resulting from higher maintenance activities and storm related restoration expenses, including $26 million of storm expenses deferred for future recovery.

  - Higher vegetation management expenses in West Virginia of $33 million, which were deferred for future recovery per authorization of the WVPSC.

  - Higher retirement benefit costs of $33 million primarily reflecting higher net periodic benefit costs before the pension and OPEB mark-to-market adjustments discussed below.

  - Increased regulated generation operating and maintenance expenses of $23 million, reflecting increased costs associated with the October 2013 Harrison/Pleasant asset transfer and a planned outage at Fort Martin.

- Pension and OPEB mark-to-market adjustments increased $655 million, primarily reflecting a lower discount rate and revisions to mortality assumptions extending the expected life in key demographics used to measure related obligations in 2014.

- Depreciation expense increased $52 million due to a higher asset base, including $22 million at MP associated with the October 2013 Harrison/Pleasants asset transfer.

- Net regulatory asset amortization decreased $528 million primarily due to:

  - Impairment charges on regulatory assets of $305 million associated with the recovery of marginal transmission losses at ME and PN ($254 million) and the recovery of RECs for the Ohio Companies ($51 million) that occurred in 2013,
  - Decreased energy efficiency amortization reflecting a rate decrease associated with certain programs for the Pennsylvania Companies ($67 million),
  - Lower default generation service and NUG cost recovery in Pennsylvania ($48 million),
  - Increased deferral of West Virginia vegetation management expenses ($33 million) and customer refunds associated with the gain on the Pleasants plant resulting from the October 2013 Harrison/Pleasants asset transfer ($36 million), and

- Higher storm cost deferrals ($26 million).

- General taxes decreased $4 million primarily due to lower revenue-related taxes, partially offset by higher property taxes and an increase in the West Virginia business and occupation tax as a result of the October 2013 Harrison/Pleasants asset transfer.

- The 2013 impairment of long-lived assets of $322 million reflects MP's charge to reduce the net book value of the Harrison plant to the amount permitted to be included in rate base as part of the October 2013 Harrison/Pleasants asset transfer.

Other Expense —

Other expense increased $64 million in 2014 primarily due to higher interest expense at MP resulting from new debt issuances of $580 million associated with the financing of the October 2013 Harrison/Pleasants asset transfer, a new debt issuance of $500 million in August 2013 at JCP&L and lower capitalized financing costs related primarily to a decrease in the rate used for borrowed funds.

Income Taxes —

Regulated Distribution's effective tax rate was 32.8% and 37.5% for 2014 and 2013, respectively. The decrease in the effective tax rate primarily resulted from changes in state apportionment factors, an increase in state flow through income tax benefits and other realized tax benefits. In 2015, the Regulated Distribution segment anticipates an effective tax rate of approximately 37% to 38%.

Regulated Transmission — 2014 Compared with 2013

Net income increased $9 million in 2014 compared to 2013. Higher Transmission revenues and capitalized financing costs associated with Regulated Transmission's *Energizing the Future* investment plan were partially offset by higher operating costs and interest expense.

Revenues —

Total revenues increased $38 million principally due to higher revenue requirements at ATSI and TrAIL, reflecting incremental cost of service and rate base recovery resulting from their annual rate filings effective June 2013 and June 2014.

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

Revenues by Transmission Asset Owner	For the Years Ended December 31, 2014	2013	Increase (Decrease)
		(In millions)	
ATSI	$ 242	$ 209	$ 33
TrAIL	214	207	7
PATH	13	20	(7)
Utilities	300	295	5
Total Revenues	$ 769	$ 731	$ 38

Operating Expenses —

Total operating expenses increased $40 million principally due to higher property taxes, depreciation and other operating expenses.

Other Expenses —

Total other expenses decreased $3 million principally due to higher capitalized financing costs of $41 million related to increased construction work in progress balances associated with the *Energizing the Future* investment plan, partially offset by increased interest expense resulting from new debt issuances of $1.0 billion at FET and $400 million at ATSI.

Income Taxes —

Regulated Transmission's effective tax rate was 35.2% and 37.6% for 2014 and 2013, respectively. The decrease in the effective tax rate primarily resulted from an increase in AFUDC equity flow through. In 2015, the Regulated Transmission segment anticipates an effective tax rate of approximately 37% to 38%.

CES — 2014 Compared with 2013

Operating results decreased $117 million in 2014 compared to 2013. Lower impairment charges of $473 million associated with the deactivation of the Hatfield and Mitchell generating units and lower losses on debt redemptions of $141 million were partially offset with higher Pension and OPEB mark-to-market adjustments of $434 million. Excluding the impact of these changes, year over year earnings were impacted by lower sales volumes, reflecting CES' change in selling efforts discussed below and an increase in costs incurred to serve contract sales due to extreme market conditions in January 2014. Partially offsetting these items were lower operating expenses due to lower retail-related costs, lower generation costs resulting from plant deactivations and asset transfers, and higher capacity revenues from higher auction prices. Additionally, operating results were impacted by a $78 million after-tax gain on the sale of certain hydro facilities in February 2014.

Revenues —

Total revenues decreased $209 million in 2014, compared to 2013, primarily due to decreased sales volumes in the Direct and Governmental Aggregation sales channels, partially offset by higher volume in the Structured Sales channel. Revenues were also impacted by higher unit prices as a result of increased channel pricing and ancillary pass through revenues associated with PJM expenses incurred in January 2014 as well as higher capacity revenues, as described below.

The decrease in total revenues resulted from the following sources:

Revenues by Type of Service	For the Years Ended December 31, 2014	2013	Increase (Decrease)
		(In millions)	
Contract Sales:			
Direct	$ 2,359	$ 2,913	$ (554)
Governmental Aggregation	1,184	1,185	(1)
Mass Market	452	448	4
POLR	902	858	44
Structured Sales	522	421	101
Total Contract Sales	5,419	5,825	(406)
Wholesale	461	343	118
Transmission	220	144	76
Other	189	186	3
Total Revenues	$ 6,289	$ 6,498	$ (209)

MWH Sales by Channel	For the Years Ended December 31, 2014	2013	Increase (Decrease)
	(In thousands)		
Contract Sales:			
Direct	44,012	56,145	(21.6)%
Governmental Aggregation	19,569	20,859	(6.2)%
Mass Market	6,773	6,761	0.2 %
POLR	15,708	15,758	(0.3)%
Structured Sales	12,814	9,047	41.6 %
Total Contract Sales	98,876	108,570	(8.9)%
Wholesale	680	1,250	(45.6)%
Total MWH Sales	99,556	109,820	(9.3)%

As discussed above, in 2014, CES began to reduce its exposure to weather-sensitive loads and eliminate load obligations that do not adequately cover risk premiums. As part of this, CES eliminated future selling efforts in certain sales channels, such as Mass Market, medium commercial-industrial and select large commercial-industrial (Direct), to focus on a selective mix of retail sales channels, wholesale sales that hedge generation more effectively, and maintain a small open position to take advantage of market upside opportunities resulting from volatility similar to that experienced in the first quarter of 2014 as further discussed below. Support for current customers in the channels to be exited will remain through their respective contract terms.

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

	Source of Change in Revenues Increase (Decrease)				
MWH Sales Channel:	**Sales Volumes**	**Prices**	**Gain on Settled Contracts**	**Capacity Revenue**	**Total**
			(In millions)		
Direct	$ (629)	$ 75	$ —	$ —	$ (554)
Governmental Aggregation	(73)	72	—	—	(1)
Mass Market	1	3	—	—	4
POLR	(3)	47	—	—	44
Structured Sales	176	(75)	—	—	101
Wholesale	(17)	—	(21)	156	118

The Direct, Governmental Aggregation and Mass Market customer base was 2.1 million as of December 31, 2014, compared to 2.7 million as of December 31, 2013, reflecting the segment's efforts to reposition its sales portfolio to more effectively hedge its generation as discussed above. Additionally, although unit pricing was higher year over year in the Direct, Governmental Aggregation and Mass Market channels noted above, the increase was primarily attributable to higher capacity expense as discussed below, which is a component of the retail price. The increase associated with capacity was partially offset by lower energy pricing built into the retail product at the time customers were acquired for 2014 sales. Beginning in the fourth quarter of 2011, when there was a significant decline in energy prices, CES' 2014 retail sales position was approximately 30% committed, whereas its 2013 retail sales position was approximately 60% committed, resulting in a greater proportion of 2014 sales and unit prices being impacted by the decline in the energy prices. Additionally, higher Direct unit prices were impacted by approximately $33 million of ancillary pass through revenues associated with PJM expenses incurred in January 2014.

During January 2014, given higher customer usage associated with extreme weather conditions and unit unavailability, including the Beaver Valley Unit 1 outage, CES (including FES) was required to purchase higher volumes of power. These extreme weather events, which included the polar vortex, caused an increase in the demand for electricity and natural gas throughout the PJM Region. Average prices during first quarter 2014 were nearly $68 per MWH, or double the three-year average of about $34 per MWH. Furthermore, prices during the 10 highest-price, most volatile days in the first quarter where the average round-the-clock day-ahead price at AD Hub was between $100 and $500 per MWH and more specifically on January 7, 2014, when real-time prices exceeded $1,800 per MWH significantly impacted the results. Increased customer demand that was unhedged and replacement power requirements due to the timing of unplanned outages and derates contributed to purchasing additional volumes at these higher prices. Furthermore, in order to maintain system reliability, PJM incurred higher ancillary service costs, such as synchronous and operating reserves, throughout these extreme conditions. Approximately $800 million in ancillary service charges for the month of January 2014 were billed to all LSEs serving customers throughout the PJM Region based on load served, including FES. Certain of these costs are considered a "pass-through" event under existing contracts and were billed to commercial and industrial customers in 2014.

The increase in POLR revenues of $44 million was due to higher rates associated with the capacity expense component of the rate discussed above, partially offset by lower sales volumes. The increase in Structured Sales revenues of $101 million was due to higher sales volumes, partially offset by lower unit prices primarily due to market conditions related to extreme weather events in January 2014 that reduced the gains on various structured financial sales contracts.

Wholesale revenues increased $118 million primarily due to an increase in capacity revenue from higher capacity prices, partially offset by a decrease in short-term (net hourly positions) transactions. The decrease in Wholesale sales volumes was due to lower generation available to sell primarily as a result of the Harrison/Pleasants asset transfer and the deactivation of certain power plants in 2013. Capacity revenue is expected to increase in 2015 due to the results of the 2015/2016 PJM BRA, and decrease in the years shortly thereafter. The following tables summarize the PJM BRA capacity clearing prices by planning year and BRA capacity revenue by calendar year, excluding the impact, if any, of future incremental auctions or other future capacity transactions.

Planning Year - June 1 through May 31

$/MWD	2013 - 2014	2014 - 2015	2015 - 2016	2016 - 2017	2017 - 2018
RTO	$28	$126	$136	$59	$120

MAAC	$226	$136	$167	$119	$120
ATSI	$28	$126	$357	$114	$120

CES PJM BRA Capacity Revenue by Zone ($ Millions)

	2014	2015	2016	2017
ATSI	$180	$645	$480	$175
RTO	$150	$235	$145	$145
MAAC	$5	$5	$5	$5
EMAAC	$5	$5	$5	$5
CES *	$340	$890	$635	$330

** Revenue associated with FES is approximately $245, $743, $545, and $245 in 2014 - 2017, respectively. Additionally CES (and FES) have available capacity that can be offered into future incremental auctions of 2,765 MW and 2,455 MW for the 2016/2017 and 2017/2018 PJM planning years, respectively.*

Transmission revenue increased $76 million due to higher congestion revenue driven by market conditions related to extreme weather events in the first quarter 2014, as discussed above.

Other revenue increased $3 million in 2014 as compared to 2013 as higher lease revenues from additional repurchased equity interests in affiliated sale and leasebacks since 2013 was partially offset by a $17 million pre-tax gain recognized in 2013 on the sale of property to a regulated affiliate. CES earns lease revenue associated with the equity interests it has purchased.

Operating Expenses —

Total operating expenses increased $265 million in 2014 due to the following:

- Fuel costs decreased $406 million primarily due to lower generation volumes resulting from the October 2013 Harrison/Pleasants asset transfer, the deactivation of certain power plants in 2013 and increased outages as compared to the same period of 2013. Higher unit prices, primarily driven by increased peaking generation, was partially offset by the suspension of the DOE nuclear disposal fee, which was effective May 2014. Additionally, fuel costs were impacted by an increase in settlement and termination costs related to coal and transportation contracts. Terminations and settlements associated with damages on coal and transportation contracts were approximately $166 million and $128 million in 2014 and 2013, respectively. Excluding the impact of termination and settlement costs, if any, which cannot be estimated, unit prices are expected to decrease in 2015 as a result of lower expected peaking generation and a full-year benefit of the suspended DOE spent nuclear fuel fee.

- Purchased power costs increased $725 million due to higher volumes ($252 million), increased unit prices ($565 million) and higher capacity expenses ($311 million), partially offset by lower losses on financially settled contracts ($403 million). Higher purchased volumes were primarily due to lower available generation due to outages, the October 2013 Harrison/Pleasants asset transfer and the deactivation of certain power plants in 2013, partially offset by lower contract sales as described above. The increase in unit prices was primarily a result of market conditions related to extreme weather events in January 2014, partially offset by lower losses on financially settled contracts. The increase in capacity expense, which is a component of the segment 's retail price, was primarily the result of higher capacity rates associated with the segment's retail sales obligations. Due to the change in CES' selling efforts resulting in lower expected MWH sales, purchased power volumes are expected to decrease in future periods. However, while lower MWH sales in 2015 will reduce capacity expense, higher capacity prices will result in higher capacity expense in 2015.

- Fossil operating costs decreased $73 million primarily due to lower contractor, labor and materials and equipment costs resulting from previously deactivated units and the October 2013 Harrison/Pleasants asset transfer. Fossil operating expenses are expected to decrease primarily as a result of the scheduled deactivation of certain units by April 2015.

- Nuclear operating costs increased $6 million as a result of higher labor, contractor, materials and equipment costs. There were two refueling outages in each of 2014 and 2013, however, the duration of the outages in 2014 exceeded the prior year. Nuclear operating costs are expected to increase in 2015 as a result of three planned refueling outages.

- Transmission expenses increased $80 million primarily due to higher operating reserve and market-based ancillary costs associated with market conditions related to extreme weather events in January 2014, of which a portion were passed through to commercial and industrial customers, as discussed above. Additionally, effective June 1, 2013, network expenses associated with POLR sales in Pennsylvania became the responsibility of suppliers. Transmission expenses are expected to continue to decrease as a result of the change in selling efforts discussed above.

- General taxes decreased $31 million primarily due to lower gross receipts taxes resulting from reduced retail sales volumes, lower payroll taxes as a result of lower labor costs noted above, lower property taxes due to the October 2013 Harrison/Pleasants asset transfer, and reduced Ohio personal property taxes.
- Impairments of long-lived assets decreased $473 million due to the impairment of two unregulated, coal-fired generating plants in the second quarter of 2013. The units were deactivated in October of 2013.

- Depreciation expense decreased $52 million primarily due to a reduction in the asset base as a result of the plant deactivations and the October 2013 Harrison/Pleasants asset transfer noted above. Although depreciation expense decreased in 2014, it is expected to increase in future periods as a result of higher capital expenditures for projects such as MATS compliance and the Davis-Besse steam generator replacement completed in mid-2014.
- Pension and OPEB mark-to-market adjustments increased $434 million primarily reflecting a lower discount rate and revisions to mortality assumptions extending the expected life in key demographics used to measure related obligations in 2014.
- Other operating expenses increased $55 million primarily due to an increase in mark-to-market expenses on commodity contract positions, and an impairment of deferred advertising costs of $23 million associated with the elimination of future selling efforts in the Mass Market and certain Direct sales channels, partially offset by lower retail and marketing related costs. Retail and marketing related costs are expected to continue to decrease as a result of the change in selling efforts, as discussed above.

Other Expense —

Total other expense in 2014 decreased $203 million compared to 2013 due to the absence of a $141 million loss on debt redemptions in connection with senior notes that were repurchased in 2013, higher investment income primarily on the NDT investments, lower OTTI and lower net interest expense of $28 million due to debt redemptions.

Income Tax Benefits —

CES' effective tax rate was 34.8% and 37.3% for 2014 and 2013, respectively. The decrease in the effective tax rate, which resulted in a lower tax benefit on pre-tax losses, primarily resulted from changes in state apportionment factors and higher valuation allowances on certain NOL carryforwards. In 2015, CES anticipates an effective tax rate of approximately 37% to 38%.

Discontinued Operations —

Discontinued operations increased $69 million in 2014 compared to the same period of last year primarily due to a pre-tax gain of approximately $142 million ($78 million after-tax) associated with the sale of hydro assets in February 2014.

Corporate/Other — 2014 Compared with 2013

Financial results from Corporate/Other resulted in a $51 million increase in net income in 2014 compared to 2013 primarily due to higher tax benefits, partially offset by $17 million of gains on debt redemptions in 2013. The higher tax benefits primarily resulted from an IRS approved change in accounting method that increased the tax basis of certain assets resulting in higher future tax deductions, and the resolution of state tax benefits resulting from the expiration of the statute of limitation on certain state tax positions. Additional income tax benefits of $24.5 million were recognized in 2014 that relate to prior periods. The out-of-period adjustment primarily related to the correction of amounts included on FirstEnergy's tax basis balance sheet. Management has determined that these adjustments are not material to the current or any prior period. The 2013 effective tax rate benefited from reductions to valuation allowances against state NOL carryforwards, as well as changes in state apportionment factors, which reduced deferred tax liabilities. FirstEnergy anticipates a tax rate of approximately 36% to 37% in 2015.

Summary of Results of Operations — 2013 Compared with 2012

Financial results for FirstEnergy's business segments in 2013 and 2012 were as follows:

2013 Financial Results	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Corporate/Other and Reconciling Adjustments	FirstEnergy Consolidated
			(In millions)		
Revenues:					
External					
Electric	$ 8,499	$ 731	$ 5,542	$ (161)	$ 14,611
Other	221	—	186	(126)	281
Internal	—	—	770	(770)	—
Total Revenues	8,720	731	6,498	(1,057)	14,892
Operating Expenses:					
Fuel	377	—	2,119	—	2,496
Purchased power	3,308	—	1,425	(770)	3,963
Other operating expenses	1,773	131	2,007	(318)	3,593
Pension and OPEB mark-to-market	(149)	—	(107)	—	(256)
Provision for depreciation	606	114	439	43	1,202
Amortization of regulatory assets, net	529	10	—	—	539
General taxes	697	54	202	25	978
Impairment of long-lived assets	322	—	473	—	795
Total Operating Expenses	7,463	309	6,558	(1,020)	13,310
Operating Income (loss)	1,257	422	(60)	(37)	1,582
Other Income (Expense):					
Gain (Loss) on debt redemptions	—	—	(149)	17	(132)
Investment income	57	—	11	(35)	33
Interest expense	(543)	(93)	(222)	(158)	(1,016)
Capitalized interest	31	14	42	16	103
Total Other Expense	(455)	(79)	(318)	(160)	(1,012)
Income (Loss) From Continuing Operations Before Income Taxes (Benefits)	802	343	(378)	(197)	570
Income taxes (benefits)	301	129	(141)	(94)	195
Income (Loss) From Continuing Operations	501	214	(237)	(103)	375
Discontinued Operations, net of tax	—	—	17	—	17
Net Income (Loss)	501	214	(220)	(103)	392
Income attributable to noncontrolling interest	—	—	—	—	—
Earnings (Losses) Available to FirstEnergy Corp.	$ 501	$ 214	$ (220)	$ (103)	$ 392

2012 Financial Results	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Corporate/Other and Reconciling Adjustments	FirstEnergy Consolidated
			(In millions)		
Revenues:					
External					
Electric	$ 8,849	$ 735	$ 5,632	$ (214)	$ 15,002
Other	198	—	146	(93)	251
Internal	—	—	866	(864)	2
Total Revenues	9,047	735	6,644	(1,171)	15,255
Operating Expenses:					
Fuel	263	—	2,208	—	2,471
Purchased power	3,801	—	1,307	(862)	4,246
Other operating expenses	2,126	136	1,840	(342)	3,760
Pension and OPEB mark-to-market	392	2	215	—	609
Provision for depreciation	558	114	409	38	1,119
Amortization of regulatory assets, net	(65)	(3)	—	—	(68)
General taxes	706	44	209	25	984
Total Operating Expenses	7,781	293	6,188	(1,141)	13,121
Operating Income	1,266	442	456	(30)	2,134
Other Income (Expense):					
Investment income	84	1	66	(74)	77
Interest expense	(540)	(92)	(284)	(85)	(1,001)
Capitalized interest	25	8	44	13	90
Total Other Expense	(431)	(83)	(174)	(146)	(834)
Income From Continuing Operations Before Income Taxes	835	359	282	(176)	1,300
Income taxes	295	133	83	34	545
Income From Continuing Operations	540	226	199	(210)	755
Discontinued Operations, net of tax	—	—	16	—	16
Net Income	540	226	215	(210)	771
Income attributable to noncontrolling interest	—	—	—	1	1
Earnings Available to FirstEnergy Corp.	$ 540	$ 226	$ 215	$ (211)	$ 770

Changes Between 2013 and 2012 Financial Results Increase (Decrease)	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Corporate/Other and Reconciling Adjustments	FirstEnergy Consolidated
			(In millions)		
Revenues:					
External					
Electric	$ (350)	$ (4)	$ (90)	$ 53	$ (391)
Other	23	—	40	(33)	30
Internal	—	—	(96)	94	(2)
Total Revenues	(327)	(4)	(146)	114	(363)
Operating Expenses:					
Fuel	114	—	(89)	—	25
Purchased power	(493)	—	118	92	(283)
Other operating expenses	(353)	(5)	167	24	(167)
Pension and OPEB mark-to-market	(541)	(2)	(322)	—	(865)
Provision for depreciation	48	—	30	5	83
Deferral of storm costs	—	—	—	—	—
Amortization of regulatory assets, net	594	13	—	—	607
General taxes	(9)	10	(7)	—	(6)
Impairment of long-lived assets	322	—	473	—	795
Total Operating Expenses	(318)	16	370	121	189
Operating Income (Loss)	(9)	(20)	(516)	(7)	(552)
Other Income (Expense):					
Gain (Loss) on debt redemptions	—	—	(149)	17	(132)
Investment income	(27)	(1)	(55)	39	(44)
Interest expense	(3)	(1)	62	(73)	(15)
Capitalized interest	6	6	(2)	3	13
Total Other Expense	(24)	4	(144)	(14)	(178)
Income (Loss) From Continuing Operations Before Income Taxes (Benefits)	(33)	(16)	(660)	(21)	(730)
Income taxes (benefits)	6	(4)	(224)	(128)	(350)
Income (Loss) From Continuing Operations	(39)	(12)	(436)	107	(380)
Discontinued Operations, net of tax	—	—	1	—	1
Net Income (Loss)	(39)	(12)	(435)	107	(379)
Income attributable to noncontrolling interest	—	—	—	(1)	(1)
Earnings (Losses) Available to FirstEnergy Corp.	$ (39)	$ (12)	$ (435)	$ 108	$ (378)

Regulated Distribution — 2013 Compared with 2012

Net income decreased $39 million in 2013 compared to 2012. In 2013, the Regulated Distribution segment recognized an impairment charge of $322 million related to the October 2013 Harrison/Pleasants asset transfer and impairment charges of $305 million on regulatory assets associated with the recovery of marginal transmission losses for ME and PN and the recovery of RECs for the Ohio Companies. These charges were partially offset by a lower Pension and OPEB mark-to-market adjustment of $541 million in 2013 as compared to 2012. Excluding these charges, year over year earnings were impacted by higher depreciation and property taxes partially offset by distribution revenues associated with the Ohio Companies' DCR and higher distribution deliveries.

Revenues —

The $327 million decrease in total revenues resulted from the following sources:

Revenues by Type of Service	For the Years Ended December 31, 2013	2012	Increase (Decrease)
	(In millions)		
Distribution services	$ 3,762	$ 3,948	$ (186)
Generation sales:			
Retail	3,959	4,104	(145)
Wholesale	330	347	(17)
Total generation sales	4,289	4,451	(162)
Transmission	448	450	(2)
Other	221	198	23
Total Revenues	$ 8,720	$ 9,047	$ (327)

The decrease in distribution services revenue is primarily the result of a NJBPU-approved reduction to the JCP&L NUG Rider which was effective March 1, 2012 and a decrease to the ME and PN NUG riders resulting from the expiration of certain NUG contracts in 2012 and 2013. Additionally, lower recovery of energy efficiency expenses reflecting reduced costs was partially offset by an increase in the Ohio Companies' DCR rider and slightly higher distribution deliveries. Distribution deliveries increased by 0.9% in 2013 compared to 2012. Distribution deliveries by customer class are summarized in the following table:

Electric Distribution MWH Deliveries	Year Ended December 31 2013	2012	Increase (Decrease)
	(In thousands)		
Residential	54,479	53,993	0.9 %
Commercial	42,582	42,645	(0.1)%
Industrial	50,243	49,378	1.8 %
Other	584	585	(0.2)%
Total Electric Distribution MWH Deliveries	$ 147,888	$ 146,601	0.9 %

Higher deliveries to residential customers primarily reflects increased weather-related usage resulting from heating degree days that were 18% above 2012, and 2% above normal, partially offset by cooling degree days that were 15% below 2012, and 3% above normal. Lower deliveries to the commercial sector primarily reflect increasing energy efficiency mandates and DR initiatives. In the industrial sector, increased sales to steel, chemical, and shale gas customers were partially offset by lower sales to automotive and paper customers. Additionally, FirstEnergy expects additional growth in the industrial sector beyond 2013 for potential shale gas projects. As the gas fields are developed, the opportunity for additional manufacturing expansion could further support growth.

The following table summarizes the price and volume factors contributing to the $162 million decrease in generation revenues in 2013 compared to 2012:

Source of Change in Generation Revenues	Increase (Decrease)
	(In millions)
Retail:	
Effect of decrease in sales volumes	$ (194)
Change in prices	49
	(145)
Wholesale:	
Effect of decrease in sales volumes	(95)
Change in prices	78
	(17)
Decrease in Generation Revenues	$ (162)

The decrease in retail generation sales volume was primarily due to increased customer shopping in the Utilities' service territories during 2013, compared to 2012. This increased customer shopping, which does not impact earnings for the Regulated Distribution segment, is expected to continue. Total generation provided by alternative suppliers as a percentage of total MWH deliveries increased to 81% from 79% for the Ohio Companies, 66% from 64% for the Pennsylvania Companies, 47% from 46% for PE and 52% from 50% for JCP&L. The increase in prices reflects the completion of marginal transmission loss refunds to ME and PN customers in the second quarter of 2013 and a higher generation rate at WP, which includes the recovery of transmission costs beginning in June 2013.

The decrease in wholesale generation revenues of $17 million in 2013 resulted from the expiration of NUG contracts, partially offset by higher energy and capacity prices in 2013.

Other revenues increased by $23 million primarily due to more customer requested work for OE and JCP&L in 2013 compared to 2012.

Operating Expenses —

Total operating expenses decreased by $318 million primarily due to the following:

- Fuel expense was $114 million higher in 2013 primarily related to increased generation at Fort Martin as a result of planned and forced outages in 2012 and the asset transfer between MP and AE Supply of the Harrison Power Station effective October 9, 2013.
- Purchased power costs were $493 million lower in 2013 primarily due to a decrease in volumes required as a result of increased customer shopping, higher generation, reduced NUG purchases and lower unit power supply costs.

Source of Change in Purchased Power	Increase (Decrease)
	(In millions)
Purchases from non-affiliates:	
Change due to decreased unit costs	$ (68)
Change due to decreased volumes	(429)
	(497)
Purchases from affiliates:	
Change due to decreased unit costs	(10)
Change due to decreased volumes	(92)
	(102)
Decrease in costs deferred	106
Decrease in Purchased Power Costs	$ (493)

Other operating expenses decreased $353 million primarily due to:

- decreased energy efficiency program expenses of $40 million resulting from the completion of certain initiatives in Ohio and Pennsylvania, which are recoverable through rates;
- lower distribution operating and maintenance expenses of $363 million due to lower storm related maintenance activities during 2013 compared to 2012. Maintenance costs in 2012 related to Hurricane Sandy and the "derecho" wind storm totaled $386 million, of which $370 million was deferred for future recovery;
- higher transmission expenses of $50 million primarily due to PJM transmission costs associated with RMR units.

- Pension and OPEB mark-to-market charges decreased $541 million, reflecting a higher discount rate to measure related obligations in 2013.
- Depreciation expense increased by $48 million due to a higher asset base.
- Net regulatory asset amortization increased $594 million primarily due to the absence of deferred storm restoration expenses associated with Hurricane Sandy and the "derecho" wind storm ($370 million), regulatory asset charges associated with the recovery of marginal transmission losses at ME and PN ($254 million), recovery of RECs for the Ohio Companies ($51 million), and the asset transfer between MP and AE Supply ($23 million) as well as higher default generation service cost recovery in Pennsylvania, partially offset by a reduction of NUG cost recovery at ME and PN and higher transmission cost deferrals in Ohio.
- General taxes decreased by $9 million primarily due to lower gross receipts and payroll taxes, partially offset by higher property taxes.
- Impairment of long-lived assets of $322 million reflects MP's charge to reduce the net book value of Harrison to the amount permitted to be included in rate base.

Other Expense —

Other expense increased $24 million in 2013 primarily due to lower investment income resulting from the liquidation of investments at Shippingport and lower NDT investment income.

Regulated Transmission — 2013 Compared with 2012

Net income decreased $12 million in 2013 compared to 2012 principally due to higher operating expenses, such as depreciation and property taxes, associated with higher capital expenditures.

Revenues —

Total revenues decreased by $4 million principally due to lower PJM network service revenues for the Utilities, reflecting lower peak loads from the prior year.

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

Revenues by Transmission Asset Owner	**For the Years Ended December 31, 2013**	**2012**	**Increase (Decrease)**
		(In millions)	
ATSI	$ 209	$ 208	$ 1
TrAIL	207	200	7
PATH	20	18	2
Utilities	295	309	(14)
Total Revenues	$ 731	$ 735	$ (4)

Operating Expenses —

Total operating expenses increased $16 million principally due to higher depreciation and property taxes reflecting a higher asset base and higher amortization of the PATH abandonment regulatory asset.

CES — 2013 Compared with 2012

Net income decreased $435 million in 2013, compared to 2012. Impairment charges of $473 million associated with the deactivation of the Hatfield and Mitchell plants and a $149 million loss on debt redemptions were partially offset by lower Pension and OPEB mark-to-market adjustments of $322 million. Excluding these charges, year over year earnings were impacted by lower capacity revenue as a result of lower auction clearing prices, and lower unit pricing reflecting lower energy prices, partially offset by increased contract sales volumes.

Revenues —

Total revenues decreased $146 million in 2013, compared to 2012, primarily due to a decline in wholesale sales. Although MWH sales increased 5.8% compared to the prior period, revenues were adversely impacted by lower unit prices compared to 2012 as a result of a significant decrease in power prices beginning in the fourth quarter of 2011 when the 2013 competitive retail sales position was only approximately 50% committed. These decreases were partially offset by growth in Governmental Aggregation, Mass Market, and Structured Sales channels. The decrease in total revenues resulted from the following sources:

Revenues by Type of Service	For the Years Ended December 31, 2013	2012	Increase (Decrease)
	(In millions)		
Contract Sales:			
Direct	$ 2,913	$ 2,934	$ (21)
Governmental Aggregation	1,185	1,029	156
Mass Market	448	352	96
POLR	858	990	(132)
Structured Sales	421	275	146
Total Contract Sales	5,825	5,580	245
Wholesale[1]	341	751	(410)
Transmission	144	160	(16)
RECs	2	7	(5)
Other	186	146	40
Total Revenues	$ 6,498	$ 6,644	$ (146)

[1] Excludes wholesale revenues classified in Discontinued Operations.

MWH Sales by Channel	For the Years Ended December 31, 2013	2012	Increase (Decrease)
	(In thousands)		
Contract Sales:			
Direct	56,145	54,528	3.0 %
Governmental Aggregation	20,859	17,287	20.7 %
Mass Market	6,761	5,212	29.7 %
POLR	15,758	17,927	(12.1)%
Structured Sales	9,047	4,737	91.0 %
Total Contract Sales	108,570	99,691	8.9 %
Wholesale[1]	1,250	4,091	(69.4)%
Total MWH Sales	109,820	103,782	5.8 %

[1] Excludes wholesale sales classified in Discontinued Operations.

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

MWH Sales Channel:	Sales Volumes	Prices	Gain on Settled Contracts	Capacity Revenue	Total
	Source of Change in Revenues Increase (Decrease)				
	(In millions)				
Direct	$ 87	$ (108)	$ —	$ —	$ (21)
Governmental Aggregation	213	(57)	—	—	156
Mass Market	105	(9)	—	—	96
POLR	(120)	(12)	—	—	(132)
Structured Sales	250	(104)	—	—	146
Wholesale[1]	(74)	4	(204)	(136)	(410)

[1] Excludes wholesale sales classified in Discontinued Operations.

The decrease in Direct revenues of $21 million resulted from lower unit prices, partially offset by higher sales volumes due to the acquisition of new larger customers in central and southern Ohio. The increase in Governmental Aggregation of $156 million resulted from the acquisition of new customers primarily in Illinois, partially offset by lower unit prices. The increase in Mass Market of $96 million resulted from the acquisition of new customers primarily in Ohio, Illinois and Pennsylvania, partially offset by lower unit prices. The Direct, Governmental Aggregation and Mass Market customer base increased to 2.7 million customers as of December 31, 2013, as compared to 2.6 million as of December 31, 2012.

The decrease in POLR revenues of $132 million was due to slightly lower prices and lower sales volumes in line with FES' strategy to realign its sales portfolio. The increase in Structured Sales revenues of $146 million was due to higher sales volume, partially offset by lower prices.

Wholesale revenues decreased $410 million due to a $204 million reduction in gains on financially settled contracts, a $136 million decrease in capacity revenues primarily from lower capacity prices, and a $70 million decrease in short-term (net hourly positions) transactions. The decrease in wholesale sales volumes was due to lower generation available for sale primarily as a result of the asset transfer between MP and AE Supply, plants that were deactivated in 2012 and 2013, and those under RMR arrangements, and higher retail sales volumes.

Transmission revenue decreased $16 million due primarily to lower congestion and ancillary revenue.

Other revenue increased $40 million due primarily to a pre-tax gain on the sale of property to a regulated affiliate.

Operating Expenses —

Total operating expenses increased $370 million in 2013 due to the following:

- Fuel costs decreased $89 million primarily due to lower volumes associated with plants that were deactivated in 2013 and 2012, those under RMR arrangements, the asset transfer between MP and AE Supply and lower unit prices associated with new and restructured contracts, partially offset by settlements associated with past damages on transportation contracts.

- Purchased power costs increased $118 million due to higher volumes ($402 million) and increased prices ($81 million), partially offset by reduced losses on financially settled contracts ($239 million) and lower capacity expenses ($126 million). The increase in rate primarily resulted from higher on-peak prices compared to 2012. The increase in purchased power volumes relates to the overall increase in sales volumes and decrease in fossil generation.

- Fossil operating costs decreased $25 million due primarily to lower labor costs resulting from previously deactivated units and lower compensation and benefit expenses associated with plan changes.

- Nuclear operating costs decreased $21 million due primarily to lower labor costs and lower compensation and benefit expenses associated with plan changes.

- Transmission expenses increased $101 million due primarily to higher retail load and higher network costs associated with POLR sales in Pennsylvania, partially offset by lower congestion costs as well as credits received in 2013 for previously incurred PJM transmission costs associated with RMR units in the ATSI zone. Effective June 1, 2013, network transmission costs became the responsibility of suppliers of POLR sales in Pennsylvania.

- Impairments of long-lived assets increased $473 million due to the decision to deactivate the Hatfield and Mitchell generating plants. The plants were deactivated on October 9, 2013.
- General taxes decreased $7 million primarily due to lower payroll taxes as a result of lower labor costs noted above, partially offset by higher property taxes.
- Depreciation expense increased $30 million primarily due to a higher asset base and accelerated depreciation associated with the deactivations noted above.
- Other operating expenses decreased $210 million primarily due to a $322 million decrease in pension and OPEB mark-to-market charges primarily reflecting a higher discount rate to measure related obligations in 2013, partially offset by an increase in mark-to-market expense on commodity contract positions ($98 million) and increased retail expenses ($26 million).

Other Expense —

Total other expense in 2013 increased $144 million compared to 2012 due to a $149 million loss on debt redemptions in connection with senior notes that were repurchased, lower investment income of $55 million due to higher OTTI on NDT investments, partially offset by lower net interest expense of $60 million due to debt redemptions and repurchases.

Corporate/Other — 2013 Compared with 2012

Financial results from Corporate/Other resulted in a $107 million increase in net income in 2013 compared to 2012 primarily due to tax benefits and increased investment income of $39 million. Higher tax benefits were primarily due to changes in state income tax allocation factors, the elimination of state obligations associated with income that was previously apportioned to certain tax jurisdictions partially offset by valuation reserves against NOL carryforwards. Partially offsetting this increase was higher interest expense of $73 million due to the issuance of $1.5 billion of senior unsecured notes in the first quarter of 2013.

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, 2014 and December 31, 2013, and the changes during the year ended December 31, 2014:

Regulatory Assets (Liabilities) by Source	**December 31, 2014**	**December 31, 2013**	**Increase (Decrease)**
		(In millions)	
Regulatory transition costs	$ 240	$ 266	$ (26)
Customer receivables for future income taxes	370	518	(148)
Nuclear decommissioning and spent fuel disposal costs	(305)	(198)	(107)
Asset removal costs	(254)	(362)	108
Deferred transmission costs	90	112	(22)
Deferred generation costs	281	346	(65)
Deferred distribution costs	182	194	(12)
Contract valuations	153	260	(107)
Storm-related costs	465	455	10
Other	189	263	(74)
Net Regulatory Assets included in the Consolidated Balance Sheet	$ 1,411	$ 1,854	$ (443)

Regulatory assets that do not earn a current return totaled approximately $488 million and $477 million as of December 31, 2014 and 2013, respectively, primarily related to storm damage costs of which approximately $360 million relates to JCP&L for which the recovery period is subject to current rate and regulatory proceedings (see Note 14, Regulatory Matters).

As of December 31, 2014 and December 31, 2013, FirstEnergy had approximately $243 million and $440 million of net regulatory liabilities that are primarily related to asset removal costs and are classified within other noncurrent liabilities on the Consolidated Balance Sheets, as opposed to being included in the net regulatory assets shown above.

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. FE's primary source of cash for continuing operations as a holding company is cash from the operations of its subsidiaries. During 2014, FirstEnergy received $735 million of cash dividends and capital returned from its subsidiaries and paid $604 million in cash dividends to common shareholders. In addition to internal sources to fund liquidity and capital requirements for 2015 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.

In January 2014, FirstEnergy's Board of Directors declared a revised quarterly dividend of $0.36 per share of outstanding common stock. This revised dividend equates to an indicated annual dividend of $1.44 per share, reduced from the $0.55 per share quarterly dividend ($2.20 per share annually) that FirstEnergy had paid since 2008. Most recently, FirstEnergy's Board of Directors declared a quarterly dividend of $0.36 per share of outstanding common stock in January 2015 payable March 1, 2015 to shareholders of record at the close of business on February 6, 2015.

FirstEnergy's strategy is to focus on investments in its regulated operations. The centerpiece of this strategy is a $4.2 billion *Energizing the Future* investment plan that began in 2014 and will continue through 2017 to upgrade and expand the transmission system owned by FirstEnergy's Regulated Transmission segment. This program is focused on projects that enhance system performance, physical security and add operating flexibility and capacity starting with the ATSI system and moving east across FirstEnergy's service territory over time. FirstEnergy expects to fund these investments through a combination of debt, previously announced equity issuances through a stock investment plan and, to the extent available, employee benefit plans, and cash. Regulated Transmission's capital expenditures in 2014 were approximately $1.4 billion. In 2015, Regulated Transmission's capital expenditure forecast is approximately $970 million. In total, FirstEnergy has identified at least $15 billion in transmission investment opportunities across the 24,000 mile transmission system, making this a continuing platform for investment in the years beyond 2017. In the future, FirstEnergy may consider additional equity to fund capital investments in the Regulated Transmission business.

In alignment with FirstEnergy's strategy to invest in its Regulated Transmission and Regulated Distribution segments and the repositioning of the CES segment, FirstEnergy is also focused on improving the balance sheet over time consistent with its business profile, maintaining investment grade metrics at each business unit, and maintaining strong liquidity for an overall stable financial position. Specifically, at the regulated businesses, authority has been obtained for various regulated distribution and transmission subsidiaries to issue and/or refinance debt.

Capital expenditures for 2015 are expected to be approximately $2.9 billion, a decrease of $0.4 billion from 2014, excluding the capital component of the Pension and OPEB mark-to-market adjustment, which increased 2014 capital by $387 million. These capital expenditures, including this transmission expansion program, are expected to be funded with a combination of debt, equity issuances through the stock investment plan and, to the extent available, employee benefit plans, and the projected $320 million annually in cash preserved as a result of the dividend action taken in January 2014. In 2014, FirstEnergy issued $83 million in equity through the stock investment plan and share-based employee benefit plans.

The Utilities and FirstEnergy's competitive generation operations expect to fund their capital expenditures over the next several years through cash from operations, debt, and, depending on the operating company, equity contributions from FE. Additionally, FirstEnergy also expects to issue long-term debt at certain Utilities and certain other subsidiaries to refinance short-term and maturing debt in the ordinary course, subject to market and other conditions.

Any financing plans by FirstEnergy, including refinancing of maturing debt and reductions in short-term borrowings, are subject to market conditions and other factors. No assurance can be given that any such financings, refinancings, or reductions in short-term debt, as the case may be, will be completed as anticipated. In addition, FirstEnergy expects to continually evaluate any planned financings, which may result in changes from time to time.

As of December 31, 2014, 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, 2014, included the following:

Currently Payable Long-Term Debt	(In millions)
PCRBs supported by bank LOCs (1)	$ 92
FMBs	215
Unsecured PCRBs (1)	313
Collateralized lease obligation bonds	78
Sinking fund requirements	102
Other notes	4
	$ 804

(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

FE and certain of its subsidiaries participate in three five-year syndicated revolving credit facilities with aggregate commitments of $6.0 billion (Facilities), which are available until March 31, 2019. FirstEnergy had $1,799 million and $3,404 million of short-term borrowings under the Facilities as of December 31, 2014 and 2013, respectively. FirstEnergy's available liquidity under the Facilities as of January 31, 2015 was as follows:

Borrower(s)	Type	Maturity	Commitment	Available Liquidity
			(In millions)	
FirstEnergy(1)	Revolving	March 2019	$ 3,500	$ 1,469
FES / AE Supply	Revolving	March 2019	1,500	1,435
FET(2)	Revolving	March 2019	1,000	1,000
		Subtotal	$ 6,000	$ 3,904
		Cash	—	58
		Total	$ 6,000	$ 3,962

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

Revolving Credit Facilities

FirstEnergy, FES/AE Supply and FET Facilities

On March 31, 2014, FE, FES, AE Supply, FET and FE's other borrower subsidiaries entered into extensions and amendments to the three existing multi-year syndicated revolving credit facilities. Each Facility was extended until March 31, 2019. The FE facility was amended to increase the lending banks' commitments under the facility by $1.0 billion to a total of $3.5 billion and to increase the individual borrower sublimit for FE by $1.0 billion to a total of $3.5 billion. The FES/AE Supply facility was amended to decrease the lending banks' commitments by $1.0 billion to a total of $1.5 billion. The lending banks' commitments under the FET facility remain at $1.0 billion and that facility was amended to increase ATSI's individual borrower sublimit to $500 million from $100 million and TrAIL's individual borrower sublimit to $400 million from $200 million. FirstEnergy expensed approximately $5 million (FES - $3 million) of unamortized debt expense as a result of the amendments, included in Loss on Debt Redemptions in the Consolidated Statement of Income for the year ended December 31, 2014.

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 (as defined under each of the Facilities, as amended) of no more than 65%, and 75% 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 of December 31, 2014:

Borrower	FirstEnergy Revolving Credit Facility Sub-Limit	FES/AE Supply Revolving Credit Facility Sub-Limit	FET Revolving Credit Facility Sub-Limit	Regulatory and Other Short-Term Debt Limitations
	(In millions)			
FE	$ 3,500	$ —	$ —	$ — (1)
FES	—	1,500	—	— (2)
AE Supply	—	1,000	—	— (2)
FET	—	—	1,000	— (1)
OE	500	—	—	500 (3)
CEI	500	—	—	500 (3)
TE	500	—	—	500 (3)
JCP&L	600	—	—	850 (3)
ME	300	—	—	500 (3)
PN	300	—	—	300 (3)
WP	200	—	—	200 (3)
MP	500	—	—	500 (3)
PE	150	—	—	150 (3)
ATSI	—	—	500	500 (3)
Penn	50	—	—	50 (3)
TrAIL	—	—	400	400 (3)

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

The entire amount of the FES/AE Supply Facility, $600 million of the FE Facility and $225 million of the FET Facility, subject to each borrower's sub-limit, is available for the issuance of LOCs (subject to borrowings drawn under the Facilities) 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.

As of December 31, 2014, the borrowers were in compliance with the financial covenants associated with the applicable debt to total capitalization ratios under the respective Facilities.

Term Loans

On March 31, 2014, FE executed, and fully utilized, a new $1 billion variable rate term loan credit agreement with a maturity date of March 31, 2019. The initial borrowing under the term loan, which took the form of a Eurodollar rate advance, may be converted from time to time, in whole or in part, to alternate base rate advances or other Eurodollar rate advances. The proceeds from this term loan reduced borrowings under the FE Facility. Additionally, FE has a $200 million variable rate term loan, for which the maturity was extended in December 2014 for an additional year to December 31, 2016. The term loan contains covenants and other terms and conditions substantially similar to FE's $1 billion variable rate term loan entered into on March 31, 2014 and FE's existing revolving credit facility, including the same consolidated debt to total capitalization ratio requirement.

As of December 31, 2014, FE was in compliance with the financial covenants associated with the applicable debt to total capitalization ratios under each of these term loans.

FirstEnergy Money Pools

FirstEnergy's utility operating subsidiary 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 2014 was 1.45% per annum for the regulated companies' money pool and 1.35% per annum for the unregulated companies' money pool.

Pollution Control Revenue Bonds

As of December 31, 2014, FirstEnergy's currently payable long-term debt included approximately $92 million of FES 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, 2014 were issued by the following banks:

Bank	Aggregate Amount[1]	Termination Date	Reimbursements of Draws Due
	(In millions)		
The Bank of Nova Scotia	52	April 2015	April 2015
The Bank of Nova Scotia	40	December 2015	December 2015
Total	$ 92		

[1] Excludes approximately $1 million of applicable interest coverage.

Long-Term Debt Capacity

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 December 31, 2014:

	Senior Secured			Senior Unsecured		
Issuer	**S&P**	**Moody's**	**Fitch**	**S&P**	**Moody's**	**Fitch**
FE	—	—	—	BB+	Baa3	BB+
FES	—	—	—	BBB-	Baa3	—
AE Supply	—	—	—	BBB-	Baa3	—
AGC	—	—	—	BBB-	Baa3	—
ATSI	—	—	—	BBB-	Baa2	—
CEI	BBB+	Baa1	—	BBB-	Baa3	—
FET	—	—	—	BB+	Baa3	
JCP&L	—	—	—	BBB-	Baa2	—
ME	—	—	—	BBB-	Baa1	—
MP	BBB+	A3	—	—	—	—
OE	BBB+	A2	—	BBB-	Baa1	—
PN	—	—	—	BBB-	Baa2	—
Penn	BBB+	A2	—	—	—	—

PE	BBB+	A3	—	—	—	—
TE	BBB	Baa1	—	—	—	—
TrAIL	—	—	—	BBB-	A3	—
WP	BBB+	A2	—	—	—	—

Debt capacity is subject to the consolidated debt to total capitalization limits in the Facilities previously discussed. As of December 31, 2014, FE and its subsidiaries could issue additional debt of approximately $4.9 billion and remain within the limitations of the financial covenants required by the Facilities, as amended. As of December 31, 2014, FES' incremental debt capacity under its consolidated debt to total capitalization financial covenant is also $4.9 billion given FE's consolidated debt to total capitalization ratio under its Facility, as amended.

Changes in Cash Position

As of December 31, 2014, FirstEnergy had $85 million of cash and cash equivalents compared to $218 million of cash and cash equivalents as of December 31, 2013. As of December 31, 2014 and 2013, FirstEnergy had approximately $79 million and $103 million, respectively, of restricted cash included in Other Current Assets on the Consolidated Balance Sheets.

Cash Flows From Operating Activities

Net cash provided from operating activities was $2,713 million during 2014, $2,662 million during 2013 and $2,320 million during 2012. Cash flows from operations increased $51 million in 2014 compared with 2013 primarily due to:

- An increase in Regulated Distribution and Regulated Transmission sales associated with higher weather-related usage as well as improving economic conditions in 2014, complemented by a year-over-year improvement in receivables collections,
- Absence in 2014 of make-whole premiums paid on debt redemptions (2013); partially offset by
- Increases in purchase power and transmission expenses due to higher volumes, increased prices and higher capacity expenses resulting from the extreme weather-related events in January 2014 that significantly impacted the wholesale market as discussed above.

Cash Flows From Financing Activities

In 2014, cash provided from financing activities was $513 million compared to $477 million of net cash provided from financing activities during 2013. The following table summarizes new debt financing (net of any discounts), redemptions and common stock dividend payments:

	For the Years Ended December 31,		
Securities Issued or Redeemed / Repaid	**2014**	**2013**	**2012**
		(In millions)	
New Issues			
PCRBs	$ 878	$ —	$ 650
Term loan	1,050	—	—
Senior secured notes	—	445	—
FMBs	200	1,000	100
Unsecured Notes	2,400	2,300	—
	$ 4,528	$ 3,745	$ 750
Redemptions / Repayments			
PCRBs	$ (793)	$ (470)	$ (238)
Long-term revolving credit	—	(50)	—
Senior secured notes	(191)	(376)	(118)
FMBs	(175)	(420)	—
Unsecured notes	(600)	(2,284)	(584)
	$ (1,759)	$ (3,600)	$ (940)
Tender premiums paid on debt redemptions	$ —	$ (110)	$ —
Short-term borrowings, net	$ (1,605)	$ 1,435	$ 1,969

Common stock dividend payments	$ (604)	$ (920)	$ (920)

On March 31, 2014, FE, FES, AE Supply, FET and FE's other borrower subsidiaries entered into extensions and amendments to the three existing multi-year syndicated revolving credit facilities. Each Facility was extended until March 31, 2019. The FE facility was amended to increase the lending banks' commitments under the facility by $1 billion to a total of $3.5 billion and to increase the individual borrower sublimit for FE by $1 billion to a total of $3.5 billion. The FES/AE Supply facility was amended to decrease the lending banks' commitments by $1 billion to a total of $1.5 billion. The lending banks' commitments under the FET facility remain at $1 billion and that facility was amended to increase ATSI's individual borrower sublimit to $500 million from $100 million and TrAIL's individual borrower sublimit to $400 million from $200 million. FirstEnergy expensed approximately $5 million (FES -$3 million) of unamortized debt expense as a result of the amendments, included in Loss on Debt Redemptions in the Consolidated Statement of Income for the year ended December 31, 2014.

On March 31, 2014, FE executed, and fully utilized, a new $1 billion variable rate term loan credit agreement with a maturity date of March 31, 2019. The initial borrowing under the term loan, which took the form of a Eurodollar rate advance, may be converted from time to time, in whole or in part, to alternate base rate advances or other Eurodollar rate advances. The proceeds from this term loan reduced borrowings under the FE Facility.

During the first quarter of 2014, FG and NG remarketed approximately $235 million and $182 million, respectively, of PCRBs, previously held by the companies. The NG PCRBs were remarketed with a fixed interest rate of 4% per annum and a mandatory put date of June 3, 2019 and the FG PCRBs were remarketed with a fixed interest rate of 3.75% per annum and a mandatory put date of December 3, 2018.

In addition, in the first quarter of 2014, FG and NG repurchased approximately $197 million and $16 million, respectively, of PCRBs, which were subject to a mandatory tender. The PCRBs have been remarketed in the second and third quarter as described below. Additionally, FG retired $50 million of PCRBs at maturity.

During the first quarter of 2014, AE Supply returned $500 million of capital to FE. Additionally, FE contributed $500 million of equity to FES.

On April 1, 2014, PN and ME repurchased approximately $45 million and $29 million of PCRBs, respectively, which were subject to a mandatory put on such date. The companies are currently holding the PCRBs for remarketing subject to future market and other conditions. Additionally, on April 1, 2014, ME retired $150 million of long-term debt at maturity.

On May 19, 2014, FET issued $600 million of 4.35% senior notes due 2025 and $400 million of 5.45% senior notes due 2044. Proceeds received from the issuance of the senior notes were used to (i) repay borrowings under its revolving credit facility and the FirstEnergy unregulated companies' money pool; (ii) fund a capital contribution to ATSI; and (iii) for working capital needs and other general business purposes.

On June 11, 2014, ME and PN issued $250 million of 4% senior notes due 2025 and $200 million of 4.15% senior notes due 2025, respectively. Proceeds received from the issuance of the senior notes were used to repay ME and PN's borrowings under the FirstEnergy revolving credit facility and the FirstEnergy regulated companies' money pool.

In addition, in the second quarter of 2014, FG and NG remarketed approximately $57 million and $164 million, respectively, of PCRBs previously held by the companies. The bonds were remarketed with a fixed interest rate of 3.50% per annum and a mandatory put date of June 1, 2020.

On September 25, 2014, ATSI issued $400 million of 5% senior notes due 2044. Proceeds received from the issuance of the senior notes were used: (i) to fund capital expenditures, including capital expenditures related to its transmission investment plans; and (ii) for working capital needs and other general business purposes.

Also during the third quarter, FG and NG remarketed approximately $140.1 million and $101 million, respectively, of PCRBs. Of the total, approximately $45 million of PCRBs were remarketed by NG with a fixed interest rate of 3.63%, of which $15.5 million has a mandatory put date of June 1, 2020 and $29.5 million has a mandatory put date of April 1, 2020. NG also remarketed $56 million of PCRBs with a fixed interest rate of 3.95% and a mandatory put date of May 1, 2020; FG remarketed $50 million of PCRBs with a fixed interest rate of 3.10% and a mandatory put date of March 1, 2019; and $90.1 million of PCRBs with a fixed interest rate of 3.00% and a maturity date of May 15, 2019.

On November 25, 2014, PE issued $200 million of 4.44% FMBs due November 15, 2044. Proceeds received from the issuance of the FMBs were used: (i) to refinance PE's outstanding $175 million of 5.35% FMBs due November 15, 2014; (ii) to repay PE's borrowings under the FirstEnergy regulated companies' money pool; and (iii) for other general business purposes.

On December 1, 2014, NG repurchased approximately $26 million PCRBs, which were subject to a mandatory put on such date. NG is currently holding these PCRBs for remarketing subject to future market and other conditions.

On December 11, 2014, TrAIL issued $550 million of 3.85% senior notes due June 1, 2025. Proceeds received from the issuance of the senior notes were used: (i) to repay TrAIL's outstanding $450 million of 4.00% senior notes due January 15, 2015; (ii) to fund capital expenditures; and (iii) for working capital needs and other general business purposes.

On December 19, 2014, the maturity date for a $200 million term loan agreement for which FE is the borrower was extended an additional year to December 31, 2016.

Cash Flows From Investing Activities

Cash used for investing activities in 2014 principally represented cash used for property additions. The following table summarizes investing activities for 2014, 2013 and 2012:

	For the Years Ended December 31,		
Cash Used for Investing Activities	**2014**	**2013**	**2012**
		(In millions)	
Property Additions:			
Regulated distribution	$ 972	$ 1,272	$ 1,074
Regulated transmission	1,329	461	507
Competitive energy services	939	827	1,014
Other and reconciling adjustments	72	78	83
Nuclear fuel	233	250	286
Proceeds from asset sales	(394)	(4)	(17)
Investments	68	72	(62)
Asset removal costs	153	146	229
Other	(13)	(9)	43
	$ 3,359	$ 3,093	$ 3,157

Net cash used for investing activities during 2014 increased by $266 million compared to 2013 primarily due to increased property additions of $648 million primarily at the Regulated Transmission segment associated with its *Energizing the Future* investment plan, partially offset by proceeds received from the sale of hydro assets in the first quarter of 2014.

CONTRACTUAL OBLIGATIONS

As of December 31, 2014, our estimated cash payments under existing contractual obligations that we consider firm obligations are as follows:

Contractual Obligations	**Total**	**2015**	**2016-2017**	**2018-2019**	**Thereafter**
			(In millions)		
Long-term debt[(1)]	$ 19,807	$ 769	$ 2,882	$ 3,953	$ 12,203
Short-term borrowings	1,799	1,799	—	—	—
Interest on long-term debt[(2)]	12,798	1,008	1,901	1,563	8,326
Operating leases[(3)]	2,227	205	303	237	1,482
Fuel and purchased power[(4)]	17,229	2,206	3,425	2,844	8,754
Capital expenditures	4,638	1,555	2,261	786	36
Pension funding	2,212	144	879	646	543
Other[(5)]	210	46	72	52	40
Total	$ 60,920	$ 7,732	$ 11,723	$ 10,081	$ 31,384

(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, 2014.
(3) See Note 6, 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 6, Leases, of the Combined Notes to Consolidated Financial Statements) and contingent tax liabilities (see Note 5, Taxes, of the Combined Notes to Consolidated Financial Statements).

Excluded from the table 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 $3.4 billion in 2015, $0.6 billion of which are expected to relate to the Utilities' contracts with FES.

The table above also excludes regulatory liabilities (see Note 14, Regulatory Matters), AROs (see Note 13, Asset Retirement Obligations), reserves for litigation, injuries and damages, environmental remediation, and annual insurance premiums, including nuclear insurance (see Note 15, Commitments, Guarantees and Contingencies) since the amount and timing of the cash payments are uncertain. The table also excludes accumulated deferred income taxes and investment tax credits since cash payments for income taxes are determined based primarily on taxable income for each applicable fiscal year.

NUCLEAR INSURANCE

The Price-Anderson Act limits the public liability which can be assessed with respect to a nuclear power plant to $13.6 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) $13.2 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 $127 million (but not more than $19 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 $509 million (NG-$501 million) per incident but not more than $76 million (NG-$75 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 annually, corresponding to their respective nuclear interests, which provide an aggregate indemnity of up to approximately $1.96 billion (NG-$1.93 billion) for replacement power costs incurred during an outage after an initial 20-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 (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 $74 million (NG-$72 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.

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 be required to make under these guarantees as of December 31, 2014, was approximately $4.0 billion, as summarized below:

Guarantees and Other Assurances	Maximum Exposure
	(In millions)
FE's Guarantees on Behalf of its Subsidiaries	
Energy and Energy-Related Contracts[1]	$ 166
Deferred compensation arrangements	522
Other[2]	24
	712
Subsidiaries' Guarantees	
Energy and Energy-Related Contracts[3]	177
FES' guarantee of NG's nuclear property insurance	88
Nuclear decommissioning costs[4]	174
FES' guarantee of FG's sale and leaseback obligations	1,899
	2,338
FE's Guarantees on Behalf of Business Ventures	
Global Holding Facility	300
Other Assurances	
Surety Bonds - Wholly Owned Subsidiaries	447
Surety Bonds	24
FES' LOC (long-term tax-exempt debt)[5]	93
LOCs[6]	85
	649
Total Guarantees and Other Assurances	$ 3,999

(1) Issued for open-ended terms, with a 10-day termination right by FirstEnergy.
(2) Includes guarantees of $4 million for nuclear decommissioning funding assurances, $11 million for railcar leases, and $9 million for various leases.
(3) Includes Energy and Energy-Related Contracts associated with FES of approximately $173 million.
(4) These guarantees of $174 million replace guarantees of $136 million for nuclear decommissioning funding assurances previously provided only by FE. The increase of $38 million over the prior guarantees relates primarily to a $30 million shortfall of estimated nuclear decommissioning funding and a new guaranty of $8 million relating to spent fuel storage facilities at Beaver Valley.
(5) Reflects the $1 million of interest coverage portion of LOCs issued in support of floating rate PCRBs with maturities in 2015 and the principal amount of floating-rate PCRBs of $92 million, all of which is reflected in currently payable long-term debt on FirstEnergy's consolidated balance sheets.
(6) Includes $57 million issued for various terms pursuant to LOC capacity available under FirstEnergy's revolving credit facilities, $11 million pledged in connection with the sale and leaseback of the Beaver Valley Unit 2 by OE and $17 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

In the normal course of business, FE 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 FE or its subsidiaries to post collateral. This collateral may be posted in the form of cash or credit support with thresholds contingent upon FE'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 FE and its subsidiaries have margining provisions that require posting of collateral. Based on FES' power portfolio exposure as of December 31, 2014, FES has posted collateral of $175 million and AE Supply has posted no collateral. The Regulated Distribution segment has posted collateral of $1 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, or a "material adverse event," the immediate posting of collateral or accelerated payments may be required of FE or its subsidiaries. The following table discloses the additional credit contingent contractual obligations that may be required under certain events as of December 31, 2014:

Collateral Provisions	FES	AE Supply	Utilities	Total
		(In millions)		
Split Rating (One rating agency's rating below investment grade)	$ 603	$ 6	$ 48	$ 657
BB+/Ba1 Credit Ratings	$ 643	$ 6	$ 48	$ 697
Full impact of credit contingent contractual obligations	$ 886	$ 72	$ 86	$ 1,044

Excluded from the preceding chart are the potential collateral obligations due to affiliate transactions between the Regulated Distribution segment and CES segment. As of December 31, 2014, 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 would be required to post $24 million with affiliated parties.

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, 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 current 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 current 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 no later than July 20, 2015, which reflects the terms of an amendment dated August 14, 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 accrued at a rate of 4% through December 31, 2012, and accrues at a rate of 5% from January 1, 2013 through October 18, 2015, which amends the rate in the prior agreement, 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 the Perry Unit 1, Beaver Valley Unit 2, and 2007 Bruce Mansfield Unit 1 sale and leaseback arrangements, 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 billion as of December 31, 2014 and primarily relates to the 2007 Bruce Mansfield Unit 1 sale and leaseback arrangement expiring in 2040. From time to time FirstEnergy and these companies enter into discussions with certain parties to the arrangements regarding acquisition of owner participant and other interests. However, FirstEnergy cannot provide assurance that any such acquisitions will occur on satisfactory terms or at all.

In February 2014, NG purchased lessor equity interests in OE's existing sale and leaseback of Beaver Valley Unit 2 for approximately $94 million. In November 2014, NG repurchased lessor equity interests in OE's existing sale and leaseback of Perry Unit 1 for approximately $87 million. As of December 31, 2014, FirstEnergy's leasehold interest was 3.75% of Perry Unit 1, 93.83% of Bruce Mansfield Unit 1 and 2.60% of Beaver Valley Unit 2.

On June 24, 2014, OE exercised its irrevocable right to repurchase from the remaining owner participants the lessors' interests in Beaver Valley Unit 2 at the end of the lease term (June 1, 2017), which right to repurchase was assigned to NG. Additionally, on June 24, 2014, NG entered into a purchase agreement with an owner participant to purchase its lessor equity interests of the remaining non-affiliated leasehold interest in Perry Unit 1 on May 23, 2016, which is just prior to the end of the lease term.

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 9, Fair Value Measurements, of the Combined Notes to Consolidated Financial Statements). Sources of information for the valuation of net commodity derivative contracts assets and liabilities as of December 31, 2014 are summarized by year in the following table:

Source of Information-Fair Value by Contract Year	**2015**	**2016**	**2017**	**2018**	**2019**	**Thereafter**	**Total**
				(In millions)			
Prices actively quoted[(1)]	$ (25)	$ —	$ —	$ —	$ —	$ —	$ (25)
Other external sources[(2)]	(63)	(15)	(19)	(14)	—	—	(111)
Prices based on models	28	2	2	—	(14)	(3)	15
Total[(3)]	$ (60)	$ (13)	$ (17)	$ (14)	$ (14)	$ (3)	$ (121)

(1) Represents exchange traded New York Mercantile Exchange futures and options.
(2) Primarily represents contracts based on broker and ICE quotes.
(3) Includes $(151) million in non-hedge derivative contracts that are primarily related to NUG contracts. NUG contracts are subject to regulatory accounting and do not impact earnings.

FirstEnergy performs sensitivity analyses to estimate its exposure to the market risk of its commodity positions. Based on derivative contracts as of December 31, 2014, not subject to regulatory accounting, a 10% adverse change in commodity prices would increase net income by approximately $1 million during the next 12 months.

Equity Price Risk

As of December 31, 2014, the FirstEnergy pension and OPEB plan assets were approximately allocated as follows: 37% in equity securities, 33% in fixed income securities, 14% in absolute return strategies, 7% in real estate and 9% in cash and short-term securities. A decline in the value of 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, 2014, FirstEnergy made no contributions to its qualified pension plans. See Note 3, Pension and Other Postemployment Benefits, of the Combined Notes to Consolidated Financial Statements for additional details on FirstEnergy's pension plans and OPEB. In 2014, FirstEnergy's pension plan and OPEB assets earned approximately 6.2% as compared to an expected return on plan assets of 7.75%.

NDT funds have been established to satisfy NG's and other FirstEnergy subsidiaries' nuclear decommissioning obligations. As of December 31, 2014, approximately 66% of the funds were invested in fixed income securities, 26% of the funds were invested in equity securities and 8% 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 $1,520 million, $591 million and $190 million for fixed income securities, equity securities and short-term investments, respectively, as of December 31, 2014, excluding $40 million of net receivables, payables and accrued income. A hypothetical 10% decrease in prices quoted by stock exchanges would result in a $59 million reduction in fair value as of December 31, 2014. Certain FirstEnergy subsidiaries recognize in earnings the unrealized losses on AFS securities held in its 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 2014, FirstEnergy contributed approximately $8 million to the NDT.

Interest Rate Risk

FirstEnergy's exposure to fluctuations in market interest rates is reduced since a significant portion of debt has fixed interest rates, as noted in the table below. FirstEnergy is subject to the inherent interest rate risks related to refinancing maturing debt by issuing new debt securities. As discussed in Note 6, Leases of the Combined Notes to 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	2015	2016	2017	2018	2019	There-after	Total	Fair Value
				(In millions)				
Assets:								
Investments Other Than Cash and Cash Equivalents:								
Fixed Income	$ 6	$ 5	$ 2	$ —	$ —	$ 1,751	$ 1,764	$ 1,768
Average interest rate	8.8%	8.9%	8.9%	—%	—%	3.8%	4.9%	
Liabilities:								
Long-term Debt:								
Fixed rate	$ 381	$ 662	$ 1,517	$ 1,329	$ 1,035	$ 13,612	$ 18,536	$ 20,441
Average interest rate	5.3%	5.5%	6.1%	4.8%	6.5%	5.2%	5.3%	
Variable rate	$ —	$ 200	—	6	$ 1,000	$ 86	$ 1,292	$ 1,292
Average interest rate	—%	1.7%	—%	—%	1.9%	—%	1.7%	

CREDIT RISK

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

Wholesale Credit Risk

FirstEnergy and FES measure 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 and FES have a legally enforceable right of offset. FirstEnergy and FES monitor and manage 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's and FES' portfolio of energy contracts has a current weighted average risk rating of A (S&P) for energy contract counterparties.

Retail Credit Risk

FirstEnergy's and FES' 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 and FES' 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 any of the FirstEnergy affiliates were to engage in the construction of significant new transmission or generation facilities, depending on the state, they may be required to obtain state regulatory authorization to site, construct and operate the new transmission or generation facility.

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 adopted a statute in 2008 codifying the EmPOWER Maryland goals to reduce electric consumption by 10% and reduce electricity demand by 15%, in each case by 2015. PE's initial plan submitted in compliance with the statute was approved in 2009, at which time expenditures were estimated to be approximately $101 million for the PE programs for the entire period of 2009-2015. PE's third plan, covering the three-year period 2015-2017, was approved by the MDPSC on December 23, 2014. The projected costs of the 2015-2017 plan are approximately $64 million for that three year period. PE continues to recover program costs subject to a five-year amortization. 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.

The MDPSC adopted rules, effective May 28, 2012, that set utility-specific SAIDI and SAIFI targets for 2012-2015; prescribed detailed tree-trimming requirements, outage restoration and downed wire response deadlines; imposed other reliability and customer satisfaction requirements; and established annual reporting requirements. The MDPSC is required to assess each utility's compliance with the new rules, and may assess penalties of up to $25,000 per day, per violation. The MDPSC issued orders accepting PE's reports on compliance under the new rules on September 3, 2013 and August 27, 2014.

On February 27, 2013, the MDPSC issued an order (the February 27 Order) requiring the Maryland electric utilities to submit analyses, relating to the costs and benefits of making further system and staffing enhancements in order to attempt to reduce storm outage durations. The order further required the Staff of the MDPSC to report on possible performance-based rate structures and to propose additional rules relating to feeder performance standards, outage communication and reporting, and sharing of special needs customer information. PE's final filing on September 3, 2013, discussed the steps needed to harden the utility's system in order to attempt to achieve various levels of storm response speed described in the February 27 Order, and projected that it would require approximately $2.7 billion in infrastructure investments over 15 years to attempt to achieve the quickest level of response for the largest storm projected in the February 27 Order. On July 1, 2014, the Staff of the MDPSC issued a set of reports that recommended the imposition of extensive additional requirements in the areas of storm response, feeder performance, estimates of restoration times, and regulatory reporting. The Staff also recommended the imposition of penalties, including customer rebates, for a utility's failure or inability to comply with the escalating standards of storm restoration speed proposed by the Staff. In addition, the Staff proposed that the utilities be required to develop and implement system hardening plans, up to a rate impact cap on cost. The MDPSC conducted a hearing September 15-18, 2014, to consider certain of these matters, and has not yet scheduled further proceedings on any of the matters.

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.

In an order issued July 31, 2012, the NJBPU 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 by JCP&L requesting approval to increase revenues by approximately $31 million, which included the recovery of 2011 storm restoration costs but excluded approximately $603 million of costs incurred in 2012 associated with the impact of Hurricane Sandy. In the initial briefs of the parties, the Division of Rate Counsel recommended that base rate revenues be reduced by $214.9 million while the NJBPU Staff recommended a $207.4 million reduction (such amounts do not address the revenue requirements associated with the major storm events of 2011 and 2012). On May 5, 2014, JCP&L submitted updated schedules to reflect the result of the generic storm cost proceeding, discussed below, to revise the debt rate to 5.93%, and to request that base rate revenues be increased by $9.1 million, including the recovery of 2011 storm costs. The record in the case was closed as of June 30, 2014. The ALJ provided his initial Decision on January 8, 2015, which recommended an annual revenue reduction of $107.5 million and did not include the recovery of 2012 storm costs or any CTA. On February 11, 2015, the NJBPU approved a 45-day extension to render a final decision.

On January 23, 2013, the NJBPU opened a generic proceeding to review its policies with respect to the use of a CTA in base rate cases. The NJBPU and its Staff solicited, and were provided, input from interested stakeholders, including utilities and the Division of Rate Counsel. On June 18, 2014, the NJBPU Staff proposed to amend current CTA policy by: 1) calculating savings using a 5 year look back from the beginning of the test year; 2) allocating savings with 75% retained by the company and 25% allocated to rate payers; and 3) excluding transmission assets of electric distribution companies in the savings calculation. JCP&L and other stakeholders filed written comments on the Staff proposal. In its Order issued October 22, 2014, the NJBPU stated it would continue to apply its current CTA policy in base rate cases, subject to incorporating the staff proposed modifications (as discussed above). For pending base rate cases in which the record had closed, such as JCP&L's, the NJBPU would, following an initial decision of the ALJ, reopen the record for the limited purpose of adding a CTA calculation reflecting the modified policy and allow parties the opportunity to comment. FirstEnergy expects the application of the modified policy in the pending JCP&L base rate case to reduce annual revenues by approximately $5 million. On November 5, 2014, the Division of Rate Counsel appealed the NJBPU Order to the New Jersey Superior Court. JCP&L has filed to participate as a respondent in that proceeding.

On March 20, 2013, the NJBPU ordered that a generic proceeding be established to investigate the prudence of costs incurred by all New Jersey utilities for service restoration efforts associated with the major storm events of 2011 and 2012. The Order provided that if any utility had already filed a proceeding for recovery of such storm costs, to the extent the amount of approved recovery had not yet been determined, the prudence of such costs would be reviewed in the generic proceeding. On May 31, 2013, the NJBPU clarified its earlier order to indicate that the 2011 major storm costs would be reviewed expeditiously in the generic proceeding, with the goal of maintaining the base rate case schedule established by the ALJ where recovery of such costs would be addressed. The NJBPU further indicated that it would review the 2012 major storm costs in the generic proceeding and the recovery of such costs would be considered through a Phase II in the existing base rate case or through another appropriate method to be determined at the conclusion of the generic proceeding. On June 21, 2013, JCP&L filed a detailed report in support of recovery of major storm costs with the NJBPU. On February 24, 2014, a Stipulation was filed with the NJBPU by JCP&L, the Division of Rate Counsel and NJBPU Staff which will allow recovery of $736 million of JCP&L's $744 million of costs related to the significant weather events of 2011 and 2012. As a result, FirstEnergy recorded a regulatory asset impairment charge of approximately $8 million (pre-tax) as of December 31, 2013. By its Order of March 19, 2014, the NJBPU approved the Stipulation of Settlement. Although the settlement permits recovery of 2011 and 2012 storm costs, the recovery of the 2011 costs will be addressed in the pending base rate case; whereas the manner and timing of recovery of the 2012 storm costs totaling $580 million will be determined by the NJBPU.

OHIO

The Ohio Companies primarily operate under their ESP 3 plan which expires on May 31, 2016. The material terms of ESP 3 include:

- Continuing the current base distribution rate freeze through May 31, 2016;
- Continues collection of lost distribution revenues associated with energy efficiency and peak demand reduction programs;
- Continuing to provide economic development and assistance to low-income customers for the two-year plan period at levels established in the prior ESP;
- A 6% generation rate 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);
- Continuing to provide power to non-shopping customers at a market-based price set through an auction process;
- Continuing Rider DCR that allows continued investment in the distribution system for the benefit of customers;
- Continuing commitment not to recover from retail customers certain costs related to transmission cost allocations 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, subject to the outcome of certain FERC proceedings;
- 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, Ohio's renewable energy and energy efficiency standard, 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.

Notices of appeal of the Ohio Companies' ESP 3 plan to the Supreme Court of Ohio were filed by the Northeast Ohio Public Energy Council and the ELPC. The matter has not yet been scheduled for oral argument.

The Ohio Companies filed an application with the PUCO on August 4, 2014 seeking approval of their ESP IV entitled *Powering Ohio's Progress*. The Ohio Companies have requested a decision by the PUCO by April 8, 2015. The Ohio Companies filed a partial Stipulation and Recommendation on December 22, 2014. The evidentiary hearing on the ESP IV is scheduled to commence on April 13, 2015. The material terms of the proposed plan include:

- Continuing a base distribution rate freeze through May 31, 2019;
- Continuing collection of lost distribution revenues associated with energy efficiency and peak demand reduction programs;
- Providing economic development and assistance to low-income customers for the three-year plan period;

- An Economic Stability Program providing for a retail rate stability rider to flow through charges or credits representing the net result of the costs paid to FES through a proposed 15-year purchase power agreement for the output of Sammis, Davis-Besse and FES' share of OVEC against the revenues received from selling the output into the PJM markets over the same period;
- Continuing to provide power to non-shopping customers at a market-based price set through an auction process;
- Continuing Rider DCR with increased revenue caps of approximately $30 million per year that allows continued investment supporting the distribution system for the benefit of customers;
- A commitment not to recover from retail customers certain costs related to transmission cost allocations for the longer of the five-year period from June 1, 2011 through May 31, 2016 or when the amount of such costs avoided by customers for certain types of products totals $360 million, including appropriately such costs from MISO along with such costs from PJM, subject to the outcome of certain FERC proceedings; and
- General updates to electric service regulations and tariffs to reflect regulatory orders, administrative rule changes, and current practices.

Under Ohio's energy efficiency standards (SB221 and SB310), and the Ohio Companies' filing of amended energy efficiency plans, the Ohio Companies are required to implement energy efficiency programs that achieve a total annual energy savings equivalent of approximately 2,237 GWHs in 2014, 2015 and 2016. The Ohio Companies are also required to reduce peak demand in 2009 by 1%, with an additional 0.75% reduction each year thereafter through 2014, and retain the 2014 level for 2015 and 2016, and then increase the benchmark by an additional 0.75% thereafter through 2020.

On March 20, 2013, the PUCO approved the three-year energy efficiency portfolio plans for 2013-2015, estimated to cost the Ohio Companies approximately $250 million over the three-year period, which is expected to be recovered in rates. Applications for rehearing were filed by the Ohio Companies and several other parties. On July 17, 2013, the PUCO denied the Ohio Companies' application for rehearing, in part, but authorized the Ohio Companies to receive 20% of any revenues obtained from offering energy efficiency and DR reserves into the PJM auction. The PUCO also confirmed that the Ohio Companies can recover PJM costs and applicable penalties associated with PJM auctions, including the costs of purchasing replacement capacity from PJM incremental auctions, to the extent that such costs or penalties are prudently incurred. On August 16, 2013, ELPC and OCC filed applications for rehearing, which were granted for the sole purpose of further consideration of the issue. On September 24, 2014, the Ohio Companies filed an amendment to their portfolio plan as contemplated by SB310, seeking to suspend certain programs for the 2015-2016 period in order to better align the plan with the new benchmarks under SB310. On November 20, 2014, the PUCO approved the Ohio Companies' amended portfolio plan. Several applications for rehearing were filed, and the PUCO granted those applications for further consideration of the matters specified in those applications.

On September 16, 2013, the Ohio Companies filed with the Supreme Court of Ohio a notice of appeal of the PUCO's July 17, 2013 Entry on Rehearing related to energy efficiency, alternative energy, and long-term forecast rules stating that the rules issued by the PUCO are inconsistent with, and are not supported by, statutory authority. On October 23, 2013, the PUCO filed a motion to dismiss the appeal, which is still pending. The matter has not been scheduled for oral argument.

Ohio law requires electric utilities and electric service companies in Ohio to serve part of their load from renewable energy resources measured by an annually increasing percentage amount through 2024, except 2015 and 2016 that remain at the 2014 level. The Ohio Companies conducted RFPs in 2009, 2010 and 2011 to secure RECs to help meet these renewable energy requirements. In September 2011, the PUCO opened a docket to review the Ohio Companies' alternative energy recovery rider through which the Ohio Companies recover the costs of acquiring these RECs. The PUCO issued an Opinion and Order on August 7, 2013 approving the Ohio Companies' acquisition process and their purchases of RECs to meet statutory mandates in all instances except for part of the purchases arising from one auction and directing the Ohio Companies to credit non-shopping customers in the amount of $43.4 million, plus interest, on the basis that the Ohio Companies did not prove such purchases were prudent. Based on the PUCO ruling, a regulatory charge of approximately $51 million, including interest, was recorded in the fourth quarter of 2013. On December 24, 2013, following the denial of their application for rehearing, the Ohio Companies filed a notice of appeal and a motion for stay of the PUCO's order with the Supreme Court of Ohio, which was granted. On February 18, 2014, the OCC and the ELPC also filed appeals of the PUCO's order. The Ohio Companies filed their merit brief with the Supreme Court of Ohio on March 6, 2014 and the briefing process concluded on December 24, 2014. The matter is not yet scheduled for oral argument.

On April 9, 2014, the PUCO initiated a generic investigation of marketing practices in the competitive retail electric service market, with a focus on the marketing of fixed-price or guaranteed percent-off SSO rate contracts where there is a provision that permits the pass-through of new or additional charges.

PENNSYLVANIA

The Pennsylvania Companies currently operate under DSPs that expire on May 31, 2015, 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 July 24, 2014, the PPUC unanimously approved a settlement of the Pennsylvania Companies' DSPs for the period of June 1, 2015 through May 31, 2017, that provides for quarterly descending clock auctions to procure 3, 12 and 24-month energy contracts, as well as one RFP seeking 2-year contracts to secure SRECs for ME, PN and Penn.

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 refunded those amounts to customers over 29-months concluding in the second quarter of 2013. On appeal, the Commonwealth Court affirmed 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. The Pennsylvania Supreme Court denied ME's and PN's Petition for Allowance of Appeal and the Supreme Court of the United States denied ME's and PN's Petition for Writ of Certiorari. The U.S. District Court for the Eastern District of Pennsylvania granted the PPUC's motion to dismiss the complaint filed by ME and PN to obtain 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. As a result of the U.S. District Court's decision, FirstEnergy recorded a regulatory asset impairment charge of approximately $254 million (pre-tax) in the quarter ended September 30, 2013. On appeal, on September 16, 2014, in a split decision, two judges of a three-judge panel of the United States Court of Appeals for the Third Circuit affirmed the U.S. District Court's dismissal of the complaint, agreeing that ME and PN had litigated the issue in the state proceedings and thus were precluded from subsequent litigation in federal court. On September 30, 2014, ME and PN filed for rehearing and rehearing en banc before the Third Circuit and, on October 15, 2014, the Third Circuit rejected that rehearing request. ME and PN filed a Petition for Certiorari with the U.S. Supreme Court on February 12, 2015.

Pursuant to Pennsylvania's EE&C legislation (Act 129 of 2008), 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 directed all of the electric utilities in Pennsylvania to submit by November 15, 2012, a Phase II EE&C Plan that would be in effect for the period June 1, 2013 through May 31, 2016. The PPUC deferred ruling on the need to create peak demand reduction targets and did not include a peak demand reduction requirement in the Phase II plans. On March 14, 2013, the PPUC adopted a settlement among the Pennsylvania Companies and interested parties and approved the Pennsylvania Companies' Phase II EE&C Plans for the period 2013-2016. Total costs of these plans are expected to be approximately $234 million and recoverable through the Pennsylvania Companies' reconcilable EE&C riders.

On August 4, 2014, the Pennsylvania Companies each filed tariffs with the PPUC proposing general rate increases associated with their distribution operations. The filings request approval to increase operating revenues by approximately $151.9 million at ME, $119.8 million at PN, $28.5 million at Penn, and $115.5 million at WP based upon fully projected future test years for the twelve months ending April 30, 2016 at each of the Pennsylvania Companies. On February 3, 2015, each of the Pennsylvania Companies filed a Joint Petition for Settlement seeking PPUC approval of the agreements reached in each proceeding which included, among other things: 1) increases in current distribution revenues of $89.3 million for ME, $90.8 million for PN, $15.9 million for Penn and $96.8 million for WP; 2) a Universal Services Charge Rider to be established for WP; 3) storm reserve accounts for future storm recovery to be established for each of the Pennsylvania Companies; and 4) certain other operational and customer service-related provisions. The sole issue reserved for briefing was with respect to the scope and pricing of the Companies' proposed LED offerings. Orders on the proposed increases are expected in May 2015.

WEST VIRGINIA

On April 30, 2014, MP and PE filed a rate case, as amended on June 13, 2014, requesting a base rate increase of approximately $104 million, or 9.9%, based on an historic 2013 test year. The filing also included a request for an additional $48 million to recover by surcharge costs for new and existing vegetation management programs. On November 3, 2014, a Joint Stipulation was submitted by all parties which settled all issues in the proceeding. The settlement includes, among other things: a $15 million increase in base rate revenues effective February 25, 2015; the implementation of a Vegetation Management Surcharge effective February 25, 2015 to recover all costs related to both new and existing vegetation maintenance programs; authority to establish a regulatory asset for MATS investments placed into service in 2016 and 2017; authority to defer, amortize and recover over a 5-year period approximately $46 million of storm restoration costs; and elimination of the Temporary Transaction Surcharge for costs associated with MP's acquisition of the Harrison plant in October

2013 and movement of those costs into base rates effective February 25, 2015. On February 3, 2015, the WVPSC approved the settlement in full and without modification. MP and PE's new rates will go into effect February 25, 2015.

On August 29, 2014, MP and PE filed their annual ENEC case proposing an approximate $65.8 million annual increase in ENEC rates, which is a 5.7% overall increase to existing rates. The increase is comprised of an actual $51.6 million under-recovered balance as of June 30, 2014, and a projected $14.2 million in under-recovery for the 2015 rate effective period. A settlement was reached by all the parties, which was filed with the WVPSC on December 2, 2014. The parties agreed to defer $16.8 million of the energy portion of the under-recovery balance for medium and large customers for one year at a carrying cost of 4% in order to mitigate the proposed rate impact to those customers. The settlement permits MP and PE to recover all of their costs incurred during the two year review period and closes the review period except for two coal issues for further review in next year's ENEC case. On January 29, 2015, the WVPSC approved the settlement in full without modification and new ENEC rates will go into effect February 25, 2015.

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, NG, 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 occurrences are found, FirstEnergy develops information about the occurrence and develops a remedial response to the specific circumstances, including in appropriate cases "self-reporting" an occurrence to RFC. Moreover, it is clear that NERC, RFC and FERC will continue to refine existing reliability standards as well as to develop and adopt new reliability standards. Any inability on FirstEnergy's part to comply with the reliability standards for its bulk electric 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 Rates

PJM and its stakeholders have been debating the proper method to allocate costs for new transmission facilities. While FirstEnergy and other parties advocate for a traditional "beneficiary pays" (or usage based) approach, others advocate for "socializing" the costs on a load-ratio share basis, where each customer in the zone would pay based on its total usage of energy within PJM. This question has been the subject of extensive litigation before FERC and the appellate courts, including most recently before the Seventh Circuit. On June 25, 2014, a divided three-judge panel of the Seventh Circuit ruled that FERC had not quantified the benefits that western PJM utilities would derive from certain new 500 kV or higher lines and thus had not adequately supported its decision to socialize the costs of these lines. The majority found that eastern PJM utilities are the primary beneficiaries of the lines, while western PJM utilities are only incidental beneficiaries, and that, while incidental beneficiaries should pay some share of the costs of the lines, that share should be proportionate to the benefit they derive from the lines, and not on load-ratio share in PJM as a whole. The court remanded the case to FERC, which issued an order setting the issue of cost allocation for hearing and settlement proceedings. Settlement discussions under a FERC-appointed settlement judge are ongoing.

Order No. 1000, issued by FERC on July 21, 2011, announced new policies regarding transmission planning and transmission cost allocation, requiring the submission of a compliance filing by PJM and 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. On August 15, 2014 the U.S. Court of Appeals for the D.C. Circuit affirmed Order No. 1000, including its termination of certain "right of first refusal" privileges discussed in more detail below. The court subsequently denied a request for rehearing of its decision.

In series of orders, including certain of the orders related to the Order No. 1000 proceedings, FERC has asserted that the PJM transmission owners do not hold an incumbent "right of first refusal" to construct, own and operate transmission projects within their respective footprints that are approved as part of PJM's RTEP process. FirstEnergy and other PJM transmission owners have appealed these rulings, and those appeals are pending before the U.S. Court of Appeals for the D.C. Circuit.

To demonstrate compliance with the regional cost allocation principles of Order No. 1000, the PJM transmission owners, including FirstEnergy, proposed a hybrid allocation of 50% beneficiary pays and 50% socialized to be effective for RTEP projects approved by the PJM Board of Managers on, and after, the requested February 1, 2013 effective date of the compliance filing. FERC has accepted that approach.

Separately, the PJM transmission owners, including FirstEnergy, submitted filings to FERC setting forth the cost allocation method for projects that cross the borders between the PJM Region and: (1) the NYISO region; (2) the MISO region; and (3) the FERC-jurisdictional members of the SERTP region. These filings propose to allocate the cost of these interregional transmission projects based on the costs of projects that otherwise would have been constructed separately in each region, or, in the case of MISO, indicate that the cost allocation provisions for interregional transmission projects provided in the Joint Operating Agreement between PJM and MISO comply with the requirements of Order No. 1000. FERC accepted the PJM/MISO and PJM/SERTP filing, subject to refund and further compliance requirements. The PJM/NYISO cross-border project cost allocation filing remains pending before FERC.

The outcome of these proceedings and their impact, if any, on FirstEnergy cannot be predicted at this time.

RTO Realignment

On June 1, 2011, ATSI and the ATSI zone transferred from MISO to PJM. While many of the matters involved with the move have been resolved, FERC denied recovery under ATSI's transmission rate for certain charges that collectively can be described as "exit fees" and certain other transmission cost allocation charges totaling approximately $78.8 million until such time as ATSI submits a cost/benefit analysis demonstrating net benefits to customers from the move. FERC rejected a proposed settlement agreement to resolve the exit fee and transmission cost allocation issues, stating that its action is without prejudice to ATSI submitting a cost/benefit analysis demonstrating that the benefits of the RTO realignment decisions outweigh the exit fee and transmission cost allocation charges. FirstEnergy's request for rehearing of FERC's order remains pending.

Separately, the question of ATSI's responsibility for certain costs for the "Michigan Thumb" transmission project continues to be disputed. Potential responsibility arises under the MISO MVP tariff, which has been litigated in complex proceedings before FERC and certain U.S. appellate courts. In the event of a final non-appealable order that rules that ATSI must pay these charges, ATSI will seek recovery of these charges through its formula rate. On a related issue, FirstEnergy joined certain other PJM transmission owners in a protest of MISO's proposal to allocate MVP costs to energy transactions that cross MISO's borders into the PJM Region. On January 22, 2015, FERC issued an order establishing a paper hearing on remand from the Seventh Circuit of the issue of whether any limitation on "export pricing" for sales of energy from MISO into PJM is justified in light of applicable FERC precedent. Initial comments on the MISO/PJM MVP issue are due March 9, 2015, and reply comments are due April 8, 2015.

In addition, in a May 31, 2011 order, FERC ruled that the costs for certain "legacy RTEP" transmission projects in PJM approved before ATSI joined PJM could be charged to transmission customers in the ATSI zone. The amount to be paid, and the question of derived benefits, is pending before FERC as a result of the Seventh Circuit's June 25, 2014 order described above under PJM Transmission Rates.

The outcome of those proceedings that address the remaining open issues related to ATSI's move into PJM cannot be predicted at this time.

2014 ATSI Formula Rate Filing

On October 31, 2014, ATSI filed a proposal with FERC to change the structure of its formula rate. The proposed change requested to move from an "historical looking" approach, where transmission rates reflect actual costs for the prior year, to a "forward looking" approach, where transmission rates would be based on the estimated costs for the coming year, with an annual true up. Several parties protested ATSI's filing. On December 31, 2014, FERC issued an order accepting ATSI's filing effective January 1, 2015, as requested, subject to refund and the outcome of hearing and settlement proceedings. Settlement discussions under a FERC-appointed settlement judge are ongoing. FERC also initiated an inquiry pursuant to Section 206 of the FPA into ATSI's ROE and certain other matters, with a refund effective date of January 12, 2015, for any refund resulting from the inquiry. A procedural schedule for the Section 206 inquiry has not yet been established.

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 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. The California Parties appealed FERC's decision back to the Ninth Circuit, where the appeal remains pending. AE Supply joined with other intervenors in the case and filed a brief in support of FERC's dismissal of the case. Oral argument was held on February 11, 2015. The matter is now before the Ninth Circuit for decision.

In another proceeding, in June 2009, the California Attorney General, on behalf of certain California parties, filed a 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 FERC granted. The California Attorney General 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

On August 24, 2012, the PJM Board of Managers canceled the PATH project, a proposed transmission line from West Virginia through Virginia and into Maryland which PJM had previously suspended in February 2011. As a result of PJM canceling the project, approximately $62 million and approximately $59 million in costs incurred by PATH-Allegheny and PATH-WV (an equity method investment for FE), respectively, were reclassified from net property, plant and equipment to a regulatory asset for future recovery. PATH-Allegheny and PATH-WV requested authorization from FERC to recover the costs with a proposed ROE of 10.9% (10.4% base plus 0.5% for RTO membership) from PJM customers over five years. FERC issued an order denying the 0.5% ROE 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 proceedings and hearing if the parties do not agree to a settlement. On March 24, 2014, the FERC Chief ALJ terminated settlement judge procedures and appointed an ALJ to preside over the hearing phase of the case. The FERC Chief ALJ later extended the procedural schedule to allow time for the parties to address the applicability of FERC's Opinion No. 531 to the PATH proceedings. FERC's Opinion No. 531, as discussed below, revises FERC's methodology for calculating ROE. The hearing is scheduled to commence in March 2015.

MISO Capacity Portability

On June 11, 2012, in response to certain arguments advanced by MISO, 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. FirstEnergy and other parties have submitted filings arguing that MISO's concerns largely are without foundation and suggested that FERC address the remaining concerns in the existing stakeholder process that is described in the PJM/MISO Joint Operating Agreement. FERC has not mandated a solution, and the RTOs and affected parties are working to address the MISO's proposal in stakeholder proceedings. In January 2015, the RTOs and affected parties indicated to FERC that discussions on the various issues are continuing. 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.

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. FE also performs bilateral transactions for the purpose of hedging the price differences between the location of supply resources and retail load obligations. 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 2010, FES and AE Supply have lost more than $94 million in revenues that they otherwise would have received as FTR holders to hedge congestion costs. FES and AE Supply expect to continue to experience significant underfunding.

On February 15, 2013, FES and AE Supply filed a renewed complaint with FERC for the purpose of changing the PJM Tariff to eliminate FTR underfunding. On June 5, 2013, FERC issued its order denying the new complaint. Requests for rehearing, and all subsequent filings in the docket, are pending before FERC. The PJM stakeholders continue to discuss FTR underfunding.

A recent and related issue is the effect that certain financial trades have on congestion. On August 29, 2014, FERC instituted an investigation to address the question of whether the current rules regarding "Up-to Congestion" transactions are just and reasonable. FESC, on behalf of FES and the Utilities, filed comments supporting the investigation, arguing that PJM Tariff changes would decrease the incidence of Up-to Congestion transactions, and funding for FTRs likely would increase. FERC convened a technical conference on January 7, 2015 to discuss application of certain FTR-related rules to Up-to Congestion and virtual transactions and whether PJM's current uplift allocation for Up-to Congestion and virtual transactions is just and reasonable. FERC action following the technical conference is pending.

PJM Market Reform: 2014 PJM RPM Tariff Amendments

In late 2013 and early 2014, PJM submitted a series of amendments to the PJM Tariff to ensure that resources that clear in the RPM auctions are available as physical resources in the delivery year and that the rules implement comparable obligations for different types of resources. PJM's filings can be grouped into four categories: (i) DR; (ii) imports; (iii) modeling of transmission upgrades in calculating geographic clearing prices; and (iv) arbitrage/capacity replacement. In each of the relevant dockets, FirstEnergy and other parties submitted comments largely supporting PJM's proposed amendments. FERC largely approved the PJM Tariff amendments as proposed by PJM regarding DR, imports, and transmission upgrade modeling. Compliance filings pursuant to and requests for rehearing of certain of these orders are pending before FERC. However, FERC rejected the arbitrage/capacity replacement amendments, directing instead that a technical conference be convened to further examine the issues. The technical conference has yet to be scheduled.

PJM Market Reform: PJM Capacity Performance Proposal and 2015/2016 Reliability Filings

On December 12, 2014, PJM submitted two filings to implement its proposed "Capacity Performance" reform of the RPM capacity market. PJM proposes to revise the PJM Tariff to, among other things: (i) adopt a modified version of the FERC-approved ISO New England Inc. capacity performance payment structure; (ii) allow no excuses for nonperformance except under certain defined circumstances; (iii) maintain DR as a supply-side resource; and (iv) impose a Capacity Performance Resource must-offer requirement (units that can perform as a Capacity Performance Resource must offer into the capacity market, except certain defined resources, including DR). PJM also proposes, among other things, to revise the PJM Operating Agreement to provide limits in energy market offers based on specific physical characteristics and to ensure that capacity resources are available when the PJM Region needs them to perform. PJM requested an effective date of April 1, 2015 for these proposed reforms. Numerous parties filed comments on and protests to PJM's Capacity Performance filings. FESC, on behalf of its affected affiliates, and, as part of a coalition of certain other PJM utilities, filed comments and protests on the proposed reforms. PJM's filings and all related pleadings are pending before FERC.

In addition, on December 24, 2014, PJM submitted two filings seeking to ensure enough capacity is available during the 2015/2016 Delivery Year. First, PJM proposed to revise the PJM Tariff to allow PJM to procure an undetermined amount of additional capacity for the 2015/2016 Delivery Year to address reliability concerns. PJM requested an effective date of February 23, 2015 for this revision. Second, PJM requested a one-time PJM Tariff waiver that would permit PJM to keep approximately 2,000 MW of committed capacity that should be released for the third incremental auction for the 2015/2016 Delivery Year. Without the waiver, PJM would be required under the PJM Tariff to release this capacity. PJM requests an effective date of February 23, 2015 for the waiver. Numerous parties filed comments on and protests to these PJM filings. FESC, on behalf of its affected affiliates, and, as part of a coalition of certain other PJM utilities, filed comments in support of both PJM filings and seeking additional information from PJM about the scope of any capacity shortfall. PJM's filings and all related pleadings are pending before FERC.

PJM Market Reform: PJM RPM Auctions - Calculation of Unit-Specific Offer Caps

The PJM Tariff describes the rules for calculating the "offer cap" for each unit that offers into the RPM auctions. FES disagreed with the PJM Market Monitor's approach for calculating the offer caps and in 2014, FES asked FERC to determine which PJM Tariff interpretation, FES's or the PJM Market Monitor's, was correct. On August 25, 2014, FERC issued a declaratory order agreeing with the FES interpretation of the PJM Tariff language. FERC went on, however, to initiate a new proceeding to examine whether the existing PJM Tariff language is just and reasonable. PJM filed its brief explaining why the existing PJM Tariff language is just and reasonable. Other parties, including FES, submitted responsive briefs. The briefs and related pleadings are pending before FERC.

PJM Market Reform: FERC Order No. 745 - DR

On May 23, 2014, a divided three-judge panel of the U.S. Court of Appeals for the D.C. Circuit issued an opinion vacating FERC Order No. 745, which required that, under certain parameters, DR participating in organized wholesale energy markets be compensated at LMP. The majority concluded that DR is a retail service, and therefore falls under state, and not federal, jurisdiction, and that FERC, therefore, lacks jurisdiction to regulate DR. The majority also found that even if FERC had jurisdiction over DR, Order No. 745 would be arbitrary and capricious because, under its requirements, DR was inappropriately receiving a double payment (LMP plus the savings of foregone energy purchases). On January 15, 2015, FERC and a coalition of DR providers and industrial end-user groups filed separate petitions for U.S. Supreme Court review of the May 23, 2014 decision. Responses to those petitions are due March 19, 2015. The U.S. Court of Appeals for the D.C. Circuit will withhold issuance of the mandate pending the United States Supreme Court's disposition of those petitions.

On May 23, 2014, FESC, on behalf of its affiliates with market-based rate authorization, filed a complaint asking FERC to issue an order requiring the removal of all portions of the PJM Tariff allowing or requiring DR to be included in the PJM capacity market, with a refund effective date of May 23, 2014. FESC also requested that the results of the May 2014 PJM BRA be considered void and legally invalid to the extent that DR cleared that auction because the participation of DR in that auction was unlawful in light of the May 23, 2014 U.S. Court of Appeals for the D.C. Circuit decision discussed above. FESC, on behalf of FES, subsequently filed an amended complaint renewing its request that DR be removed from the May 2014 BRA. Specifically, FESC requested that FERC direct PJM to recalculate the results of the May 2014 BRA by: (i) removing DR from the PJM capacity supply pool; (ii) leaving the offers of actual capacity suppliers unchanged; and then (iii) determining which capacity suppliers clear the auction on the basis of the offers they submitted consistent with the existing PJM Tariff once the unlawful DR resources have been removed. The complaint remains pending before FERC. The timing of FERC action and the outcome of this proceeding cannot be predicted at this time.

On January 14, 2015, PJM filed proposed amendments to the PJM Tariff for the purpose of addressing the uncertainty of DR. The amendments, which will become effective only in certain defined conditions, purport to be in response to the U.S. Court of Appeals for the D.C. Circuit's May 23, 2014 decision regarding FERC's jurisdiction to regulate DR, as discussed above. If implemented, the amendments will move DR from the supply side to the load side for purposes of PJM's RPM capacity markets, and will permit loads to bid load reductions into the RPM auctions occurring after April 1, 2015. On February 13, 2015, FirstEnergy, as part of a coalition, filed a protest against PJM's proposed amendments. FirstEnergy expects further filings before FERC rules on this matter.

PJM Market Reform: PJM 2014 Triennial RPM Review

The PJM Tariff obligates PJM to perform a thorough review of its RPM program every three years. On September 25, 2014, PJM filed proposed changes to the PJM Tariff as part of the latest review cycle. Among other adjustments, the filing included: (i) shifting the VRR curve one percentage point to the right, which would increase the amount of capacity supply that is procured in the RPM auctions and the clearing price; and (ii) a change to the index used for calculating the generation plant construction costs of the

Net CONE formula for the future years between triennial reviews. On November 28, 2014, FERC accepted the PJM Tariff amendments as proposed, subject to a minor compliance requirement. PJM subsequently submitted the required compliance filing. On December 23, 2014, a coalition including FESC, on behalf of its affected affiliates, requested rehearing of FERC's order. PJM's compliance filing, and the coalition's and others' requests for rehearing, remain pending before FERC.

Market-Based Rate Authority, Triennial Update

The Utilities, AE Supply, FES, FG, NG, FirstEnergy Generation Mansfield Unit 1 Corp., Buchanan Generation, LLC, and Green Valley Hydro, LLC each hold authority from FERC to sell electricity at market-based rates. One condition for retaining this authority is that every three years each entity must file an update with the FERC that demonstrates that each entity continues to meet FERC's requirements for holding market-based rate authority. On December 20, 2013, FESC, on behalf of its affiliates with market-based rate authority, submitted to FERC the most recent triennial market power analysis filing for each market-based rate holder for the current cycle of this filing requirement. On August 13, 2014, FERC accepted the triennial filing as submitted.

FERC Opinion No. 531

On June 19, 2014, FERC issued Opinion No. 531, in which FERC revised its approach for calculating the discounted cash flow element of FERC's ROE methodology, and announced a qualitative adjustment to the ROE methodology results. Under the old methodology, FERC used a five-year forecast for the dividend growth variable, whereas going forward the growth variable will consist of two parts: (a) a five-year forecast for dividend growth (2/3 weight); and (b) a long-term dividend growth based on a forecast for the U.S. economy (1/3 weight). Regarding the qualitative adjustment, FERC formerly pegged ROE at the mid-point of the "zone of reasonableness" that came out of the ROE formula, whereas going forward, FERC may rely on record evidence to make qualitative adjustments to the outcome of the ROE methodology in order to reach a level sufficient to attract future investment. Requests for rehearing of Opinion No. 531 are currently pending before FERC. On October 16, 2014, FERC issued its Opinion No. 531-A, applying the revised ROE methodology to certain ISO New England Inc. transmission owners. FirstEnergy is evaluating the potential impact of Opinion No. 531 on the authorized ROE of our FERC-regulated transmission utilities and the cost-of-service wholesale power generation transactions of MP.

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.

Clean Air Act

FirstEnergy complies with SO_2 and NOx emission 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. 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 D.C. Circuit decided that CAIR violated the CAA but allowed CAIR to remain in effect to "temporarily preserve its environmental values" until the EPA replaced 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 D.C. Circuit and was ultimately vacated by the Court on August 21, 2012. The Court subsequently ordered the EPA to continue administration of CAIR until it finalized a valid replacement for CAIR. On April 29, 2014, the U.S. Supreme Court reversed the U.S. Court of Appeals for the D.C. Circuit decision vacating CSAPR and generally upheld the EPA's authority under the CAA to establish the regulatory structure underpinning CSAPR. On October 23, 2014, the U.S. Court of Appeals for the D.C. Circuit lifted its stay of CSAPR allowing its Phase 1 reductions of NOx and SO_2 emissions to begin in 2015, a three year delay from EPA's original rule. CSAPR Phase 2 will also be delayed by three years to 2017. Depending on the outcome of further proceedings in this matter and how the EPA and the states implement the final rules, the future cost of compliance may be substantial and changes to FirstEnergy's and FES' operations may result.

MATS imposes 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 extension through April 16, 2016 for MATS compliance at the Fort Martin, Harrison and Pleasants stations. On March 20, 2013, the PA DEP granted an extension through April 16, 2016 for MATS compliance at the Hatfield's Ferry and Bruce Mansfield stations. In December 2014, FG requested an extension through April 16, 2016 for MATS compliance at the Bay Shore and Sammis stations and await a decision from OEPA. 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 was challenged in the U.S. Court of Appeals for the D.C. Circuit by various entities, including FirstEnergy's challenge of the PM emission limit imposed on petroleum coke boilers, such as Bay Shore Unit 1. On April 15, 2014, MATS was upheld by the U.S. Court of Appeals for the D.C. Circuit, however, the Court refused to decide FirstEnergy's challenge of the PM emission limit imposed on petroleum coke boilers due to a January 2013 petition for reconsideration still pending but not addressed by EPA. On November 25, 2014, the U.S. Supreme Court agreed to review MATS, specifically, to determine if EPA should have evaluated the cost of MATS prior to regulating. Depending on the outcome of the U.S. Supreme Court review and how the MATS are ultimately implemented, FirstEnergy's total capital cost for compliance (over the 2012 to 2018 time period) is currently expected to be approximately $370 million (CES segment of $178 million and Regulated Distribution segment of $192 million), of which $133 million has been spent through 2014 ($56 million at CES and $77 million at Regulated Distribution).

As of September 1, 2012, Albright, Armstrong, Bay Shore Units 2-4, Eastlake Units 4-5, R. Paul Smith, Rivesville and Willow Island were deactivated. FG entered into RMR arrangements with PJM for Eastlake Units 1-3, Ashtabula Unit 5 and Lake Shore Unit 18 through the spring of 2015, when they are scheduled to be deactivated. In February 2014, PJM notified FG that Eastlake Units 1-3 and Lake Shore Unit 18 will be released from RMR status as of September 15, 2014. FG intends to operate the plants through April 2015, subject to market conditions. As of October 9, 2013, the Hatfield's Ferry and Mitchell stations were also deactivated.

FirstEnergy and FES have various long-term coal supply and transportation agreements, some of which run through 2025 and certain of which are related to the plants described above. FE and FES have asserted force majeure defenses for delivery shortfalls under certain agreements, and are in discussion with the applicable counterparties. As to coal transportation agreements, FE and FES have agreed to pay liquidated damages for delivery shortfalls for 2014 in the estimated amount of $70 million. If FE and FES fail to reach a resolution with the applicable counterparties for the agreements associated with the deactivated plants or unresolved aspects of the agreements and it were ultimately determined that, contrary to their belief, the force majeure provisions or other defenses, do not excuse or otherwise mitigate the delivery shortfalls, the results of operations and financial condition of both FirstEnergy and FES could be materially adversely impacted. If that were to occur, FE and FES are unable to estimate the loss or range of loss. Additionally, on July 1, 2014, FES terminated a long-term fuel supply agreement. In connection with this termination, FES recognized a pre-tax charge of $67 million in the second quarter of 2014. In one coal supply agreement, AE Supply has asserted termination rights effective in 2015. In response to the notification of the termination, the coal supplier has commenced litigation alleging AE Supply does not have sufficient justification to terminate the agreement. There are 6 million tons remaining under the contract for delivery. At this time, FirstEnergy cannot estimate the loss or range of loss regarding the on-going litigation with respect to this agreement.

In June 2005, the PA DEP and the Attorneys General of New York, New Jersey, Connecticut and Maryland filed suit against AE, AE Supply, MP, PE and WP in the U.S. District Court for the Western District of Pennsylvania alleging, among other things, that AE performed major modifications in violation of the NSR provisions of the CAA and the Pennsylvania Air Pollution Control Act at the coal-fired Hatfield's Ferry, Armstrong and Mitchell Plants in Pennsylvania. On February 6, 2014, the Court entered judgment for AE, AE Supply, MP, PE and WP finding they had not violated the CAA or the Pennsylvania Air Pollution Control Act. New York, Connecticut, and Maryland withdrew their appeal to the U.S. Court of Appeals for the Third Circuit on December 15, 2014, concluding this litigation. This decision does not change the status of these plants which remain deactivated.

In September 2007, AE received an 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. The EPA's NOV alleges equipment replacements during maintenance outages triggered the pre-construction permitting requirements under the NSR and PSD programs. On June 29, 2012, January 31, 2013, and March 27, 2013, EPA issued 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. On December 12, 2014, EPA issued a CAA section 114 request for the Fort Martin coal-fired plant seeking information and documentation relevant to its operation and maintenance, including capital projects undertaken since 2009. FirstEnergy 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 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.

Climate Change

There are a number of initiatives to reduce GHG emissions at the state, federal and international level. Certain northeastern states are participating in the RGGI and western states led by California, have implemented programs, primarily cap and trade mechanisms, to control emissions of certain GHGs. Additional policies reducing GHG emissions, such as demand reduction programs, renewable portfolio standards and renewable subsidies have been implemented across the nation. A June 2013, Presidential Climate Action Plan outlined goals to: (1) cut carbon pollution in America by 17% by 2020 (from 2005 levels); (2) prepare the United States for the impacts of climate change; and (3) lead international efforts to combat global climate change and prepare for its impacts. GHG emissions have already been reduced by 10% between 2005 and 2012 according to an April, 2014 EPA Report. In a joint announcement on November 12, 2014, President Obama stated a U.S. target of reducing GHG emissions by 26 to 28% by 2025 from 2005 emission levels and China's President stated its GHG emissions will "peak", around 2030 with approximately 20% of its energy generated by non-fossil fuels by that same year. Due to plant deactivations and increased efficiencies, FirstEnergy anticipates its CO_2 emissions will be reduced 25% below 2005 levels by 2015, exceeding the President's Climate Action Plan goals both in terms of timing and reduction levels.

EPA released its final "Endangerment and Cause or Contribute Findings for Greenhouse Gases under the Clean Air Act" in December 2009, concluding that concentrations of several key GHGs constitutes an "endangerment" and may be regulated as "air pollutants" under the CAA and mandated measurement and reporting of GHG emissions from certain sources, including electric generating plants. EPA proposed a new source performance standard in September 2013, which would not apply to any existing, modified, or reconstructed fossil fuel generating units, of 1,000 lbs. CO_2/MWH for large natural gas fired units (> 850 mmBTU/hr), and 1,100 lbs. CO_2/MWH for other natural gas fired units (≤ 850 mmBTU/hr), and 1,100 lbs. CO_2/MWH for fossil fuel fired units which would require partial carbon capture and storage. EPA proposed regulations in June 2014, to reduce CO_2 emissions from existing fossil fuel electric generating units that would require each state to develop state implementation plans by June 30, 2016, to meet EPA's state specific CO_2 emission rate goals. EPA's proposal allows states to request a 1-year extension for single-SIPs (June 30, 2017) or a 2-year extension for multi-state SIPs (June 30, 2018). EPA also proposed separate regulations imposing additional CO_2 emission limits on modified and reconstructed fossil fuel electric generating units. On January 7, 2015, EPA announced it would complete all of these so-called "Carbon Pollution Standards" by "midsummer" 2015. On June 23, 2014, the U.S. Supreme Court decided that CO_2 or other GHG emissions alone cannot trigger permitting requirements under the CAA, but that air emission sources that need PSD permits due to other regulated air pollutants can be required by EPA to install GHG control technologies. On November 13, 2014, the U.S. Court of Appeals for the D.C. Circuit scheduled expedited briefing to consider challenges to prevent EPA from regulating CO_2 emissions from existing fossil fuel electric generating units. Depending on the outcome of appeals and how any final rules are ultimately implemented, the future cost of compliance may be substantial.

At the international level, the United Nations Framework Convention on Climate Change resulted in the Kyoto Protocol requiring participating countries, which does not include the U.S., to reduce GHGs commencing in 2008 and has been extended through 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.

The EPA finalized CWA Section 316(b) regulations in May 2014, requiring cooling water intake structures with an intake velocity greater than 0.5 feet per second to reduce fish impingement when aquatic organisms are pinned against screens or other parts of a cooling water intake system to a 12% annual average and requiring cooling water intake structures exceeding 125 million gallons per day to conduct studies to determine site-specific controls, if any, to reduce entrainment, which occurs when aquatic life is drawn into a facility's cooling water system. 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 cooling water intake channel to divert fish away from the plant's cooling water intake system. Depending on the results of such studies and any final action taken by the states based on those studies, the future costs of compliance with these standards may require material capital expenditures.

The EPA proposed updates to the waste water effluent limitations guidelines and standards for the Steam Electric Power Generating category (40 CFR Part 423) in April 2013. The EPA proposed eight treatment options for waste water discharges from electric power plants, of which four are "preferred" by the agency. The preferred options range from more stringent chemical and biological treatment requirements to zero discharge requirements. The EPA is required to finalize this rulemaking by September 30, 2015, under a consent decree entered by a U.S. District Court and the treatment obligations are proposed to phase-in as permits are renewed on a 5-year cycle from 2017 to 2022. Depending on the content of the EPA's final rule and any final action taken by the states, the future costs of compliance with these standards may require material capital expenditures.

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 ranging from $150 million to $300 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 recommended a sulfate impairment designation for an approximately 68 mile stretch of the Monongahela River north of the West Virginia border which EPA approved in May of 2011. PA DEP subsequently recommended that the sulfate impairment designation for the Monongahela River be removed in its bi-annual water report. The EPA approved the removal of the sulfate impairment designation for the Monongahela River on December 19, 2014.

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 RCRA, as amended, and the Toxic Substances Control Act. Certain coal 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 2014, the EPA finalized regulations for the disposal of CCRs (non-hazardous), establishing national standards regarding landfill design, structural integrity design and assessment criteria for surface impoundments, groundwater monitoring and protection procedures and other operational and reporting procedures to assure the safe disposal of CCRs from electric generating plants. Depending on how the final rules are ultimately implemented, the future costs of compliance with such CCR regulations may require material capital expenditures.

The PA DEP filed a 2012 complaint against FG in the U.S. District Court for the Western District of Pennsylvania with claims under the RCRA and Pennsylvania's Solid Waste Management Act regarding the LBR CCR Impoundment and simultaneously proposed a consent decree between PA DEP and FG to resolve those claims. On December 14, 2012, a modified consent decree 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 required payment of civil penalties of $800,000 to resolve claims under the Solid Waste Management Act. PA DEP issued a 2014 permit requiring FE to provide bonding for 45 years of closure and post-closure activities and to complete closure within a 12-year period, but authorizing FE to seek a permit modification based on "unexpected site conditions that have or will slow closure progress." The permit does not require active dewatering of the CCRs, but does require a groundwater assessment for arsenic and abatement if certain conditions in the permit are met. The Bruce Mansfield Plant is pursuing several options for its CCRs following December 31, 2016. A 2013 complaint filed by Citizens Coal Counsel and other NGOs in the U.S. District Court for the Western District of Pennsylvania, against the owner and operator of a reclamation mine in LaBelle, Pennsylvania that is one possible alternative, alleged the LaBelle site is in violation of RCRA and state laws. On July 14, 2014, Citizens Coal Council served FE, FG and NRG with a citizen suit notice alleging violations of RCRA due to beneficial reuse of "coal ash" at the LaBelle Site.

On October 10, 2013 approximately 61 individuals filed a complaint against FG in the U.S. District Court for the Northern District of West Virginia seeking damages for alleged property damage, bodily injury and emotional distress related to the LBR CCR Impoundment. The complaints state claims for private nuisance, negligence, negligence per se, reckless conduct and trespass related to alleged groundwater contamination and odors emanating from the Impoundment. FG believes the claims are without merit and intends to vigorously defend itself against the allegations made in the complaints, but, at this time, is unable to predict the outcome of the above matter or estimate the possible loss or range of loss. A similar complaint involving approximately 26 individuals filed in the U.S. District Court for the Western District of Pennsylvania has been resolved and was closed on February 9, 2015, pending the filing of a stipulation for dismissal.

FirstEnergy and certain of its subsidiaries 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, 2014 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 $125 million have been accrued through December 31, 2014. Included in the total are accrued liabilities of approximately $85 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, 2014, FirstEnergy had approximately $2.3 billion invested in external trusts to be used for the decommissioning and environmental remediation of Davis-Besse, Beaver Valley, Perry and TMI-2. The values of FirstEnergy's NDTs 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 NDTs. By a letter dated July 2, 2014, FENOC submitted a $155 million FES parental guaranty relating to a shortfall in nuclear decommissioning funding for Beaver Valley Unit 1 and Perry to the NRC for approval. FE and FES have also entered into a total of $23 million in parental guaranties in support of the decommissioning of the spent fuel storage facilities located at the nuclear facilities. As required by the NRC, FirstEnergy annually recalculates and adjusts the amount of its parental guaranties, as appropriate.

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 an opportunity for a hearing on the Davis-Besse license renewal application to a group of Intervenors, subject to admissible contentions. On September 29, 2014, the Intervenors filed a petition, accompanied by a request to admit a new contention, to suspend the final licensing decision on Davis-Besse license renewal. These filings argue that the NRC's Continued Storage Rule failed to make necessary safety findings regarding the technical feasibility of spent fuel disposal and the adequacy of future repository capacity required by the Atomic Energy Act. On October 31, 2014, FENOC and the NRC Staff filed their opposition to these requests.

As part of routine inspections of the concrete shield building at Davis-Besse in 2013, FENOC identified changes to the subsurface laminar cracking condition originally discovered in 2011. These inspections revealed that the cracking condition had propagated a small amount in select areas. FENOC's analysis confirms that the building continues to maintain its structural integrity, and its ability to safely perform all of its functions. On September 2, 2014, the Intervenors in the Davis-Besse license renewal proceeding requested that the ASLB introduce issues based on FENOC's plans to manage the subsurface laminar cracking in the Davis-Besse shield building. On January 15, 2015, the ASLB denied this request. The NRC continues to evaluate FENOC's analysis of the shield building.

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.

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 for failure to supply coal required by a long term CSA. A non-jury trial was held from January 10, 2011 through February 1, 2011 regarding past and future damages incurred by AE Supply and MP as a result of the shortfall. 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 past damages/interest) and on August 25, 2011, the verdict became final. On August 26, 2011, ICG filed a Notice of Appeal with the Superior Court. On August 13, 2012, the Superior Court affirmed the $14 million past damages award against ICG but vacated the $90 million future damages award. While the Superior Court found that defendants still owed future damages, it remanded the calculation of those damages back to the trial court. Efforts by AE Supply and MP to have the Superior Court reconsider this decision or challenge it at the Pennsylvania Supreme Court were denied. In the second quarter of 2013 the final past damage award of $15.5 million (including interest) was recognized and the case was sent back to the trial court to recalculate future damages only. A multi-day damages hearing was held and, on February 13, 2015, the trial court awarded AE Supply and MP approximately $11.3 million in future damages and prejudgment interest. AE Supply and MP are evaluating the court's decision and a possible appeal. In a related proceeding before the same court, ICG appealed a ruling that prohibited their reliance on a price re-opener clause to limit future damages. On January 30, 2015, the ICG appeal was denied and ICG has moved for reconsideration on this ruling.

Other Legal Matters

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 loss or range of loss in these matters is not expected to be material to FirstEnergy or 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. See Note 1, Organization and Basis of Presentation for additional details.

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. See Note 14, Regulatory Matters for additional information.

Pension 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 pension and OPEB funding policy is based on actuarial computations using the projected unit credit method. During the year ended December 31, 2014, FirstEnergy did not make any contributions to its qualified pension plan. The underfunded status of FirstEnergy's qualified and non-qualified pension and OPEB plans as of December 31, 2014 was $3.7 billion.

FirstEnergy recognizes as a pension and OPEB mark-to-market adjustment the change in the fair value of plan assets and net actuarial gains and losses annually in the fourth quarter of each fiscal year and whenever a plan is determined to qualify for a remeasurement. The remaining components of pension and OPEB expense, primarily service costs, interest on obligations, assumed return on assets and prior service costs, are recorded on a quarterly basis. The pension and OPEB mark-to-market adjustment for the years ended December 31, 2014, 2013, and 2012 were $1,243 million ($835 million net of amounts capitalized), $(396) million ($(256) million net of amounts capitalized), and $875 million ($609 million net of amounts capitalized), respectively.

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 pension were 4.25%, 5.00% and 4.25% as of December 31, 2014, 2013 and 2012, respectively. The assumed discount rates for OPEB were 4.00%, 4.75% and 4.00% as of December 31, 2014, 2013 and 2012, 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 2014, FirstEnergy's qualified pension and OPEB plan assets earned $387 million or 6.2% compared to losses of $(22) million, or (0.3)% in 2013 and assumed a 7.75% rate of return for both years on plan assets which generated $496 million and $535 million of expected returns on plan assets, respectively. The expected return on pension 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 or whenever a plan is determined to qualify for remeasurement.

During 2014 the Society of Actuaries published new mortality tables and improvement scales reflecting improved life expectancies and an expectation that the trend will continue. An analysis of FirstEnergy pension and OPEB plan mortality data indicated the use of the RP2000 mortality table with projection scale BB2D was most appropriate. As such, the RP2000 mortality table with projection scale BB2D was utilized to determine the 2014 benefit cost and obligation as of December 31, 2014 for the FirstEnergy pension and OPEB plans. The impact of using the RP2000 mortality table with projection scale BB2D resulted in an increase to the projected benefit obligation of $373 million and $21 million for the pension and OPEB plans, respectively, and was included in the 2014 pension and OPEB mark-to-market adjustment.

Based on discount rates of 4.25% for pension, 4.00% for OPEB and an estimated return on assets of 7.75%, FirstEnergy expects its 2015 pre-tax net periodic postemployment benefit credits (including amounts capitalized) to be approximately $8 million (excluding any actuarial mark-to-market adjustments that would be recognized in 2015). The following table reflects the portion of pension and OPEB costs that were charged to expense, including any pension and OPEB mark-to-market adjustments, in the three years ended December 31, 2014.

Postemployment Benefits Expense (Credits)	**2014**	**2013**	**2012**
		(In millions)	
Pension	$ 939	$ (134)	$ 596
OPEB	(101)	(196)	(34)
Total	$ 838	$ (330)	$ 562

Health care cost trends continue to increase and will affect future OPEB costs. The 2014 composite health care trend rate assumptions were approximately 7.0-7.5%, compared to 7.25-7.75% in 2013, gradually decreasing to 4.5% 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**	**Pension**	**OPEB**	**Total**
			(In millions)	
Discount rate	Decrease by .25%	289	20	$ 309
Long-term return on assets	Decrease by .25%	14	1	$ 15
Health care trend rate	Increase by 1.0%	N/A	22	$ 22

Please see Note 3, Pension and Other Postemployment Benefits for additional information

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, an 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 utilizes the income approach, based upon discounted cash flows to estimate fair value. See Note 1, Organization and Basis of Presentation.

FirstEnergy reviews the probability of recovery of regulatory assets at each balance sheet date and whenever new events occur. Similarly, FirstEnergy records regulatory liabilities when a determination is made that a refund is probable or when ordered by a commission. Factors that may affect probability include changes in the regulatory environment, issuance of a regulatory commission order or passage of new legislation. If recovery of a regulatory asset is no longer probable, FirstEnergy will write off that regulatory asset as a charge against earnings.

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.

Conditional retirement obligations associated with tangible long-lived assets are recognized at fair value in the period in which they are incurred if a reasonable estimate can be made, even though there may be uncertainty about timing or method of settlement.

When settlement is conditional on a future event occurring, it is reflected in the measurement of the liability, not the timing of the liability recognition.

AROs as of December 31, 2014, are described further in Note 13, Asset Retirement Obligations.

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. See Note 5, Taxes for additional information.

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. FirstEnergy evaluates goodwill for impairment annually on July 31 and more frequently if indicators of impairment arise. In evaluating goodwill for impairment, FirstEnergy assesses qualitative factors to determine whether it is more likely than not (that is, likelihood of more than 50%) 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 or bypasses the qualitative assessment, then the two-step quantitative goodwill impairment test is performed to identify a potential goodwill impairment and measure the amount of impairment to be recognized, if any.

FirstEnergy performed a quantitative assessment of the Regulated Distribution, Regulated Transmission and CES reporting units as of July 31, 2014. The fair values for each of the reporting units were calculated using a discounted cash flow analysis and indicated no impairment of goodwill.

The fair value of the CES reporting unit exceeded its carrying value by approximately 10%, impacted by near term weak economic conditions and low energy and capacity prices. Key assumptions incorporated into the CES discounted cash flow analysis requiring significant management judgment included: discount rates, future energy and capacity pricing, projected operating income, capital expenditures, including the impact of pending carbon pollution and other environmental regulation, and terminal multiples. The July 31, 2014 assessment for this reporting unit included a discount rate of 8.5% and a terminal multiple of 7.0x earnings before, interest, taxes, depreciation, and amortization. Continued weak economic conditions, lower than forecasted power and capacity prices, and revised environmental requirements could have a negative impact on future goodwill assessments.

Key assumptions incorporated in the Regulated Distribution and Regulated Transmission discounted cash flow analysis requiring significant management judgment included: discount rates, growth rates, projected operating income, changes in working capital, projected capital expenditures, projected funding of pension plans, expected results of future rate proceedings, and terminal multiples.

See Note 1, Organization and Basis of Presentation for additional details.

NEW ACCOUNTING PRONOUNCEMENTS

In May 2014, the FASB issued Revenue from Contracts with Customers, requiring entities to recognize revenue by applying a five-step model in accordance with the core principle to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. In addition, the accounting for costs to obtain or fulfill a contract with a customer is specified and disclosure requirements for revenue recognition are expanded. This standard is effective for fiscal years beginning after December 15, 2016, with no early adoption permitted, and shall be applied retrospectively to each period presented or as a cumulative-effect adjustment as of the date of adoption. FirstEnergy is currently evaluating the impact on its financial statements of adopting this standard.

FIRSTENERGY SOLUTIONS CORP.

MANAGEMENT'S NARRATIVE
ANALYSIS OF RESULTS OF OPERATIONS

FES is a wholly owned subsidiary of FE. 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 AE Supply and MP), and owns, through its subsidiary, NG, FirstEnergy's nuclear generation facilities. FENOC, a wholly owned subsidiary of FE, 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. On February 12, 2014, FES sold its hydroelectric generation facility and recorded a pre-tax gain of $177 million associated with the sale in the first quarter of 2014.

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. In 2014, FES began to reduce its exposure to weather-sensitive loads and eliminate load obligations that do not adequately cover risk premiums. As part of this, FES eliminated future selling efforts in certain sales channels, such as Mass Market, medium commercial-industrial and select large commercial-industrial (Direct), to focus on a selective mix of retail sales channels, wholesale sales that hedge generation more effectively, and maintain a small open position to take advantage of market upside opportunities resulting from volatility similar to that experienced in the first quarter of 2014. Support for current customers in the channels to be exited will remain through their respective contract terms.

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 DR 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.

During January 2014, given higher customer usage associated with extreme weather conditions and unit unavailability, including the Beaver Valley Unit 1 outage, FES was required to purchase higher volumes of power. These extreme weather events, which included the polar vortex, caused an increase in the demand for electricity and natural gas throughout the PJM Region. Average prices during first quarter 2014 were nearly $68 per MWH, or double the three-year average of about $34 per MWH. Furthermore, prices during the 10 highest-price, most volatile days in the first quarter where the average round-the-clock day-ahead price at AD Hub was between $100 and $500 per MWH and more specifically on January 7, 2014, when real-time pricing exceeded $1,800 per MWH significantly impacted the results. Increased customer demand that was unhedged and replacement power requirements due to the timing of unplanned outages and derates contributed to purchasing additional volumes at these higher prices. Furthermore, in order to maintain system reliability, PJM incurred higher ancillary service costs, such as synchronous and operating reserves, throughout these extreme conditions. Approximately $800 million in ancillary service charges for the month of January 2014 were billed to all LSEs serving customers throughout the PJM Region based on load served, including FES. Certain of these costs are considered a "pass-through" event under existing contracts and were billed to commercial and industrial customers in 2014.

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: FirstEnergy's Business, Strategy and Outlook, Capital Resources and Liquidity, Guarantees and Other Assurances, Off-Balance Sheet Arrangements, Market Risk Information, Credit Risk and Outlook.

Results of Operations

Net income decreased $304 million in 2014 compared to 2013. The Pension and OPEB mark-to-market adjustments increased $378 million year over year primarily reflecting a lower discount rate and a lower mortality rate, which was offset by a lower loss on debt redemptions of $97 million. Excluding these charges, year over year earnings resulted from lower sales volumes reflecting FES' change in selling efforts and an increase in the costs incurred to serve contract sales due to extreme events that occurred in January 2014. Partially offsetting these items were lower operating expenses due to lower retail-related costs, and higher capacity revenues from higher auction prices. Additionally, operating results were impacted by a $110 million after-tax gain on the sale of certain hydro facilities in February 2014.

Revenues -

Total revenues decreased $29 million in 2014, compared to 2013, primarily due to decreased sales volumes in Direct and Governmental Aggregation sales channels, partially offset by higher volume in the POLR and Structured Sales channels. Revenues were also impacted by higher unit prices as a result of increased channel pricing and ancillary pass-through revenues associated with PJM expenses incurred in January 2014 as well as higher capacity revenues, as described above.

The decrease in total revenues resulted from the following sources:

Revenues by Type of Service	For the Years Ended December 31, 2014	2013	Increase (Decrease)
	(In millions)		
Contract Sales:			
Direct	$ 2,356	$ 2,865	$ (509)
Governmental Aggregation	1,184	1,185	(1)
Mass Market	452	448	4
POLR	893	763	130
Structured Sales	498	396	102
Total Contract Sales	5,383	5,657	(274)
Wholesale	394	252	142
Transmission	198	121	77
Other	169	143	26
Total Revenues	$ 6,144	$ 6,173	$ (29)

MWH Sales by Channel	For the Years Ended December 31, 2014	2013	Increase (Decrease)
	(In thousands)		
Contract Sales:			
Direct	43,961	55,327	(20.5)%
Governmental Aggregation	19,569	20,859	(6.2)%
Mass Market	6,773	6,761	0.2 %
POLR	15,559	14,505	7.3 %
Structured Sales	12,393	8,634	43.5 %
Total Contract Sales	98,255	106,086	(7.4)%
Wholesale	14	—	— %
Total MWH Sales	98,269	106,086	(7.4)%

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

	Source of Change in Revenues Increase (Decrease)				
MWH Sales Channel:	**Sales Volumes**	**Prices**	**Gain on Settled Contracts**	**Capacity Revenue**	**Total**
			(In millions)		
Direct	$ (589)	$ 80	$ —	$ —	$ (509)
Governmental Aggregation	(73)	72	—	—	(1)
Mass Market	1	3	—	—	4
POLR	55	75	—	—	130
Structured Sales	172	(70)	—	—	102
Wholesale	—	—	39	103	142

The Direct, Governmental Aggregation and Mass Market customer base was 2.1 million as of December 31, 2014, compared to *2.7 million as of December 31, 2013, reflecting the FES' efforts to reposition its sales portfolio to more effectively hedge its* generation as discussed above. Additionally, although unit pricing was higher year over year in the Direct, Governmental Aggregation and Mass Market channels noted above, the increase was primarily attributable to higher capacity expense as discussed below, which is a component of the retail price. The increase associated with capacity was partially offset by lower energy pricing built into the retail product at the time customers were acquired for 2014 sales. Beginning in the fourth quarter of 2011, when there was a significant decline in energy prices, FES' 2014 retail sales position was approximately 30% committed, whereas its 2013 retail sales position was approximately 60% committed, resulting in a greater proportion of 2014 sales and unit prices being impacted by the decline in the energy prices. Additionally, higher Direct unit prices were impacted by approximately $33 million of ancillary pass through revenues associated with PJM expenses incurred in January 2014.

The increase in POLR revenues of $130 million was due to higher rates associated with the capacity expense component of the rate discussed above and higher sales volumes. The increase in Structured Sales revenues of $102 million was due to higher sales volumes, partially offset by lower unit prices primarily due to market conditions related to extreme weather events in January 2014 that reduced the gains on various structured financial sales contracts.

Wholesale revenues increased $142 million due to a $103 million increase in capacity revenue from higher capacity prices and higher net gains of $39 million on financially settled contracts, primarily with AE Supply. Increased gains on financially settled contracts with AE Supply resulted from higher market prices associated with extreme weather and market conditions in January 2014. Capacity revenue is expected to increase in 2015 due to the results of the 2015/2016 BRA and decrease in the years shortly thereafter.

Transmission revenue increased $77 million due to higher congestion revenue associated with market conditions related to extreme weather events in the first quarter of 2014, as discussed above.

Other revenue increased $26 million primarily due to higher lease revenues from additional repurchased equity interests in affiliated sale and leasebacks since 2013. FES earns lease revenue associated with the equity interests it has purchased.

Operating Expenses -

Total operating expenses increased $743 million in 2014 compared to 2013.

The following table summarizes the factors contributing to the changes in fuel and purchased power costs in 2014 compared with 2013:

Operating Expense	Volumes	Prices	Loss on Settled Contracts	Capacity Expense	Total
	Source of Change Increase (Decrease)				
	(In millions)				
Fossil Fuel	$ (21)	$ 23	$ (3)	$ —	$ (1)
Nuclear Fuel	1	(9)	—	—	(8)
Affiliated Purchased Power	2	3	(220)	—	(215)
Non-affiliated Purchased Power[1]	(286)	813	(404)	315	438

[1] Realized losses on financially settled wholesale sales contracts of $252 million resulting from higher market prices were netted in purchased power.

Fuel costs decreased $9 million primarily due to a decrease in fossil generation volumes and a decrease in settlement and termination costs related to coal and transportation contracts. Excluding settlement and termination costs, fuel costs decreased $6 million. A decrease in fossil generation volumes, resulting from an increase in outages in 2014, was partially offset by higher unit prices, primarily driven by increased peaking generation. The nuclear fuel rate decreased as a result of the suspension of the DOE nuclear disposal fee, which was effective May 16, 2014. Terminations and settlements associated with damages on coal and transportation contracts were approximately $138 million and $141 million in 2014 and 2013, respectively. Excluding the impact of termination and settlement costs, if any, which cannot be estimated, unit prices are expected to decrease in 2015 as a result of lower expected peaking generation and a full-year benefit of the suspended DOE spent nuclear fuel fee.

Affiliated purchased power costs decreased $215 million primarily associated with net gains on financially settled contracts with AE Supply resulting from higher market prices in the first quarter of 2014.

Non-affiliated purchased power costs increased $438 million due to increased prices ($813 million) and higher capacity expenses ($315 million), partially offset by lower losses on financially settled contracts ($404 million) and lower volumes ($286 million). The increase in unit prices was primarily a result of market conditions related to extreme weather events in January 2014, partially offset by lower losses on financially settled contracts. Lower volumes were primarily due to decreased load requirements. The increase in capacity expense, which is a component of FES' retail price, was primarily the result of higher capacity rates associated with FES' retail sales obligations. Due to the change in FES' selling efforts, purchased power is expected to decrease in future periods. However, while lower MWH sales in 2015 will reduce capacity expense, higher capacity prices will result in higher capacity expense in 2015.

Other operating expenses increased $148 million in 2014, compared to 2013 due to the following:

- Fossil operating costs increased $2 million primarily due to higher professional and contractor costs, partially offset by lower labor and materials and equipment costs. Fossil operating expenses are expected to decrease primarily as a result of the scheduled deactivation of certain units by April 2015.
- Nuclear operating costs increased $6 million as a result of higher labor, contractor, materials and equipment costs. There were two refueling outages in each of 2014 and 2013, however, the duration of the outages in 2014 exceeded the prior year. Nuclear operating costs are expected to increase in 2015 as a result of three planned refueling outages.
- Transmission expenses increased $66 million primarily due to higher operating reserve and market-based ancillary costs associated with market conditions related to extreme weather events in January 2014, of which a portion were passed through to commercial and industrial customers, as discussed above. Additionally, effective June 1, 2013, network expenses associated with POLR sales in Pennsylvania became the responsibility of suppliers. Transmission expenses are expected to continue to decrease as a result of the change in selling efforts discussed above.
- Other operating expenses increased $74 million primarily due to an increase in mark-to-market expenses on commodity contract positions, and an impairment of deferred advertising costs associated with the elimination of future selling efforts in the Mass Market and certain Direct sales channels, partially offset by lower retail and marketing related costs. Retail and marketing related costs are expected to continue to decrease as a result of the change in selling efforts.

Pension and OPEB mark-to-market adjustments increased $378 million primarily reflecting a lower discount rate and revisions to mortality assumptions extending the expected life in key demographics used to measure related obligations in 2014.

Depreciation expense increased $13 million primarily due to an increase in depreciable base as a result of capital expenditures, and repurchasing interests in Beaver Valley Unit 2 sale and leasebacks since 2013. Depreciation is expected to increase in future periods as a result of higher capital expenditures for projects such as MATS compliance and the Davis-Besse steam generator replacement completed in mid-2014.

General taxes decreased $10 million primarily due to lower gross receipts taxes resulting from reduced retail sales volumes and reduced Ohio personal property taxes.

Other Expense -

Total other expense decreased $132 million in 2014, compared to 2013, primarily due to a lower loss on debt redemptions in connection with senior notes that were repurchased in 2013 ($97 million), lower net interest expense of $12 million due to debt redemptions and lower OTTI and higher investment income of $45 million primarily on NDT investments, partially offset by lower miscellaneous income of $22 million due to a 2013 pre-tax gain of $17 million on the sale of property to a regulated affiliate.

Discontinued Operations -

Discontinued operations increased net income $102 million in 2014 compared to 2013 primarily due to a pre-tax gain of approximately $177 million ($110 million after-tax) associated with the sale of certain hydro assets described above.

Income Tax Benefits -

FES' effective tax rates from continuing operations for the years 2014 and 2013 were 38.8% and 11.5%, respectively. The 2014 effective tax rate (on pre-tax losses) included a benefit resulting from a reduction in state deferred tax liabilities associated with changes in apportionment factors, but was offset by valuation allowances on local NOL carryforwards. In 2015, FES anticipates an effective tax rate of approximately 37% to 38%.

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 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. 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 contracts assets and liabilities as of December 31, 2014 are summarized by year in the following table:

Source of Information-Fair Value by Contract Year	**2015**	**2016**	**2017**	**2018**	**2019**	**Thereafter**	**Total**
				(In millions)			
Prices actively quoted[1]	$ (25)	$ —	$ —	$ —	$ —	$ —	$ (25)
Other external sources[2]	(11)	20	8	6	—	—	23
Prices based on models	16	2	2	—	—	—	20
Total	$ (20)	$ 22	$ 10	$ 6	$ —	$ —	$ 18

(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, 2014, a 10% adverse change in commodity prices would increase net income by approximately $1 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	2015	2016	2017	2018	2019	There-after	Total	Fair Value
				(In millions)				
Assets:								
Investments Other Than Cash and Cash Equivalents:								
Fixed Income	$ —	$ —	$ —	$ —	$ —	$ 801	$ 801	$ 801
Average interest rate	—%	—%	—%	—%	—%	4.0%	4.0%	
Liabilities:								
Long-term Debt:								
Fixed rate	$ 96	$ 25	$ 34	$ 141	$ 90	$ 2,619	$ 3,005	$ 3,149
Average interest rate	8.2%	8.2%	3.2%	5.6%	3.0%	4.4%	4.6%	
Variable rate	$ —	$ —	$ —	$ 6	$ —	$ 86	$ 92	$ 92
Average interest rate	—%	—%	—%	—%	—%	0.10%	0.10%	

Equity Price Risk

NDT funds have been established to satisfy NG's nuclear decommissioning obligations. Included in FES' NDT are fixed income, equities and short-term investments carried at market values of approximately $801 million, $360 million and $160 million, respectively, as of December 31, 2014, excluding $44 million of net receivables, payables and accrued income. A hypothetical 10% decrease in prices quoted by stock exchanges would result in a $36 million reduction in fair value as of December 31, 2014. NG recognizes in earnings the unrealized losses on AFS securities held in its NDT as OTTI. A decline in the value of FES' NDT or a significant escalation in estimated decommissioning costs could result in additional funding requirements.

Credit Risk

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

Wholesale Credit Risk

FES measures wholesale credit risk as the replacement cost for derivatives in power, natural gas, coal and emission allowances, adjusted for amounts owed to, or due from, counterparties for settled transactions. The replacement cost of open positions represents unrealized gains, net of any unrealized losses, where FES has a legally enforceable right of offset. 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.

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 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, FES' retail credit risk may be adversely impacted.

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 2014 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 2014.

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 published in 2013, 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, 2014. The effectiveness of the Company's internal control over financial reporting, as of December 31, 2014, 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 2014 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 2014.

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 published in 2013, 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, 2014.

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, 2014 and 2013, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2014 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 Item15(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, 2014, based on criteria established in *Internal Control - Integrated Framework (2013)* 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 17, 2015

Report of Independent Registered Public Accounting Firm

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

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, comprehensive income, common stockholder's equity, and cash flows, present fairly, in all material respects, the financial position of FirstEnergy Solutions Corp. and its subsidiaries at December 31, 2014 and 2013, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2014 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 17, 2015

FIRSTENERGY CORP.
CONSOLIDATED STATEMENTS OF INCOME

(In millions)	For the Years Ended December 31, 2014	2013	2012
REVENUES:			
Electric utilities	$ 9,871	$ 9,451	$ 9,782
Unregulated businesses	5,178	5,441	5,473
Total revenues*	15,049	14,892	15,255
OPERATING EXPENSES:			
Fuel	2,280	2,496	2,471
Purchased power	4,716	3,963	4,246
Other operating expenses	3,962	3,593	3,760
Pension and OPEB mark-to-market adjustment	835	(256)	609
Provision for depreciation	1,220	1,202	1,119
Amortization (deferral) of regulatory assets, net	12	539	(68)
General taxes	962	978	984
Impairment of long-lived assets	—	795	—
Total operating expenses	13,987	13,310	13,121
OPERATING INCOME	1,062	1,582	2,134
OTHER INCOME (EXPENSE):			
Loss on debt redemptions	(8)	(132)	—
Investment income	72	33	77
Interest expense	(1,073)	(1,016)	(1,001)
Capitalized financing costs	118	103	90
Total other expense	(891)	(1,012)	(834)
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	171	570	1,300
INCOME TAXES (BENEFITS)	(42)	195	545
INCOME FROM CONTINUING OPERATIONS	213	375	755
Discontinued operations (net of income taxes of $69, $9 and $8, respectively) (Note 19)	86	17	16
NET INCOME	299	392	771
Income attributable to noncontrolling interest	—	—	1
EARNINGS AVAILABLE TO FIRSTENERGY CORP.	$ 299	$ 392	$ 770
EARNINGS PER SHARE OF COMMON STOCK:			
Basic - Continuing Operations	$ 0.51	$ 0.90	$ 1.81
Basic - Discontinued Operations (Note 19)	0.20	0.04	0.04
Basic - Earnings Available to FirstEnergy Corp.	$ 0.71	$ 0.94	$ 1.85
Diluted - Continuing Operations	$ 0.51	$ 0.90	$ 1.80
Diluted - Discontinued Operations (Note 19)	0.20	0.04	0.04

Diluted - Earnings Available to FirstEnergy Corp.	$ 0.71	$ 0.94	$ 1.84
WEIGHTED AVERAGE NUMBER OF SHARES OUTSTANDING:			
Basic	420	418	418
Diluted	421	419	419
DIVIDENDS DECLARED PER SHARE OF COMMON STOCK	$ 1.44	$ 1.65	$ 2.20

* Includes excise tax collections of $420 million, $458 million and $484 million in 2014, 2013 and 2012, 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, 2014	2013	2012
NET INCOME	$ 299	$ 392	$ 771
OTHER COMPREHENSIVE INCOME (LOSS):			
Pension and OPEB prior service costs	(76)	(160)	(115)
Amortized gains (losses) on derivative hedges	(2)	3	1
Change in unrealized gain on available-for-sale securities	26	(10)	(6)
Other comprehensive loss	(52)	(167)	(120)
Income tax benefits on other comprehensive loss	(14)	(66)	(79)
Other comprehensive loss, net of tax	(38)	(101)	(41)
COMPREHENSIVE INCOME	261	291	730
Comprehensive income attributable to noncontrolling interest	—	—	1
COMPREHENSIVE INCOME AVAILABLE TO FIRSTENERGY CORP.	$ 261	$ 291	$ 729

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)	December 31, 2014	December 31, 2013
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 85	$ 218
Receivables-		
Customers, net of allowance for uncollectible accounts of $59 in 2014 and $52 in 2013	1,554	1,720
Other, net of allowance for uncollectible accounts of $5 in 2014 and $3 in 2013	225	198
Materials and supplies, at average cost	817	752
Prepaid taxes	128	226
Derivatives	159	166
Accumulated deferred income taxes	518	366
Collateral	230	155
Other	160	212
	3,876	4,013
PROPERTY, PLANT AND EQUIPMENT:		
In service	47,484	44,228
Less — Accumulated provision for depreciation	14,150	13,280
	33,334	30,948
Construction work in progress	2,449	2,304
	35,783	33,252
INVESTMENTS:		
Nuclear plant decommissioning trusts	2,341	2,201
Other	881	903
	3,222	3,104
ASSETS HELD FOR SALE (Note 19)	—	235
DEFERRED CHARGES AND OTHER ASSETS:		
Goodwill	6,418	6,418
Regulatory assets	1,411	1,854
Other	1,456	1,548
	9,285	9,820
	$ 52,166	$ 50,424
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Currently payable long-term debt	$ 804	$ 1,415
Short-term borrowings	1,799	3,404
Accounts payable	1,279	1,250
Accrued taxes	490	485
Accrued compensation and benefits	329	351
Derivatives	167	111
Other	693	621
	5,561	7,637

CAPITALIZATION:		
Common stockholders' equity-		
Common stock, $0.10 par value, authorized 490,000,000 shares - 421,102,570 and 418,628,559 shares outstanding as of December 31, 2014 and December 31, 2013, respectively	42	42
Other paid-in capital	9,847	9,776
Accumulated other comprehensive income	246	284
Retained earnings	2,285	2,590
Total common stockholders' equity	12,420	12,692
Noncontrolling interest	2	3
Total equity	12,422	12,695
Long-term debt and other long-term obligations	19,176	15,831
	31,598	28,526
NONCURRENT LIABILITIES:		
Accumulated deferred income taxes	7,057	6,968
Retirement benefits	3,932	2,689
Asset retirement obligations	1,387	1,678
Deferred gain on sale and leaseback transaction	824	858
Adverse power contract liability	217	290
Other	1,590	1,778
	15,007	14,261
COMMITMENTS, GUARANTEES AND CONTINGENCIES (Note 15)		
	$ 52,166	$ 50,424

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